

THE STATE OF SOUTH CAROLINA
In the Supreme Court

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S.C. SUPREME COURT

APPEAL FROM THE PUBLIC SERVICE COMMISSION

Appellate Case No. 2018-001165 and 2018-002117

Commission Docket No. 2018-2-E

South Carolina Coastal Conservation
League and Southern Alliance for Clean
Energy,

Appellants,

v.

South Carolina Electric & Gas, CMC Steel
South Carolina, South Carolina Energy Users
Committee, South Carolina Solar Business
Alliance, LLC, Southern Current, LLC and
South Carolina Office of Regulatory Staff,

Respondents;

and

South Carolina Solar Business Alliance, LLC,

Appellant,

v.

South Carolina Coastal Conservation
League and Southern Alliance for Clean
Energy, South Carolina Electric and Gas, CMC
Steel South Carolina, South Carolina Energy
Users Committee, Southern Current, LLC, and
South Carolina Office of Regulatory Staff,

Of whom South Carolina Electric & Gas and
South Carolina Office of Regulatory Staff, are

Respondents.

RECORD ON APPEAL
Volume III of IV

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CHAIRMAN WHITFIELD: Mr. Whitt or Mr. Snowden, any – your turn for questions of this panel.

MR. WHITT: We do have questions, and Attorney Ben Snowden is going to handle those questions.

CHAIRMAN WHITFIELD: Okay. Come forward, Mr. Snowden.

CROSS EXAMINATION

BY MR. SNOWDEN:

Q Mr. Rooks, Mr. Raftery, Dr. Lynch, it's nice to see you all again. Good afternoon. I have some bad news for you Dr. Lynch: Most of my questions are for you again.

Dr. Lynch, your current position is manager of Resource Planning for the company; is that right?

A [LYNCH] That's right.

Q Okay. And what are your responsibilities as manager of Resource Planning?

A [LYNCH] I supervise the work of the people in the department, and that falls in three – arguably four – traditional areas. So, I'm responsible for forecasting

1 customer sales, revenue, that sort of thing; I supervise
2 the load research program that the company conducts; I'm
3 also responsible for the traditional generation planning
4 that utilities do. We also coordinate and write most of
5 the IRP; we're responsible for getting that filed.

6 **Q** Okay. So can you describe in a little more detail your
7 involvement in the development of the IRP?

8 **A** [LYNCH] Well –

9 **Q** Let me ask another question. That's the responsibility
10 of your department?

11 **A** [LYNCH] Well, it's – I guess it's not true that the
12 whole company, but there's a lot of departments that
13 contribute to it. But, in essence, the IRP – the major
14 parts of it – are the forecast, the demand-side
15 management section, and then the resource plan. And the
16 forecast and the resource plan come under Resource
17 Planning. The demand-side management and energy
18 efficiency come under Mr. Raftery. So his people help
19 write it, and then there's always a lot of discussion
20 about environmental regulations, so we reach out to the
21 environmental people, and other people in the
22 organization. But it's sort of a corporate effort,
23 almost. We coordinate it and maybe write a lot of it.

24 **Q** Okay. So your department is ultimately responsible for
25 the resource plan for the IRP?

1 A [LYNCH] Yes, I'd say that.

2 Q And so you would've been involved in the development of
3 the 2018 IRP filed with the Commission recently?

4 A [LYNCH] Yes.

5 Q So at least with respect to planning, there would
6 probably not be statements in the IRP that you would
7 disagree with.

8 A [LYNCH] I sure hope not, but —

9 Q Not to your knowledge.

10 A [LYNCH] Not to my knowledge.

11 Q Okay.

12 A [LYNCH] Thank you for that.

13 Q So you testified that you're responsible for developing
14 the company's generation expansion plan; is that right?

15 A [LYNCH] Yeah, well, we study it and recommend. I mean,
16 I don't decide on it, but, yes, we're intimately
17 involved in that process. Yes.

18 Q So the generation expansion plan is just a component of
19 the IRP?

20 A [LYNCH] Yes.

21 Q In the context of the fuel proceeding, you're
22 responsible for preparing the avoided-cost calculations
23 that go into the PR-1 and PR-2 tariffs; is that right?

24 A [LYNCH] That's right, yeah.

25 Q Okay. So you decide how those calculations are

1 performed and what the data that are used in those
2 calculations are?

3 A [LYNCH] Well, my team, yes.

4 Q Okay. And how long have you been involved with the
5 calculation of avoided-cost rates for the company?

6 A [LYNCH] A very long time. I don't know if it would go
7 back to PURPA. It would have to be since the early
8 '90s.

9 Q Okay. And so, then, you're pretty knowledgeable about
10 avoided-cost issues, I assume?

11 A [LYNCH] Yes.

12 Q All right. And do you continue to educate yourself on
13 developments in that field?

14 A [LYNCH] Yeah, I suppose I do. Yes.

15 Q How do you do that?

16 A [LYNCH] Mostly, Internet. As I get time, I might do
17 searches and things of that sort.

18 Q Okay. And do you keep up with how other utilities
19 calculate avoided costs?

20 A [LYNCH] I'm not sure I keep up. I'm interested. So if
21 I can find somebody who did a study and I have the time,
22 I would read it, yes.

23 Q So, more generally, do you keep up with developments in
24 the energy industry or do you make efforts to keep up
25 with developments in the energy industry that might be

1 relevant to the company and its customers, in terms of
2 planning?

3 A [LYNCH] Sure. Yes, I think so.

4 Q And you consider yourself well-informed on those
5 developments?

6 A [LYNCH] I think so, yes.

7 Q All right. And so you're generally familiar with the
8 PURPA statute, as it relates to the company's
9 obligations?

10 A [LYNCH] Yes.

11 Q Okay. And you're generally familiar with the relevant
12 FERC regulations and FERC orders related to avoided
13 costs?

14 A [LYNCH] Yes, I think generally. Yeah, generally. I
15 wouldn't say I'm an expert on PURPA or FERC regulations
16 and that sort of thing. I think I know enough to cover
17 the responsibilities I have with the company.

18 Q Enough to do your job?

19 A [LYNCH] Enough to do my job, yes.

20 Q Are the purposes for which the company would calculate
21 avoided-cost rates outside of the context of the fuel
22 case?

23 A [LYNCH] The company's required to file -- make an
24 avoided-cost filing every two years, as a result of
25 PURPA. So every even year, in June, there's a filing.

1 I think it comes to the – I believe we filed with the
2 Commission and maybe the Commission files it with FERC.

3 Q And those are the filings that are periodically required
4 by FERC regulation?

5 A [LYNCH] Right, every two years.

6 Q Are there any other reasons the company would be
7 calculating avoided-cost rates, outside of the context
8 of this proceeding or the –

9 A [LYNCH] Yeah, I can't think of – off the top of it, I
10 can't think of a reason.

11 Q Before we move on, I do want to – I'd like to clarify
12 something. I think maybe you could help clarify
13 something that was discussed a little earlier. So, the
14 company performed a set of avoided energy cost
15 calculations using what I'm going to call the old
16 methodology, sort of the traditional methodology, that
17 was approved by the Commission in the last proceeding;
18 is that right?

19 A [LYNCH] You mean, did we calculate avoided costs
20 subtracting – there's always a difference in revenue
21 requirements; we're married to that. I don't know how
22 else we would calculate avoided costs. So last year and
23 the year before that, we were subtracting a 100-megawatt
24 profile to get a change case from the base case, and
25 doing the avoided energy cost that way.

1 Q Okay. Since that last proceeding, in the context of
2 preparing your testimony for this proceeding, did you
3 perform an avoided energy cost calculation using the
4 same load profile that you used last year, that every-
5 hour – 100-megawatt-every-hour profile?

6 A [LYNCH] Right. Yes, I did. And Exhibit JML-3, if I've
7 got the number correct, the whole purpose of that was to
8 calculate the difference in avoided energy cost if we
9 used a solar profile versus the 100-megawatt profile,
10 with the idea of demonstrating to interested parties
11 that it was no longer appropriate, because we have so
12 much solar on the system.

13 Q And that information was produced to the Coastal
14 Conservation League, is that right, in response to a
15 discovery request?

16 A [LYNCH] Well, a lot of the detail data was in my direct
17 testimony.

18 Q Okay. But the company did – well, let me ask this. Did
19 the company produce avoided capacity cost calculations
20 using the load profile that was employed last year,
21 instead of the solar-specific load profile?

22 A [LYNCH] No. You know, so, to take that around-the-clock
23 resource, dispatchable unit or 100 percent we did not do
24 for capacity.

25 Q So do you know if any other party in this matter

1 requested calculations of avoided capacity costs using
2 the same methodology that was employed last year, with
3 updated inputs?

4 A [LYNCH] I think – I think someone requested that, but my
5 contention is we're using the same methodology,
6 difference in revenue requirement. So I find the
7 question sort of a non sequitur, in my –

8 Q Well, just –

9 A [LYNCH] – my mind.

10 Q Well, let's just restrict it to the load-profile issue,
11 right? This year, you are using a solar-specific load
12 profile, and in the last proceeding you used a round-
13 the-clock 100-megawatt profile.

14 A [LYNCH] That's correct.

15 Q Okay. So those are two different load profiles –

16 A [LYNCH] Yes.

17 Q – whether its methodology is – maybe assuming that
18 question, we don't have to answer. But you did not
19 perform an avoided capacity cost calculation using that
20 24-hour 100-megawatt profile.

21 A [LYNCH] That is correct, I did not.

22 Q And so no such – no information on avoided capacity
23 costs using that load profile was produced to any other
24 party in this matter; is that right?

25 A [LYNCH] Not to my knowledge, no, I don't believe so.

1 Q So avoided energy costs, yes, avoided capacity costs,
2 no.

3 A [LYNCH] Yes, that's correct.

4 Q Okay. So, Dr. Lynch, the purpose of your testimony in
5 this matter is to discuss the company's avoided costs
6 for power purchases under PURPA?

7 A [LYNCH] Yes.

8 Q Okay. And in your testimony, you discuss the approach
9 the company takes to calculating avoided energy –
10 avoided costs.

11 A [LYNCH] Yes.

12 Q Okay. And the purpose of your testimony, in part, is to
13 show why the proposed updates to the PR-1 and PR-2
14 schedules are reasonable and are technically justified?

15 A [LYNCH] Yes.

16 Q Okay. And in your view, the company's proposals do not
17 involve any significant changes to methodology for
18 calculating avoided costs – sorry. In your review, the
19 company's current proposals for the PR-1 and PR-2 rate
20 schedules do not involve any significant changes to its
21 methodology?

22 A [LYNCH] Not to the methodology, no.

23 Q And do the elements of the company's proposals include
24 limiting the availability of the PR-2 rate to solar QFs
25 only?

1 A [LYNCH] That's part of the – yes, that's part of it.

2 Q And does the company's proposal include no longer
3 offering standard rates to non-solar QFs that are over
4 100 kilowatts?

5 A [LYNCH] That would be a PR-2 rate for non-solar; we
6 propose not to do that.

7 Q And do you also propose updating the PR-2 rate going
8 forward only on an as-needed basis, instead of twice a
9 year?

10 A [LYNCH] Well, I think it would be updated once a year at
11 the fuel hearing, and then the thinking is update it as
12 needed.

13 Q But not twice a year?

14 A [LYNCH] Not necessarily. Heck, it could be three times
15 a year. And maybe a clarification: The company, every
16 summer, every year, it updates all its forecasts as part
17 of the planning process, and so the thinking is at the
18 end of the summer we'll have a new forecast – economics,
19 whatever's driving customers, that sort of thing, new
20 fuel prices and everything – so I'm expecting that we
21 would calculate the avoided costs and talk to the Rate
22 Department and they would probably decide, or
23 Regulation, something of that sort.

24 Q Okay.

25 A [LYNCH] But if it's not significant, if there's no

1 significant change, it doesn't seem reasonable to make
2 the change.

3 **Q** So, when you say the company updates its forecasts in
4 the summer, first off, when in the summer does that
5 happen?

6 **A** [LYNCH] It spans several months. So usually we have to
7 be finished towards the end of August, so you start as
8 soon as you can because there's a lot that gets done.

9 **Q** Right. So does that forecast include – is that just a
10 load forecast or are there other elements to the
11 forecast?

12 **A** [LYNCH] Oh, every – other elements, too.

13 **Q** So, including generation resources?

14 **A** [LYNCH] Yes. So, we would collect economic data,
15 demographics, whatever is necessary, and then update the
16 customer forecast, average use kWh, we do the revenue,
17 peak demand.

18 **Q** So at the end of the summer, though, you have a new
19 updated picture of what the company's needs are and also
20 what its ability to supply power is?

21 **A** [LYNCH] Yeah, and I guess I should say energy and
22 revenue maybe by the end of August. Sometime in
23 September, the balance is probably due.

24 **Q** Okay. Going back to the company's proposals here, do
25 the company's proposals include calculating avoided

1 costs based on a solar-specific generation profile
2 instead of the constant 100-megawatt profile?

3 A [LYNCH] Yes.

4 Q Okay. And do they include calculating capacity costs
5 based on a 21 percent winter reserve margin?

6 A [LYNCH] Yes. Yeah.

7 Q Does the company propose – I'm sorry. Do the company's
8 proposed rates reflect the conclusion that solar QFs
9 provide no capacity value to the system?

10 A [LYNCH] Incremental solar does not. We have 865 –
11 actually, 875 megawatts now; we signed a PPA last week.
12 So 875 megawatts now do provide some capacity type
13 value.

14 Q But no new solar.

15 A [LYNCH] But beyond that, the next 100 megawatts of
16 solar, we contend, do not add capacity value.

17 Q And do the company's proposals include offering separate
18 rates for solar versus non-solar QFs that are under 100
19 kilowatts?

20 A [LYNCH] Yes, in the PR-1 rate. Yes.

21 Q Dr. Lynch, you've testified on behalf of the company in
22 previous fuel cases; is that right?

23 A [LYNCH] Yes.

24 Q Okay. And you did so in 2016 when the PR-2 rate
25 schedule was first approved?

1 A [LYNCH] Yes.

2 Q Okay. And you did so in 2017 when the currently
3 effective PR-2 rates were approved?

4 A [LYNCH] Yes, sir.

5 Q In each case, you testified under oath?

6 A [LYNCH] Yes, sir.

7 Q And you testified in those proceedings, prior
8 proceedings, that the company's calculations of avoided
9 costs were reasonable?

10 A [LYNCH] Yes.

11 Q Okay. And the Commission has found that those were
12 reasonable?

13 A [LYNCH] Yes. They approved them, yes.

14 Q And did you ever have occasion to review the Commission
15 orders in 2016 and 2017, approving the company's updates
16 to the PR-2 tariff?

17 A [LYNCH] I believe I read them. It's been awhile.

18 Q Yeah, understandably. But you're generally familiar
19 with the Commission's rulings?

20 A [LYNCH] I'm afraid – I'm afraid to say yes, because I'm
21 not sure. I know that they approved the resulting
22 rates.

23 Q To the extent necessary to do your job well, you know.

24 A [LYNCH] Yeah, I can think they – yeah.

25 Q So, under PURPA, utilities are obligated to purchase

1 energy and capacity from qualifying facilities at
2 avoided cost; is that right?

3 A [LYNCH] I wonder if the law just says "purchase energy."

4 Q I – well –

5 A [LYNCH] You know what I mean?

6 Q Under PURPA, as implemented by the Federal Energy
7 Regulatory Commission?

8 A [LYNCH] Does it say energy and capacity?

9 Q It does say energy and capacity.

10 A [LYNCH] Because we're provided, when somebody delivers
11 it, it's really energy. The capacity is the ability to
12 generate.

13 Q Right.

14 A [LYNCH] But you're required to pay the avoided cost for
15 the energy provided.

16 Q Right. And whatever avoided cost of capacity that –

17 A [LYNCH] If there's capacity involved, that would be part
18 of the –

19 Q Okay. So, under PURPA and FERC regulations, avoided-
20 cost calculations are supposed to be based on current
21 data and projections of the utilities of avoided costs
22 for a forward-going basis?

23 A [LYNCH] Well, I mean, the regulation says avoided cost,
24 and they are defined as a cost that would be avoided
25 through the purchase such that you would incur as it –

1 you would incur these costs were it not for the purchase
2 of the QF.

3 **Q** But current data makes for a more accurate calculation
4 of avoided costs; is that right?

5 **A** [LYNCH] Yes.

6 **Q** So, the company uses the difference-in-revenue-
7 requirements methodology to calculate avoided costs; is
8 that right?

9 **A** [LYNCH] Yes.

10 **Q** Okay. So DRR, for short? Is that the common
11 abbreviation?

12 **A** [LYNCH] That's okay, yeah.

13 **Q** And is this an industry-standard approach?

14 **A** [LYNCH] Oh, I'd say yes.

15 **Q** And it is one of the methodologies for calculating
16 avoided cost that FERC describes in – well, are you
17 familiar with FERC Order 69? The original FERC order?

18 **A** [LYNCH] I can't say –

19 **Q** Okay.

20 **A** [LYNCH] – I am. But there are a lot of books and
21 manuals where they talk about how to calculate avoided
22 cost, and difference in revenue requirements is one of
23 the three main methods of calculating it.

24 **Q** Okay. And how does – just very briefly, how does the
25 DRR method work?

1 **A** [LYNCH] Well, you can take a difference in revenue
2 requirement, and to be honest I don't know how else you
3 would calculate avoided cost, because they are, sort of
4 by definition, the costs that are going to be avoided.
5 So you would find what's the cost in your plan without
6 the QF, put the QF in the plan, zero cost, and say,
7 "Well, now, what are your costs?" You have two plans,
8 and the change is the impact of what the QF purchase has
9 done. That's the cost we've avoided.

10 **Q** Okay. You compare a base case to a change case?

11 **A** [LYNCH] And get a difference in revenue requirements,
12 yes.

13 **Q** And the base case is defined by the company's existing
14 fleet of generators and the hourly load profile to be
15 supplied by those generators?

16 **A** [LYNCH] For us here in the fuel hearing, it's typically
17 the resource plan that we usually file with the IRP,
18 unless there's a change. I think like last year there
19 was a small change between what we filed in the fuel
20 hearing and the plan that was filed in the IRP.

21 **Q** Okay. And you would compare the base case and the
22 change case using the PROSYM computer software package?

23 **A** [LYNCH] To get – estimate the change in energy, we would
24 use the PROSYM. It dispatches the system and estimates
25 the production costs. So what are your production costs

1 without the QF purchase, what are your production costs
2 with the QF purchase, and take the difference.

3 Q But you would not use PROSYM to calculate capacity?

4 A [LYNCH] No. It doesn't do capacity.

5 Q That's not part of the functionality of that software?

6 A [LYNCH] That's correct.

7 Q What is the period of time over which you're calculating
8 rates for the PR-2 tariff?

9 A [LYNCH] Well, I calculate avoided cost for the 15-year
10 IRP planning horizon.

11 Q So, we talked about the change – sorry – talked about
12 the base case as being defined by the generation plan of
13 the IRP. And so the change case is the – is that plan
14 with the selected load profile sort of backed out of it?
15 Is that right?

16 A [LYNCH] Well, you would assume, then, you make a QF
17 purchase, so there would be a supply. Then you figure
18 out what your change plan is there.

19 Q So it's safe to say that the base case and the change –
20 how the base case and the change case are defined would
21 determine the results of the calculation?

22 A [LYNCH] Well, a lot of other stuff goes into it, but
23 that's the main driver, yes.

24 Q Okay. And that's with respect to energy costs.

25 A [LYNCH] Well, with energy, we would take the resource

1 plan, and then we wouldn't – you don't change the – the
2 only change we make in the resource plan is we just
3 assume we have that purchase folded in, and then just
4 take the difference in revenue requirements, as a
5 result. For capacity, you have to see – you start
6 moving it around and look for the fixed costs, capital
7 costs, associated with whatever changes in the need for
8 capacity.

9 Q Okay. So, just to clarify, going back to the change
10 case, the way the change case is defined here is a
11 little bit different than how it was defined last year;
12 is that right?

13 A [LYNCH] Well, last year, we were subtracting – you know,
14 for avoided energy, for example, we subtract 100
15 megawatts in every hour. And we've done that again for
16 the PR-1 non-solar rate. But for solar, we're starting
17 to use a solar profile to get a more accurate estimate
18 of avoided energy costs.

19 Q Okay. So it's not exactly the same approach as between
20 2017 and 2018; is that right?

21 A Well, fundamentally, it's difference in revenue
22 requirements. My contention is it's the same
23 methodology, but the situation has changed. As I
24 mentioned, 875 megawatts on the system causes problems
25 in dispatching around all the energy that's produced by

1 the solar, causes problems on the dispatching. And even
2 on PROSYM model, which I was surprised, it was picking
3 up some of those integration costs, and that's why we're
4 getting that Delta.

5 Q And so you think that change necessitates going from a
6 constant 24-hour load profile to the solar-specific load
7 profile?

8 A [LYNCH] Oh, absolutely. Absolutely.

9 Q And does this change impact the results of the avoided-
10 cost calculation?

11 A [LYNCH] Yeah, and that's what I showed in my Exhibit -3,
12 JML-3. We did a study to see what that difference is
13 going to be.

14 Q Okay. Is it important to have a base case that
15 accurately reflects the reality of the company's system?

16 A [LYNCH] I would guess, yeah.

17 Q And all things being equal, you would agree that having
18 a more accurate base case would yield a more accurate
19 calculation of avoided cost?

20 A [LYNCH] Yeah.

21 Q And with respect to avoided capacity cost, having a more
22 accurate generation plan would give you a more accurate
23 picture of capacity costs?

24 A [LYNCH] Yes.

25 Q Dr. Lynch, I'd like you to look at an exhibit, your

1 Exhibit JML-1, which I think has been marked as part of
2 Hearing Exhibit No. 5. It is the table that was
3 attached to JML-1, to your direct testimony. It's a
4 single page, and the heading is "SCE&G Forecast of
5 Summer Loads and Resources - 2018 IRP."

6 A [LYNCH] Yes, I've got it.

7 Q Okay. And this is – well, what is this?

8 A [LYNCH] This is a resource plan, and we filed it with
9 the IRP?

10 Q And does this represent the assumptions about load and
11 capacity that are used for the base case in the DRR
12 model?

13 A [LYNCH] Yes.

14 Q Okay. And does this also represent the assumptions
15 about load and capacity that are used in calculation of
16 avoided capacity cost?

17 A [LYNCH] Well, this would be the plan that would be
18 changed from a purchase of –

19 Q Okay.

20 A [LYNCH] Yes.

21 Q All right. So this is what you start with, here.

22 A [LYNCH] Yes, yes, yes.

23 Q And so, rows four through six here, under "System
24 Capacity," those represent the capacity sort of
25 currently on the system in each year?

1 A [LYNCH] Well, six is demand response.

2 Q Oh, I'm sorry. Yes.

3 A [LYNCH] And most of that is existing demand response
4 until you get to 2020, in the winter of 2020. There's a
5 jump in the demand response because we envision – we
6 hope to have a demand-response program to address the
7 winter. With a 21 percent winter reserve margin and a
8 lot of that winter peak being spiked, the company
9 doesn't really want to build a power plant to meet that
10 short period of time. So the hope is to come up with a
11 peak-clipping program for the winter, so that's part of
12 our supply plan and we put 100 megawatts in, but it
13 might be more than that. Maybe if we can get 200, we
14 might.

15 Q Okay.

16 A [LYNCH] It's sort of a placeholder.

17 Q All right. So the plan is to have a peak-clipping
18 program or something like that in place in 2020?

19 A [LYNCH] Yes. For the winter, right.

20 Q And so, moving down to row nine where it says
21 "Base load," the numbers here represent additions to the
22 company's base-load generating capacity?

23 A [LYNCH] Yes.

24 Q Okay.

25 A [LYNCH] And I guess you skipped over eight on purpose?

1 Q I did. Well, what is eight, then? Let me ask.

2 A [LYNCH] I don't mean to be helping you.

3 Q By all means.

4 [Laughter]

5 A [LYNCH] Eight is peaking capacity. So out there in
6 2031, you fall below our reserve margin targets, so we
7 added that, a peaker.

8 Q All right. So you plan to build a – at least at this
9 point, you plan to build a peaker out in 2031?

10 A [LYNCH] And I guess it should be said – I mean, we're
11 not – I don't know if it's accurate to say we plan to
12 build it. The IRP represents a plan, and hopefully we
13 can even do better than the plan. So it's not a
14 decision. I think we –

15 Q Yeah, I –

16 A [LYNCH] – try to make sure everybody understands that.

17 Q Right. You are not currently committed to building a
18 peaker in 2031.

19 A [LYNCH] Right.

20 Q Right, okay.

21 A [LYNCH] Yes.

22 Q Are you currently committed to building or acquiring a
23 base-load plant in 2023?

24 A [LYNCH] No, I don't believe we are. No.

25 Q All right. And are you currently committed to acquiring

1 a base-load plant in 2018, winter?

2 A [LYNCH] There's some commitment there.

3 Q What kind of commitment?

4 A [LYNCH] Is it too late to ask Mr. Delk?

5 Q No. I will.

6 A I think there's – no, uh, yeah, that's the Columbia
7 Energy Center. We have arrangements with them. I'm not
8 sure the deal is consummated. I don't know where it is.

9 Q Okay.

10 A [LYNCH] The hope is, yes, that it's – we're committed to
11 it.

12 Q But this 504 megawatts represents the acquisition of the
13 Columbia Energy Center?

14 A [LYNCH] Right.

15 Q Okay. And that's planned in some way.

16 A [LYNCH] Yes. There's commitments and arrangements made.

17 Q Are you – is that – well, are you aware of any
18 contingencies that are built into that acquisition? Let
19 me ask that another way. Is that acquisition contingent
20 on approval of the Dominion merger?

21 A [LYNCH] Yeah, I don't know. I don't know.

22 Q You don't know?

23 A [LYNCH] Yeah, I don't know about that.

24 Q Okay. So you're not sure whether the company is
25 irrevocably committed to the acquisition of that plant?

1 A [LYNCH] I'm not, but I'm not – you know, I'm not in that
2 loop.

3 Q Okay. But it's included in this plan?

4 A [LYNCH] My understanding, it's likely to happen.

5 Q Likely to happen, all right. So 2023, that 540
6 megawatts, what does that represent?

7 A [LYNCH] Another combined-cycle unit.

8 Q Is that to be constructed then?

9 A [LYNCH] Yeah, that'll be a new unit. Yes.

10 Q Going back to the Columbia Energy Center, so you're
11 familiar with that facility; is that right?

12 A [LYNCH] A little bit, yes.

13 Q All right. At present, though, is it your understanding
14 that that is a merchant plant?

15 A [LYNCH] That's my understanding.

16 Q Okay. And that the company has bought power from the
17 Columbia Energy Center in the past?

18 A [LYNCH] Yes.

19 Q Is it currently buying power from the Columbia Energy
20 Center?

21 A [LYNCH] Yeah, so on line 12 there, there's 300
22 megawatts; that's from that facility.

23 Q Okay. All right. So the company is, currently, the
24 Columbia Energy Center's primary customer.

25 A [LYNCH] I think that's correct.

1 Q Is the Columbia Energy Center the only merchant plant
2 that the company buys from?

3 A [LYNCH] I can't – I don't know. I can't say that.

4 Q Okay. So –

5 A [LYNCH] Theirs is the only firm capacity that we have.

6 Q Okay. But you're not aware of whether the company buys
7 power from other merchant plants.

8 A [LYNCH] I know we buy energy in the market; day by day
9 they look for deals. I don't know where they come from.

10 Q So the company does buy energy on the spot market – from
11 the spot market, on a day-to-day basis?

12 A [LYNCH] Maybe I can't say day by day, but, yes, it does –

13 Q Periodically.

14 A [LYNCH] – it purchases – yeah, it purchases power when –

15 Q And –

16 A [LYNCH] – it knows of opportunities.

17 Q – does the company have the capability to buy firm
18 capacity from other merchant plants besides Columbia
19 Energy Center?

20 A [LYNCH] Again, yes, it can.

21 Q And do you recall whether, in last year's IRP, the plan
22 included purchases of merchant power for firm capacity
23 from merchant plants in future years?

24 A [LYNCH] Well, this 300 megawatts is the third of three
25 years, so we would have made – this deal was at '18,

1 '17, '16, so sometime in 2015 we would've arranged for
2 '16, '17, and '18.

3 **Q** Do you – well, do you recall whether last year's IRP
4 included purchases of firm capacity from merchant plants
5 in 2019 or 2020.

6 **A** [LYNCH] I might be able to look.

7 **Q** Okay.

8 **A** [LYNCH] [Indicating.]

9 Well, we had '17, '18, and '19 –

10 **Q** Okay.

11 **A** [LYNCH] – the 300 megawatts. And I guess maybe I'm
12 mistaken about the purchase from the Columbia Energy
13 Center. We probably made it in '16 for '17, '18, and
14 '19. Currently, if we purchase it, then –

15 **Q** Right.

16 **A** [LYNCH] – if we buy the plant, we don't purchase the
17 capacity anymore. I think that's the correct years.

18 **Q** Okay. And on this plan – on this plan, what defines or
19 how do you know how much capacity the company needs to
20 procure or own in each year on this plan?

21 **A** [LYNCH] Right. So you look at the forecast, demand-side
22 management, the existing resources, and then the reserve
23 margin that is needed to supply, to provide the
24 customers reliably.

25 **Q** Okay, okay. So the reserve margin dictates, in part,

1 how much capacity you need to have each year?

2 **A** [LYNCH] Right.

3 **Q** Okay. And the company – under the company's policy, as
4 discussed in your testimony, the company requires a 21
5 percent winter reserve margin?

6 **A** [LYNCH] That's correct.

7 **Q** Okay. Did you consider, in coming up with this plan,
8 whether there are cheaper ways to meet the 21 percent
9 winter reserve margin, besides or other than purchasing
10 or constructing a base-load generation plant?

11 **A** [LYNCH] Well, yeah, I just mentioned the demand-response
12 program, and hopefully that should be cheaper than
13 building a power plant.

14 **Q** So that demand response allowed you to, I guess, to
15 defer construction of a power plant for a few years
16 here?

17 **A** [LYNCH] Something we avoid – if we don't have the demand
18 response, then we'd have to replace that resource with
19 something else.

20 **Q** Okay.

21 **A** [LYNCH] Potentially, a power plant.

22 **Q** Did you consider whether purchasing merchant power or
23 purchasing firm generation would be less expensive than
24 building a new base-load generation plant?

25 **A** [LYNCH] Not in this plan, no.

1 Q So, in your opinion, is this plan – does this plan
2 represent the optimal plan, from the standpoint of cost
3 and reliability?

4 A [LYNCH] It should be close. It's reasonable, certainly.

5 Q Okay. So "reasonable" but not necessarily "optimal"?

6 A [LYNCH] Can we do better.

7 Q Yes, can you do better?

8 A [LYNCH] Well, certainly, before we come in for a
9 certificate of public convenience and necessity, there'd
10 be a lot more work done.

11 Q Certainly. But did you consider – in formulating this
12 plan, did you consider, "Can we do better?" in terms of
13 cost in those future years?

14 A [LYNCH] Oh, yeah, other – but we didn't consider
15 purchasing. We were considering the demand response, as
16 I said, and maybe peakers, a combined-cycle.

17 Q Did you consider purchasing capacity specifically to
18 deal with winter peaks, instead of building base-load
19 generation – sorry – instead of building new generation?

20 A [LYNCH] The thinking is, with the peaks in the
21 wintertime, that we would have a demand-response
22 program, perhaps load control, maybe interruptible
23 customers can sign up for a winter program.
24 Conservation, voltage conservation is another option.
25 There's a lot of things we can try.

1 Q All right. So are those all baked into demand response?

2 A [LYNCH] Yes.

3 Q Thank you. When the company updated the PR2 rates last
4 year, the base case was different, right?

5 A [LYNCH] Yeah.

6 Q And there were different assumptions about the company's
7 generation portfolio?

8 A [LYNCH] Yes, it was a different resource plan.

9 Q Okay. And one of those assumptions was that the V.C.
10 Summer units would be coming on-line; is that right?

11 A [LYNCH] That's correct.

12 Q Okay. And I believe you testified last year that having
13 these units on the system resulted in a reduction in
14 avoided capacity costs for QFs?

15 A [LYNCH] Probably, yes.

16 Q But the assumption about the nuclear units coming on-
17 line has proven not to be true; is that right?

18 A [LYNCH] That's correct.

19 Q Okay. The company – you testified that the company uses
20 the PROSYM computer model to calculate avoided-cost
21 rates under the DRR methodology; is that right?

22 A [LYNCH] PROSYM dispatches the units, so it calculates
23 production cost, the energy.

24 Q Energy costs, that's right.

25 A [LYNCH] Variable cost.

1 Q Right. And for capacity costs, the company just
2 compares the cost of the base case with the cost of the
3 change case, without the need for –

4 A [LYNCH] Yeah, we have a spreadsheet model to calculate
5 the revenue requirements associated – the capital costs
6 associated with any capital investment.

7 Q Okay. But you just use a spreadsheet for that?

8 A [LYNCH] Yes, a spreadsheet.

9 Q So how, with a given set of inputs, how labor-intensive
10 is it to run the PROSYM model to generate an avoided
11 energy cost calculation?

12 A [LYNCH] Well, I wouldn't say it's very difficult.

13 Q Okay.

14 A [LYNCH] We run it ten times with random outages and that
15 sort of thing, but I've got it down to a fine –

16 Q You've done it a couple of times?

17 A [LYNCH] We can get it done pretty quickly.

18 Q And it sounds like running a new calculation of avoided
19 capacity cost is probably not too labor-intensive
20 either; is that right?

21 A [LYNCH] Not too labor-intensive.

22 Q And so, do you use the PROSYM model solely for purposes
23 of updating the PR-1 and PR-2 rates?

24 A [LYNCH] No.

25 Q Okay. What else do you use it for?

1 A [LYNCH] Well, any reason we would need to dispatch the
2 system and look at the results. So the fuel burn, for
3 example, how much coal you're going to need, or expect
4 to need, or gas.

5 Q Under the current PR-2 schedule, the company is required
6 to update the PR-2 at least a twice a year, or more
7 often as needed; is that right?

8 A [LYNCH] I think I'm told that by the legal team. So
9 that might be true. I'm hoping it's not mandatory, or
10 it won't be next year.

11 Q Okay. The current proposal, though, is to update the
12 PR-2 rate, going forward, only on an as-needed basis,
13 instead of twice a year; is that right?

14 A [LYNCH] Yeah, definitely once a year at the fuel
15 hearing, and then if there's some significant change,
16 update it then.

17 Q Okay. I'd like to direct your attention to page seven
18 of your direct testimony. I just want to clarify. At
19 lines 11 and 12, you say that SCE&G also proposes to
20 update – proposes to update its PR-2 rate, going
21 forward, only on an as-needed basis, instead of twice a
22 year?

23 A [LYNCH] Yes, sir.

24 Q Okay. But just to clarify, that doesn't mean that the
25 company wouldn't also update the PR-2 rates in the fuel

1 case?

2 **A** [LYNCH] Well, my understanding is that we would have to
3 come in with an update, or I suppose it could be the
4 exact same rate but we would have to justify it in the
5 hearing. Here's the PR-2 and why is that the PR-2, or
6 the PR-1 rate.

7 **Q** Okay. So your understanding, though, of the company's
8 proposal is that it would update annually in the fuel
9 case, if necessary, and then between times if –

10 **A** [LYNCH] If something happens that warrants a change,
11 yes.

12 **Q** So, and as a rationale for this change, you testified
13 that avoided – I'm looking here at page 19 of your
14 direct testimony. You testified that – starting line
15 ten, but you testified that avoided costs are based on
16 projection of load, resource needs, fossil fuel prices,
17 et cetera, over the IRP planning horizon, and that if
18 avoided costs don't change significantly there's no need
19 for an update. Is that right?

20 **A** [LYNCH] That's – yeah, that's right.

21 **Q** And you testified that SCE&G believes that it's more
22 appropriate to update the PR-2 rate only when there is a
23 significant change in the avoided-cost projections or,
24 more specifically, when the company's long-run avoided
25 costs change significantly. Is that right?

1 A [LYNCH] That's correct.

2 Q Okay. So it's your position that a rate update would be
3 appropriate when the company's long-run avoided costs
4 change?

5 A [LYNCH] So every year at the fuel hearing. I think
6 that's mandatory. And then I can't tell you which
7 decimal place, but I know I ran through some changes
8 here where a fifth decimal point changed, and I'm
9 thinking if something else doesn't change, hopefully,
10 that the management of the company or the Rate
11 Department or somebody will say this is okay to let go.

12 Q So I assume, then, that you think that nothing has
13 happened since the approval of the current PR-2 rate
14 that would've changed the company's long-run avoided
15 costs significantly?

16 A [LYNCH] Nothing has happened in the past couple of
17 weeks, you mean?

18 Q No, since the approval of the currently effective rate
19 that was effective May 2017.

20 A [LYNCH] Oh, yes, things have changed. Yes.

21 Q Okay. What things have changed?

22 A [LYNCH] Well, you mentioned the two nuclear plants are
23 no longer in the resource plan. That would be one.

24 Q Did that change induce the company to update the PR-2
25 rate?

1 A [LYNCH] We're updating it now, with that change.

2 Q Okay. But you didn't – it was not appropriate to update
3 the rate – well, let me ask –

4 A [LYNCH] I'm not sure it was – yeah, so what you're
5 getting at is why didn't we update it in the fall or –
6 that second time? I don't think we were in a position
7 to update it, because you'd need a resource plan, and to
8 get a resource plan you need management to approve it.
9 And there's a lot of – just a lot of uncertainty that
10 we're dealing with also, with the reserve margin. Even
11 last year, we were talking about the risks related to
12 the winter, the needs on the company, so we were working
13 through that, too.

14 Q So when did it become evident that the V.C. Summer units
15 were not going to be part of the company's resource
16 plan?

17 A [LYNCH] I think it was back last summer, July, or –

18 Q July and August?

19 A [LYNCH] – something. I know there's a date certain but
20 I don't know what it is.

21 Q And did the company start revising its resource plan
22 then?

23 A [LYNCH] Shortly after that, certainly, yeah.

24 Q But at that point, the company didn't update its PR-2
25 rate?

1 A [LYNCH] Last summer? No.

2 Q All right. Do you recall that you testified about the
3 need for periodic rate updates in last year's fuel
4 proceeding?

5 A [LYNCH] Yes.

6 Q And do you recall that some of the parties to that
7 proceeding had proposed that the PR-2 rate be updated
8 only annually or only every other year?

9 A [LYNCH] Yes, I recall that.

10 Q And do you recall that you opposed that suggestion?

11 A [LYNCH] Yes.

12 Q Okay. Did you testify last year that biannual updates
13 to the PR-2 rate are reasonable and that they reflect an
14 appropriate balance between the need to update rates and
15 reflect – well, let me just – rather that quote you
16 directly, did you testify that biannual rates were
17 reasonable – were reasonable and necessary?

18 A [LYNCH] I was told that I testified that we should
19 update twice a year, which I regret having said, because
20 I'd rather do it on an as-needed basis. And necessarily
21 updating it when there's no significant change doesn't
22 seem reasonable to me. But part of the concern is there
23 was this concern last year about updating and why we
24 didn't want to wait every two years, for example. I'd
25 be opposed to that, if that was sort of a mandatory

1 condition, because these rates are based on projections
2 that go out 15 years, so a lot can change, and if you
3 don't update the rate frequently, I suppose, or often
4 enough, you could get a –

5 **Q** A stale rate?

6 **A** [LYNCH] You could get a stale rate and maybe a lot of
7 solar facilities on that rate. As more solar comes on,
8 the rate should be changing. A significant amount of
9 more solar – in fact, that's sort of the problem we have
10 now. Now we have 875 megawatts of solar, which is
11 resulting in a lot of lower costs in the avoided costs.

12 **Q** The reason for less frequent updates is that there's too
13 much solar?

14 **A** [LYNCH] The reason for not updating every two years,
15 more frequently than every two years, is there's too
16 many things that can change, and then the company and
17 its customers who ultimately pay whatever the QF rate
18 is, our customers would be too much at risk.

19 **Q** So, last year, you testified that it was appropriate to
20 update the rate at least twice a year; is that right?

21 **A** [LYNCH] Apparently, I did. And I think in there it's,
22 like I say, every summer we'd update the forecast. So
23 come the fall, by September anyway, we would have new
24 forecasts, the new resource plan, and it's a natural
25 thing to recalculate avoided cost.

1 Q And you testified last year that it was critical to keep
2 the PR-2 rate up-to-date and that twice a year was the
3 appropriate interval for that?

4 A [LYNCH] Yeah, but hopefully – to be understood, now,
5 when I say it's critical to update it, if there's a
6 significant change. If there's no change or if the
7 change is in the fifth decimal place, well, then it's
8 not so critical, if you see what I'm getting at. And so
9 I thought that's what I was testifying to last year, but
10 that would be my statement now, what I believe is
11 correct.

12 Q Okay. So I guess what I'm not understanding is why it
13 was critical last year to update twice a year and why
14 it's not critical now to update twice a year.

15 A [LYNCH] Well, because we're finding that if it's not a
16 significant change – if there's not a significant
17 change, can it be critical to update it in the fall?

18 Q And you don't think that avoided-cost rates changed
19 significantly between, say, May 2017 and November 2017?
20 May 2017 was when the last PR-2 rate schedule was
21 updated?

22 A [LYNCH] Well, obviously, there was a significant change
23 in the offering, because so much has changed with the
24 nuclear plant, new resource plan, a lot of things are
25 different. So there is a significant change, but the

1 company wasn't in the position to calculate those
2 changes.

3 Q So it would've been impossible for the company to
4 perform an avoided-cost calculation?

5 A [LYNCH] Yeah, close to impossible – yeah, close to
6 impossible.

7 Q All right. Well, but the company had an avoided cost,
8 right? I mean, it's a real thing, isn't it? Did the
9 avoided cost cease to exist during those times or did it
10 just –

11 A [LYNCH] Well, you have – the avoided costs are the
12 published rates that the Commission approves, so we
13 always have the avoided – it's always there.

14 Q Okay. Do you recall testifying last year that, if there
15 was – we had a little discussion last year about what
16 kind of event would justify a rate update more
17 frequently than twice a year. I probably remember –

18 A [LYNCH] I'm sure we talked about it.

19 Q Okay.

20 A [LYNCH] I don't remember specifically.

21 Q Yeah, and do you recall that you said that if there was
22 a significant chunk of capacity that was going to be
23 affected, and it would have a significant revenue
24 impact, and it would have an impact on customers, that
25 it would be appropriate to update the rates? Is that

1 consistent with –

2 A [LYNCH] That sounds right.

3 Q Okay. And did the failure of the V.C. Summer project
4 have a significant impact on the company's capacity
5 needs?

6 A [LYNCH] Yes.

7 Q And did it have a significant revenue impact?

8 A [LYNCH] Well, yes, but due to avoided costs. It would
9 change the avoided costs.

10 Q Okay. How do you think it would've changed the avoided
11 costs?

12 A [LYNCH] Well, if you compare the avoided energy cost we
13 filed in this case to what was approved by the
14 Commission last year, there's the difference.

15 Q So you think that if you had just updated the PR-2 rate
16 only to reflect the change in the company's expansion
17 plan, based on – the changes to the expansion plan,
18 based on the failure of the V.C. Summer plants, that
19 avoided-cost rates would've been lower?

20 A [LYNCH] Yeah, no, I'm saying that the company did update
21 its avoided costs, based on new circumstances, one big
22 one being that the nuclear plants were no longer going
23 to be constructed. So we did update it and filed it in
24 this hearing. Those are the updates that we have.

25 Q But you combine that update – well, the change to the

1 generation plan was not the only change in the approach
2 that was taken to calculating the PR-2 rate; is that
3 right?

4 **A** [LYNCH] Well, other things – other conditions changed.
5 For example, 875 megawatts of solar that we didn't have
6 last year. That affects the value, more solar on the
7 system. So that's another part of the significant
8 change that comes into play. So there's a lot of –

9 **Q** Okay.

10 **A** [LYNCH] – a lot of things.

11 **Q** But the company opted not to update the PR-2 rate after
12 the failure of the V.C. Summer project was evident?

13 **MR. MUSTIAN:** Mr. Chairman, I would object on
14 two grounds. One is –

15 **CHAIRMAN WHITFIELD:** Mr. Mustian, can you get
16 to a microphone, please, sir?

17 **MR. MUSTIAN:** I apologize. Yes [indicating].

18 Mr. Chairman, on two grounds, just briefly.
19 One is this line of questioning has been asked and
20 answered many times by Dr. Lynch. In addition,
21 this has been an issue that has been presented to
22 the Commission. It was a request made by the
23 company that has been granted by the Commission,
24 and the Commission has now ruled on this issue
25 several times, between the Petition that was filed

1 by CCL/SACE, the Motion to Bifurcate by the Solar
2 Business Alliance. This issue has been addressed,
3 and the company believes it's been put to bed and
4 that this line of questioning is, therefore,
5 irrelevant.

6 MR. WHITT: Mr. Chairman –

7 CHAIRMAN WHITFIELD: Mr. Whitt?

8 MR. WHITT: – since Mr. Snowden is not
9 admitted in South Carolina, I'll respond to that.
10 It's cross-examination, Mr. Chairman. In South
11 Carolina, we have wide latitude of cross-
12 examination. Just because the company doesn't like
13 where it's going, that's not a ground to object to
14 cross-examination. We have wide latitude. He's
15 referenced things that this witness said last year.
16 They've referenced things he said last year, and
17 he's just bringing it forward for discussion today.
18 And I would think this Commission would want to
19 hear as much as they possibly could about what has
20 occurred in the last year, given the abandonment of
21 the two nuclear plants, for example, that Attorney
22 Snowden is referencing. So, it's cross-
23 examination.

24 CHAIRMAN WHITFIELD: Mr. Mustian?

25 MR. MUSTIAN: Mr. Chairman, I'll respond. The

1 Rules of Evidence are very clear. They say that
2 questioning has to be – and the evidence that's to
3 be elicited has to be reliable, probative, and
4 relevant to the issue in the proceeding. To the
5 extent that Mr. Snowden is asking questions with
6 respect to comparisons of what Dr. Lynch said last
7 year versus this year, that's one thing. To the
8 extent that we're going into a rehash and a re-
9 argument of the waiver that was granted by this
10 Commission and the reasoning for the request for
11 the waiver not to update the PR-2 rate in December
12 of 2017, that issue has been ruled upon by this
13 Commission and, therefore, it is no longer
14 relevant. So under the Rules of Evidence, this
15 line of questioning is inappropriate, regardless of
16 whether or not cross-examination has wide latitude
17 in South Carolina.

18 MR. SNOWDEN: Mr. Chairman, if I may? There
19 is a pending request by the company to change the
20 frequency with which the PR-2 rate should be
21 updated, so I would say, certainly, this is – this
22 line of questioning is relevant to that change, if
23 nothing else.

24 MR. WHITT: Mr. Chairman, when the waiver was
25 granted, it was stated, then, generically – not

1 specifically – that these issues would be covered
2 at this hearing. So it would be a great
3 disadvantage for us to say that they wanted to talk
4 to these issues in the fuel case, and now they're
5 going to be restricted.

6 As far as the testimony being reliable,
7 Attorney Snowden is reading from the prior
8 testimony of the witness. I don't see how it could
9 be any more reliable than reading from the
10 testimony. And, certainly, the waiver's before
11 this Commission.

12 **MR. SNOWDEN:** I will try to be brief.

13 **CHAIRMAN WHITFIELD:** And I do need to hear Mr.
14 Mustian again, but go ahead, Mr. Snowden. I do
15 need to hear Mr. Mustian. You have another comment
16 towards this?

17 **MR. SNOWDEN:** I just said I will try to be
18 brief.

19 **CHAIRMAN WHITFIELD:** And we do – I was going
20 to head in that direction. But let me hear from
21 Mr. Mustian again.

22 **MR. MUSTIAN:** Mr. Chairman, I think I've made
23 our arguments, so I wouldn't have anything further
24 to add.

25 **CHAIRMAN WHITFIELD:** Okay. I tell you, at

1 this time – I don't know how much longer you have,
2 Mr. Snowden. Any idea how much longer you have?

3 **MR. SNOWDEN:** I've got a little while to go.

4 **CHAIRMAN WHITFIELD:** You do have a little
5 while. Okay. Well, at this time, I'm going to
6 make an announcement. We are going to stop today
7 at 5:45. If there are any witnesses that can't be
8 here – if we don't finish today, if there are any
9 witnesses that can't be here tomorrow, we're going
10 to take a brief break right now and I need any
11 witnesses that think they have a problem about
12 possibly being here tomorrow, should it come to
13 that, to please see one of our Commission Staff
14 members or our attorney, and we'll address that
15 when we come back. But for now, we're going to
16 take about a 10-minute break.

17 [WHEREUPON, a recess was taken from 3:10
18 to 3:40 p.m.]

19 **CHAIRMAN WHITFIELD:** Please be seated. I'll
20 call this hearing back to order and we will resume
21 with the company's panel. I believe we had an
22 objection here by Mr. Mustian.

23 **MR. WHITT:** Mr. Chairman, SBA is willing to
24 move on past those waiver questions.

25 **CHAIRMAN WHITFIELD:** Okay. Thank you, Mr.

1 Whitt. I guess we'll resume – you're saying that –

2 MR. WHITT: He covered part of the questions,
3 and he had some more to go on the waiver, but he's
4 going to skip past that and move on.

5 CHAIRMAN WHITFIELD: Well, that's –

6 MR. WHITT: Yeah, he has some that's in the
7 area, but not the waiver that was objected to, so
8 he'll move on.

9 CHAIRMAN WHITFIELD: Well, that's exactly
10 where I was going to go. I was going to overrule
11 Mr. Mustian and ask Mr. Snowden to move on.

12 MR. WHITT: Okay.

13 CHAIRMAN WHITFIELD: And if he's willing to do
14 that, let's resume –

15 MR. WHITT: Yeah.

16 CHAIRMAN WHITFIELD: – and, let's see, Mr.
17 Snowden, if you'll come back, and let's see if we
18 can't move on and move ahead.

19 MR. SNOWDEN: Mr. Chairman, and to be clear, I
20 have a handful – I'm not going to repeat any
21 questions that I had previously asked, and I cut a
22 big chunk, in the interest of moving forward. I
23 have a couple of questions on the rate update, if I
24 may submit those and we'll see if Mr. Mustian – is
25 that all right? I've got just a minute or two,

1 following up on this topic.

2 CHAIRMAN WHITFIELD: Well, let's get moving.

3 MR. SNOWDEN: Okay. Yes, sir.

4 BY MR. SNOWDEN:

5 Q Dr. Lynch, you testified before the break that the
6 company did not update the PR-2 rate between May 2017
7 and now because it was not possible to do a rate update?
8 Is that –

9 A [LYNCH] That's correct, yes.

10 Q And that was because there was not a generation plan in
11 place?

12 A [LYNCH] Yeah, there was a lot of – yes.

13 Q Okay.

14 A [LYNCH] That's probably –

15 Q But you also testified that a generation plan is just a
16 plan and doesn't actually commit the company to
17 anything; is that right?

18 A [LYNCH] That's correct.

19 Q Okay. You also testified that management would have to
20 – if I understood correctly, you testified that someone
21 in management would have to approve the generation plan
22 in order for it to be used as a basis for calculating
23 avoided costs? Is that right?

24 A [LYNCH] Well, typically, before a plan becomes official
25 – like if you file it with the IRP, it's sort of an

1 official plan – we would want someone – I would want
2 somebody in management to sign off on it.

3 **Q** But in last year's rate proceeding, weren't your
4 recalculations based on a slight variation from the IRP
5 that was filed? I believe there was some – if I recall
6 correctly, and you can correct me, do you recall that
7 there were a couple of PPAs that had fallen through, I
8 think, and so the –

9 **A** [LYNCH] Right, so the testimony was filed. I think it
10 was like February 21st, something like that. IRP filed
11 February 28th. And in that week, we were informed that
12 two solar – I think it was 40 megawatts, two 20-megawatt
13 plants, if I recall right, that they had dropped out,
14 and so we took them out of the resource plan.

15 **Q** So is there some kind of internal rule in the company
16 that you have to have a management-approved generation
17 plan in order to calculate avoided-cost rates?

18 **A** [LYNCH] I don't think it's written down anyplace, but –

19 **Q** Well, whose decision was it that you can't – whose call
20 is it that you can't update the rates because there's
21 not a generation plan?

22 **A** [LYNCH] Well, I make sure my boss – I tell her what
23 we're going to do.

24 **Q** And after the failure of the V.C. Summer plants, you did
25 know that – you didn't know what generating resources

1 would be used to replace those plants; is that right?

2 A [LYNCH] That's correct.

3 Q Okay. But you did know those plants would not be part
4 of the resource plan?

5 A [LYNCH] That's correct.

6 Q Did the company perform any kind of internal calculation
7 of avoided-cost rates after V.C. Summer fell out of the
8 resource plan?

9 A [LYNCH] I remember we had preliminary plans we were
10 looking at, and we were making estimates if there was –
11 if the plans moved – if the resource plan changed, it
12 was like a 100-megawatt purchase round-the-clock, I
13 mean, we were looking at stuff to see what would happen.

14 Q So you did do some internal analyses of avoided costs?

15 A [LYNCH] Yeah – well, preliminary, without the resource
16 plan, so it was sort of unofficial, trying to get a feel
17 for what it all meant.

18 Q Okay. And do you recall what the impact to avoided-cost
19 rates was, or what the results of the preliminar –

20 A [LYNCH] The avoided capacity – I don't remember what the
21 plan was, preliminary, but sort of in the neighborhood
22 of \$40 a kW-year, is what I remember. Something like
23 that.

24 Q Okay. So it did change the avoided capacity rates?

25 A [LYNCH] What changed it?

1 Q Well, your preliminary analysis showed that the falling
2 out of the V.C. Summer plants from the resource plan did
3 have an impact on avoided capacity rates?

4 A [LYNCH] I'd have to say no. What affects the avoided
5 capacity cost is going to be the purchase from the
6 qualifying facility. And if the qualifying facility is
7 a solar plant, it won't affect the expansion plan, so
8 the avoided cost is going to be zero. If it was a 100-
9 megawatt purchase round-the-clock, another 100-megawatt
10 unit, or something, it would affect the expansion plan
11 and affect the units, and there would be an avoided
12 cost, a positive avoided capacity cost.

13 Q Okay. So, did sort of an internal recalculation of the
14 PR-2 —

15 A [LYNCH] We were looking at it, getting ready, yes.
16 Yeah.

17 Q Okay. But you didn't actually file that with the
18 Commission?

19 A [LYNCH] Well, we were just looking at it. No, there's
20 nothing to be filed. There's no plan. We couldn't file
21 it anyway.

22 Q And did you produce — are there any documents that
23 reflect those analyses that were produced to ORS or
24 other parties in this proceeding?

25 A [LYNCH] This was all internal staff. No, so there's no

1 documents. I don't know – to my knowledge, I don't
2 think there's anything.

3 **Q** Okay. One final question. So you did perform a sort of
4 rough calculation at that time?

5 **A** [LYNCH] Yeah.

6 **Q** Wouldn't you agree that the results of that analysis
7 with respect to avoided-cost rates would have been more
8 accurate than the PR-2 rates that were on the books as
9 of May 2017?

10 **A** [LYNCH] Yeah, I wouldn't say that. And then another
11 thing, I'd also – I'd hate to – I don't like calling
12 them avoided costs, either, because that suggests some
13 official calculation is what you're going to avoid,
14 you're almost ready to put in a rate, or something. And
15 this was not. We were looking at the model to see what
16 potentially could happen.

17 **Q** So you don't think those estimates of avoided costs
18 would be more accurate than the PR-2 rate that was
19 approved that assumed the –

20 **A** [LYNCH] I don't think so. I don't think they're
21 relevant to anything, either.

22 **Q** You don't think they're relevant.

23 **A** [LYNCH] No, sir.

24 **Q** In your testimony, you discuss the company's proposal to
25 limit the availability of the PR-2 rate to solar QFs

1 only; is that right?

2 **A** [LYNCH] That's correct.

3 **Q** What kind of QFs are eligible for the current PR-2 rate?

4 **A** [LYNCH] Any qualifying facility, and I believe it's
5 limited – you have to be greater than 100 kW and less
6 than 80 megawatts.

7 **Q** So that would include wind or biomass or cogeneration
8 units?

9 **A** [LYNCH] Yeah, any qualifying – any facility that meets
10 the PURPA definition of qualifying facility.

11 **Q** And the Commission has previously concluded that it's
12 appropriate to offer the same rate to all kinds of QFs;
13 is that right? All of –

14 **A** [LYNCH] I don't know if – well, they approved a PR rate
15 from – a PR-2 rate from last year, and the PR-1 rate,
16 too.

17 **Q** And that PR-2 rate that was approved last year is
18 available both to solar QFs –

19 **A** [LYNCH] And non-solar, that's correct, yes.

20 **Q** Does the company's decision to offer the PR-2 rate only
21 to solar QFs have implications for the calculation of
22 avoided-cost rates, for the solar QFs?

23 **A** [LYNCH] Not parti- – I wouldn't think so, no.

24 **Q** So you do not think that the decision to offer the PR-2
25 rate only to solar QFs has an impact on the calculation

1 of avoided-cost rates?

2 A [LYNCH] The use of a solar profile for a solar QF to
3 calculate the avoided capacity cost affects – if you're
4 assuming a solar profile, then that has implications for
5 how, you know, what the avoided costs are.

6 Q But you wouldn't use a solar profile for calculating
7 avoided costs for a non-solar QF, would you?

8 A [LYNCH] No.

9 Q So that use of that solar profile does have implications
10 both for avoided energy costs and avoided capacity
11 costs?

12 A [LYNCH] Oh, for – yeah, for solar? Yes.

13 Q Okay. Are there any other implications besides the
14 impact on avoided-cost rates, for solar QFs, of using or
15 having a solar-only rate?

16 A [LYNCH] Well, if you postulate a different QF with
17 different load characteristics and different profiles,
18 presumably, you would get a different avoided-cost
19 calculation. It'd have a different value on the system.

20 Q Okay.

21 A [LYNCH] And the solar has the value that we're putting
22 forth –

23 Q Okay. So a non-solar QF that requested a PPA from the
24 company would have to get a sort of calculated rate; is
25 that right?

1 A [LYNCH] If one came, we would negotiate with it. I
2 mean, we went 35 years without these PR-2 rates, you
3 know, with the plan to negotiate with any non-solar that
4 showed up.

5 Q Okay.

6 A [LYNCH] And that worked fine. There weren't many that
7 showed up; there was only one.

8 Q And you would calculate those rates, presumably, using
9 the methodologies that were used to calculate the
10 current PR-2 rates?

11 A [LYNCH] Well, depending on the load characteristics and
12 the size and that sort of thing of this QF that's non-
13 solar, we would try to calculate what's the avoided cost
14 related to that particular contract, and then somebody
15 would negotiate a deal with the party.

16 Q In preparing your testimony for this hearing, did you
17 ever perform an analysis of what current avoided-cost
18 rates would be for non-solar QFs above 100 kW?

19 A [LYNCH] No.

20 Q The company –

21 A [LYNCH] I should say, but the only thing is the energy,
22 we did. Because I felt we had to justify moving away
23 from a 100-megawatt profile in every hour, because we
24 had argued – I remember arguing about that for two
25 years. The company wanted one rate; that was the ideal.

1 But, again, with so much solar on the system now,
2 additional solar, you'd have to – you really have to use
3 a solar profile to get the true avoided costs for more
4 solar.

5 Q How much solar is on SCE&G's system right now?

6 A [LYNCH] Last time I – I think we have about 300
7 megawatts – 301 megawatts, or something like that. And
8 I think that includes behind the energy meter. It's
9 probably 200 utility-scale stuff.

10 Q Okay. And about what percentage of the generation
11 portfolio is that?

12 A [LYNCH] I remember the 865 is something like 17 percent,
13 or something. I don't know if – I'd have to calculate
14 it.

15 Q You don't know what the current –

16 A [LYNCH] Percentage is, yeah.

17 Q You currently don't have that?

18 A [LYNCH] But I will add – and you probably know this –
19 that CCL or SACE did a study, just came out recently,
20 and I notice you guys had in the Southeast who had the
21 most solar, and we were pegged as number two. Duke
22 Energy Progress – Duke Energy's project was first, in
23 terms of kW per customer or watts per customer,
24 something like that? Are you familiar? And we were
25 number two, then –

1 Q That's great.

2 A [LYNCH] – Duke Energy Carolina. So whatever those
3 ratios are, or percentages, I don't have them off the
4 top of my head, but –

5 Q The State overall –

6 A – [LYNCH] – it's significant.

7 Q Okay.

8 A [LYNCH] On our system, it's significant.

9 Q Okay. So the company is also proposing to calculate
10 avoided energy costs and capacity costs based on this
11 generic 100-megawatt solar profile; is that right?

12 A [LYNCH] Yes.

13 Q Okay.

14 A [LYNCH] Yeah.

15 Q And can you explain just what a 100-megawatt solar
16 profile – what that means?

17 A [LYNCH] Yeah. Well, we have the solar facilities on our
18 system now, so we can take a solar profile where we have
19 8760 hours of operation, and then when we put that into
20 PROSYM, the way our model did it was they calculated,
21 so, hourly output by the solar facility. So it's actual
22 loads. And then they calculated – I think they have to
23 put in an average week by month, so a lot of smoothing
24 and averaging gets in. And that's what was put into the
25 PROSYM model.

1 Q So the solar profile is sort of a composite of all the
2 solar –

3 A [LYNCH] It's actually one plant, but it's a composite of
4 hours.

5 Q Okay.

6 A [LYNCH] There's only one farm that we used, because
7 that's all we had.

8 Q So you used a single farm to generate a solar profile
9 that –

10 A [LYNCH] Yes.

11 Q – finds the rates for all the solar.

12 A [LYNCH] Right. That's because we only had – we really
13 only had one on the system. In this study we did, or I
14 did as Exhibit -3, we used two profiles. We had one
15 from North Carolina that –

16 Q So you chose a single project in North Carolina?

17 A [LYNCH] It was a single project, well, and then we had
18 our project in South Carolina, and no material
19 difference in the results. That was sort of part of the
20 study, to see what impact there would be if we had
21 different profiles.

22 Q How do you know that the solar profile based on – that
23 the profile of this one farm is representative of the
24 actual output of other solar farms?

25 A [LYNCH] Yeah. I suspect they're very close, because it

1 all follows the sun. I mean, they're all a little bit
2 different, if they're tracking the axis and that sort of
3 thing, so I'm sure there's a difference. But in terms
4 of the avoided energy costs, using this profile is
5 better than what we were doing before with the 100
6 megawatts every hour.

7 MR. SNOWDEN: Okay. I would like to move to
8 introduce an exhibit. This has been previously
9 circulated to the Commission. It's the document
10 that is marked "Rebuttal Testimony of Joseph M.
11 Lynch on behalf of South Carolina Electric & Gas
12 Company," in Docket No. 2017-2-E. And this is Dr.
13 Lynch's rebuttal testimony from last year's fuel
14 proceeding.

15 MR. WHITT: Ben, you're going to get those to
16 the other parties.

17 MR. SNOWDEN: Yes.

18 MR. WHITT: There are copies coming.

19 [Document distributed]

20 CHAIRMAN WHITFIELD: Mr. Snowden, are you
21 asking for this to be marked for identification?

22 MR. SNOWDEN: Yes, sir.

23 CHAIRMAN WHITFIELD: Okay. Mr. Mustian?

24 MR. MUSTIAN: Mr. Chairman, I didn't know if
25 you were getting ready to rule on whether or not to

1 introduce that. We have no reason to believe this
2 is not an accurate reflection of what Dr. Lynch
3 testified to last year, that it's actually what is
4 reflected in the proceeding from last year, so just
5 subject to that caveat and subject to check –

6 **CHAIRMAN WHITFIELD:** Subject to check?

7 **MR. MUSTIAN:** – we have no objection.

8 **CHAIRMAN WHITFIELD:** All right. Thank you,
9 Mr. Mustian.

10 In that case, Mr. Snowden, we will enter that
11 in as Hearing Exhibit No. 7. That's Dr. Lynch's
12 rebuttal testimony from the fuel case a year ago,
13 2017-2-E.

14 [WHEREUPON, Hearing Exhibit No. 7 was
15 marked and received in evidence.]

16 **MR. SNOWDEN:** Okay. Thank you, Mr. Chairman.

17 **BY MR. SNOWDEN:**

18 **Q** Dr. Lynch, do you recognizes this document as your
19 rebuttal testimony from last year's fuel proceeding?

20 **A** [LYNCH] I recognize my name – yes, I do.

21 **Q** I would ask you to turn to page two of this document,
22 starting with line nine. It says, "Dr. Vitolo suggests
23 that SCE&G should use a 100-megawatt solar profile when
24 calculating avoided energy costs. Do you agree with his
25 suggestion?" And what was your answer to that question

1 as recorded in this testimony?

2 A [LYNCH] It says, "No." No.

3 Q No, okay.

4 A [LYNCH] Because last year we didn't have 875 megawatts
5 of solar on the system. That's part of the problem that
6 we're talking about today.

7 Q Do you recall what your rationale was last year for
8 rejecting the suggestion that the company use a 100-
9 megawatt solar profile?

10 A [LYNCH] Yes.

11 Q What was that?

12 A [LYNCH] I thought we could have a PR rate that all QFs
13 could have a single rate that would accurately provide
14 avoided cost to every QF that showed up. That was the
15 thinking last year, when I didn't realize there was
16 going to be this explosion of solar on the system. I
17 find that, since then, that what I hoped for – which I
18 thought was a rational way of approaching it last year –
19 wouldn't work now, because of the magnitude of the
20 increase in solar.

21 Q Did you also testify last year that the use of a 100-
22 megawatt solar profile was inappropriate because
23 generation profiles can be significantly different,
24 depending on the characteristics of the facility?

25 A [LYNCH] Yes.

1 Q Okay. And did you testify that a solar system that can
2 track the sun likely will have a different profile from
3 the solar array without this capability?

4 A [LYNCH] Yes.

5 Q Okay. And did you testify that individual profiles also
6 can depend on whether and how solar panels are tilted or
7 oriented, the efficiency of each panel, and the
8 properties of the inverter?

9 A [LYNCH] Yeah, that was a concern. And that was one
10 reason – that's one reason why, when we did the study on
11 profiles, we used the North Carolina profile and the
12 South Carolina profile, to see what the difference is.

13 Q But you –

14 A [LYNCH] Both –

15 Q – testified last year that it would be inaccurate to use
16 a single generic –

17 A [LYNCH] Yeah, I was worried about it. But in the study
18 we did, we ran ten different scenarios with random
19 seeds, to get ten different estimates of avoided cost,
20 for each solar profile.

21 Q But those random seeds – if I recall correctly, those
22 random seeds correspond to different outages on the
23 system, didn't they?

24 A [LYNCH] That's correct.

25 Q Okay, not to different solar generating – different –

1 A [LYNCH] The difference would be –

2 Q – generation on the system.

3 A [LYNCH] – it'd be ten different estimates of what the
4 avoided costs would be.

5 Q Yeah, but you didn't vary the solar profile in those ten
6 different runs.

7 A [LYNCH] No. No.

8 Q And you used a – so, a single South Carolina solar farm
9 was taken to be – let me back up. You think it was
10 adequate, the profile of a single South Carolina solar
11 farm was adequate, to calculate the avoided energy and
12 capacity costs of all solar facilities in South
13 Carolina?

14 A [LYNCH] It's certainly better than using 100 megawatts
15 in every hour. Like I said, we used North Carolina and
16 South Carolina, and the results were very close. You
17 get almost the same avoided cost, I believe. I mean,
18 I –

19 Q Thank you.

20 A [LYNCH] – think we did. And, of course, another thing
21 to remember, as we get more solar on the system and have
22 more options, we'll update everything with more solar
23 profiles where we have the actual data.

24 Q Okay, thank you. So just to recap, if the PR-2 tariff
25 was not solar specific, you would not have been able to

1 use – it would not have been appropriate to use this
2 methodology for calculating avoided costs; is that
3 right?

4 A [LYNCH] I'm –

5 Q Want me to repeat that?

6 A [LYNCH] Yeah, please.

7 Q Okay. If the PR-2 tariff wasn't specific to solar
8 facilities, as proposed by the Commission^[sic], it wouldn't
9 be appropriate to use this solar profile to calculate
10 avoided costs, would it?

11 A [LYNCH] If the QF is not a solar QF, then it probably
12 shouldn't be paid based on the PR-2 rate, which is
13 designed for a solar QF.

14 Q And if a solar facility didn't follow this generation –
15 it didn't approximate this generation profile, would it
16 be appropriate to use this generation profile to
17 calculate avoided-cost rates from that QF?

18 A [LYNCH] I'm sorry, I don't – I'm not following.

19 Q If the actual output of a solar facility didn't match
20 the profile that you used in your calculations –

21 A [LYNCH] Yeah.

22 Q – it wouldn't be appropriate to use that profile to
23 calculate rates for that other QF, would it?

24 A [LYNCH] Oh, I think it would be appropriate. I disagree
25 with you. And part of what we did – and I was just

1 trying to explain why I thought this was a good idea
2 that, you know, the engineers have – is we took an
3 average week. So you're taking several weeks of the
4 solar profile, the actual solar profile, averaging it
5 over hours, so you get a typical profile for the month,
6 and –

7 **Q** But, again, –

8 **A** [LYNCH] – it's –

9 **Q** – it's – I'm sorry.

10 **A** [LYNCH] So there's no – it's not really any kind of
11 random stuff going on with that specific profile; a lot
12 of it got smoothed out. And then, of course, the other
13 thing is I suspect – and this is just something from
14 rate design we've heard all over the years, is that, in
15 theory, every customer should have his own rate, but
16 it's just – you can't just do it, because everyone has a
17 different profile. So every solar farm, presumably, has
18 a different cost on the system, but we have to, because
19 there are so many, put one rate or something like that
20 just to make this thing manageable.

21 **Q** How did you choose the solar farm to use for that
22 profile?

23 **A** [LYNCH] It was the only thing that we had, you know, a
24 whole year of data –

25 **Q** Okay.

1 A [LYNCH] – for.

2 Q So, Dr. Lynch, you're aware that some currently
3 operating solar projects in other states are being
4 combined with battery storage systems that would allow
5 those facilities to change the times that they're
6 putting power on the grid every day?

7 A [LYNCH] I know there's research and whatnot going on
8 with solar and batteries, yes.

9 Q Okay. And why would they want to do that?

10 A [LYNCH] Why would the solar farm want to put a battery –

11 Q Yeah.

12 A [LYNCH] – on? I'm sure they're hoping that they can
13 make their product more valuable.

14 Q Mr. Raftery, I might call on you for a minute, if you
15 don't mind?

16 A [RAFTERY] Yeah, that'd be fine.

17 Q In your direct testimony – and I'd direct you to page 13
18 of your direct testimony – you say that – let me give
19 you a minute, sorry.

20 A [RAFTERY] I'm there.

21 Q Okay. So you say that battery energy storage systems
22 could provide the ability to store the currently non-
23 dispatchable non-schedulable solar power production when
24 the grid does not require the excess energy and then re-
25 dispatch that power from the batteries when needed most

1 across the grid; is that right?

2 A [RAFTERY] That is what I put in my testimony, yes.

3 Q Okay. And so is that another way of saying that the
4 output of a solar-plus-storage facility can be changed
5 so that it might not match the sort of generic solar
6 profile?

7 A [RAFTERY] Yes, it could, with energy storage.

8 Q And, Dr. Lynch, do you disagree with anything that Mr.
9 Raftery said about storage?

10 A [LYNCH] The basic point was that a solar farm with the
11 battery could change its profile?

12 Q Uh-huh.

13 A [LYNCH] Yeah, I agree that's possible.

14 Q Okay. So, does this mean that the output of a solar
15 facility that's equipped with a storage system with a
16 battery wouldn't necessarily resemble the generic solar
17 profile that you used to calculate avoided-cost rates?

18 A [LYNCH] Yeah, so if a solar farm with a battery came to
19 the company and wanted a PPA, we would negotiate it.

20 Q Okay.

21 A [LYNCH] So the PR-2 rate, I don't think would be – maybe
22 it might not be a valid rate for a solar-plus-battery.
23 Perhaps. I mean, it depends – for example, who
24 dispatches the battery, is sort of an issue in my mind.

25 Q Okay. Dr. Lynch, I'd like to refer you to – this is one

1 of your exhibits. It's part of Exhibit 5, but it's
2 JML-3. This is your Avoided Energy Cost Method Study
3 for solar QFs.

4 A [LYNCH] Last year or this year?

5 Q Oh, sorry. This year. I don't have any exhibits from
6 last year.

7 A [LYNCH] And, I'm sorry, Exhibit -3?

8 Q It's JML-3. It's part of Exhibit 5.

9 A [LYNCH] JML-3 okay.

10 Q So this is the Avoided Energy Cost Method Study for
11 solar QFs. Dr. Lynch, did you prepare this study?

12 A [LYNCH] Well, yes. Me and my team, yes.

13 Q So you supervised it.

14 A [LYNCH] Supervised, yes. Yes.

15 Q And what was the purpose of this study?

16 A [LYNCH] Well, it was – since we had spent two fuel
17 hearings arguing that the company prefers to have a
18 single PR rate based on a 100-megawatt profile to get
19 the difference in revenue requirements, I thought we
20 needed some kind of a study or proof or demonstration
21 that it is necessary, when you're calculating avoided
22 costs, avoided energy costs, for a solar QF, that you
23 have to use a solar profile now – again, because of the
24 magnitude of solar on the system.

25 Q And if you'd say, briefly, what conclusions do you draw

1 in this study?

2 **A** [LYNCH] Well, in order to get a valid price, a good
3 price, the avoided cost for the solar – incremental
4 solar above 865 megawatts – it's important to use a
5 solar profile. This is sort of the conclusion.

6 **Q** So you discuss certain operational issues associated
7 with solar QFs in this study; is that right?

8 **A** [LYNCH] Yeah, somewhere I do, yes.

9 **Q** And as described in here, one of those operational
10 issues is what's called a low-load problem, where the
11 load gets so low that some generators must be taken off-
12 line because they can't operate at an output below a
13 certain minimum?

14 **A** [LYNCH] Yeah, potentially, yes, that's a problem.

15 **Q** Okay. And the other operational issue you discussed in
16 here is the ramping rate; is that right?

17 **A** [LYNCH] Ramping is a problem, yeah.

18 **Q** Okay. And what does that mean?

19 **A** [LYNCH] Well, the company has to follow the load. And
20 if you have a lot of solar on the system, it changes the
21 shape of the profile that the rest of the system has to
22 follow. It has that, what they call, a duck curve, so a
23 steep ramping down to the minimum point and then a fast
24 ramping up in the afternoon, and our dispatchers tell me
25 that part of the problem is that you need the capacity

1 on-line in the morning for the morning peak, and then
2 you've got to do something – when you have that minimum
3 load, you have to do something with the generators.
4 Some of them, there's a limit to how far they can go
5 down. But you know you're going to need the capacity in
6 the afternoon, after it comes back up.

7 **Q** Dr. Lynch, where in this study or in your testimony do
8 you discuss how these operational issues are reflected
9 in your rate calculations?

10 **A** [LYNCH] Oh, I might have to find the spot. But the
11 purpose of the study and what the study actually does
12 is, I think, is make a calculation of what those
13 dispatching costs are. So PROSYM, if you subtract 100
14 megawatt-hours in every hour – and this is the purpose
15 of the study – you subtract 100 megawatt-hours, you get
16 one number as an avoided cost for that QF, but if you
17 put a solar profile in, you get something less. Four
18 dollars and eighty-five cents [\$4.85], I think, is the
19 number, or something of that sort.

20 **Q** I see some discussion in the study of operational issues
21 and then I see some results in terms of pricing. But I
22 guess what I don't see and hear – and if you can point
23 me to it, that would be great – is how these operational
24 issues actually are connected to a change in the cost
25 calculations.

1 A [LYNCH] There's a point in my testimony where I mention
2 the \$4.85?

3 Q Uh-huh?

4 A [LYNCH] Does that not say part of the decision?

5 Q You mention that the results are different for the
6 different profiles, but what I don't see is –

7 A [LYNCH] But I don't, in part, say that that's part of
8 the problem with the dispatch? Because I – yeah, I do,
9 because there's even – I was citing to – I'm sure I made
10 a point of this in the testimony, is that I was also a
11 little bit surprised that the PROSYM model was picking
12 this stuff up, these variable integration costs and the
13 problems with the dispatch. The PROSYM model – because
14 when you run a PROSYM model, PROSYM knows all the loads
15 and all what's going to happen; it dispatches and knows
16 everything. Whereas, in real life, our dispatchers
17 don't know what's going to happen tomorrow. They have
18 forecasts, the weather changes, this and that, so that
19 these integration costs, in reality, on the system, are
20 going to have to be higher than what –

21 Q So these –

22 A [LYNCH] – PROSYM is estimating.

23 Q – these operational issues affect the output of PROSYM?
24 Is that fair to say?

25 A [LYNCH] Well, it affected – we're talking about the

1 production costs and avoided costs. Yes, they affect
2 those.

3 **Q** Okay. Do you discuss in the study or in your testimony
4 how these operational issues are currently impacting the
5 operation of the company's system?

6 **A** [LYNCH] Oh, the actual – I don't think so, no.

7 **Q** Okay. Is the company experiencing low-load problems
8 associated with solar on its system?

9 **A** [LYNCH] I don't think we're having trouble – I don't
10 dispatch, so it's out of my – I don't think with 200 meg
11 – because you have 200 megawatts or 300 megawatts with
12 the net energy metering. I'm not sure that's enough
13 that we can't – that, you know – I don't think that's a
14 big enough dip in the load that we can follow it.

15 **Q** So, to your knowledge, the company's never experienced
16 low-load problems associated with solar?

17 **A** [LYNCH] Not so far. Everybody's complaining about it
18 and worried about it, though. There's been a lot of
19 meetings, because we don't know where this is going.

20 **Q** And has the company ever experienced ramping-rate
21 problems associated with solar on its system, to your
22 knowledge?

23 **A** [LYNCH] Well, I don't dispatch the system, so I don't –
24 yeah, I'm thinking we can follow the load right now. I
25 haven't heard anybody say we can't follow the load.

1 Q Have you, in coming up with these reports and
2 calculations, have you or anyone who worked for you ever
3 made any projections about when these operational issues
4 are going to have a material impact on the company's
5 system?

6 A [LYNCH] Well, I'm thinking the study demonstrates that
7 there is a material impact in the avoided-cost
8 calculations. I mean, that's what PROSYM is telling me.

9 Q But it's not clear when these problems start to kick in?

10 A [LYNCH] People have looked at it, and I'm not sure we
11 have a final determination. But I know our – the
12 economic resource commitment fellow, who dispat- – he
13 looks at what the load is, makes projections of load and
14 how we can meet the system and that sort of thing.
15 We've asked him to do some calculations, and it seems
16 that when you get to 800 megawatts on the system you
17 start having problems, particularly you have significant
18 problems as you can't follow the load if you lose some
19 units. We depend on Fairfield Pumped Storage, for
20 example, since you can – you can pump – you know, you
21 can add load, so that pumping helps.

22 Q So you think 800 megawatts is about the point at which –
23 are you confident that 800 megawatts on the system is
24 the point at which these operational issues kick in?

25 A [LYNCH] Oh, I can't say – I wouldn't say "confident,"

1 but 800 is a number that they've been looking at.

2 Q All right. You mentioned variable integration costs.
3 Can you explain what those are?

4 A [LYNCH] Yeah, they're the terminology that we're using.
5 It means problems with serving the load, so you have to
6 follow the load and maintain frequency of all these
7 assets, so it's that sort of thing. It's an operational
8 type issue.

9 Q Okay. And the company is studying these integration
10 costs; is that right?

11 A [LYNCH] Yeah, there's the – yes, we're all worried about
12 it. Yes.

13 Q And I believe you said in your summary and maybe just a
14 few minutes ago that these variable integration costs
15 are part of the avoided-cost calculation that you
16 presented here today. Is that right?

17 A [LYNCH] They would be embedded in the cost. So how much
18 you save with a solar profile will be affected by how
19 hard it is to follow the load with that solar profile.

20 Q Dr. Lynch, do you know – if you can say – whether, under
21 the company's purchased power agreements with qualifying
22 facilities, the company requires qualifying facilities
23 to pay any variable integration costs that might be
24 assessed by the company?

25 A [LYNCH] I think there's terminology like that in the

1 contracts. I think. Maybe even the interconnection
2 cost. That's not my area.

3 **Q** Okay. Would it be appropriate to both assess those
4 costs separately in a power purchase agreement and also
5 use them to reduce the avoided-cost rates? Or wouldn't
6 that be double-counting of integration costs?

7 **A** [LYNCH] Well, I mean, I suppose you'd have to work it
8 out, but, of course, there's 875 megawatts of solar;
9 their contract price is set. I mean, they're getting
10 capacity payments, too.

11 **Q** Okay.

12 **A** [LYNCH] So, going forward, you know, we'd have to figure
13 that out.

14 **Q** So you don't know if it's the company's intention to no
15 longer require qualifying facilities to separately pay
16 integration costs in their power purchase agreements?

17 **A** [LYNCH] I don't know how they're going to even measure
18 that. I don't know how that's going to work. I think
19 they see the problem and they want language in the
20 contracts to address the problem when it shows up, and
21 when they see it they'll know what it is and measure it,
22 and we'll have to go from there.

23 **Q** So your understanding, going forward, is that the
24 company's intention, with regard to variable integration
25 costs, is just to kind of bake them into the avoided-

1 cost rates? Is that right?

2 A [LYNCH] Intention. My job is to calculate the avoided
3 costs from a solar profile. And so when we dispatch the
4 system without it, dispatch it with it, calculate, and
5 there's the change in production cost.

6 Q Yeah, if you don't know –

7 A [LYNCH] How those contracts and things work out, I don't
8 know.

9 Q I understand. So Dr. Lynch, the current PR-2 tariff
10 pays different rates sort of per kilowatt-hour to QFs
11 based on when those kilowatt-hours are produced; is that
12 right?

13 A [LYNCH] The PR-2, we figure with solar profile now, so
14 it would be just one rate, since it's a solar profile.

15 Q I'm sorry, I mean the current, on-the-books PR-2 rate
16 pays –

17 A [LYNCH] Yes, you have the four time periods. Yes.

18 Q And why are there four different time periods? Why do
19 QFs get paid different rates at different times of day
20 and year?

21 A [LYNCH] Well, last year, the hope was to have one rate
22 and calculate avoided cost by time period, and then
23 whatever energy a QF put into that time period, we'd pay
24 them that rate. That was sort of the idea behind it.
25 But part of the study I did shows that that won't work

1 now because of all the solar on the system.

2 **Q** But the theory behind paying different on-peak and off-
3 peak rates is that energy is more or less valuable at
4 different times of day; is that right?

5 **A** [LYNCH] Yeah, different periods of the day. Yeah.

6 **Q** But as you said, the proposed tariff, the proposed PR-2
7 rate, just pays a single price for every kilowatt-hour,
8 no matter when it's produced?

9 **A** [LYNCH] Yeah, because it's designed for a solar profile,
10 which is going to produce whenever the sun is up, so it
11 has a similar – all of them have a similar profile.

12 **Q** So would you agree that the proposed new approach would
13 eliminate any economic benefit to producing power during
14 peak hours as opposed to during non-peak hours?

15 **A** [LYNCH] No. No. Well, in the number it's a – the
16 calculation of that number includes the prof- – it's
17 based on the profile of solar facility, so it has
18 embedded in it the avoided cost during peak periods,
19 off-peak periods, and it's based on the profile that
20 went in there. So it's going to have the weight – the
21 weighting is based on the solar profile.

22 So, let me say it again. So instead of having four
23 time periods where whatever bucket it comes in, the
24 buckets are sort of internal to the calculation since
25 we're using the solar profile.

1 Q But every kilowatt-hour that gets put on the grid earns
2 the same rate no matter when; is that right?

3 A [LYNCH] Yes. Yeah, we just –

4 Q Is that an industry-standard approach?

5 A [LYNCH] I don't know.

6 Q Do you know of other utilities that follow that
7 approach?

8 A [LYNCH] How they design their rates and stuff? I don't
9 really know.

10 Q Dr. Lynch, I'd like you to please look at – this is
11 another part of Exhibit 5. This is JML-4, your Exhibit
12 JML-4, on calculating the capacity benefits of solar
13 QFs.

14 A [LYNCH] [Indicating.] Yes, sir.

15 Q So, Dr. Lynch, this is another study that was prepared
16 under your supervision; is that right?

17 A [LYNCH] That's correct.

18 Q And you testify – in your direct testimony, you testify
19 that, at present, solar provides zero capacity on the
20 company's system – well, no, solar does not avoid –

21 A [LYNCH] Incremental solar beyond 865 megawatts does not
22 provide – does not avoid capacity in the resource plan.

23 Q Okay. And that's because a resource has to provide
24 capacity in the winter, as well as the summer, in order
25 to avoid the need for capacity and thereby have capacity

1 value; is that right?

2 **A** [LYNCH] Yeah. In my testimony, I sort of demonstrate
3 with a 21 percent reserve margin in winter that our
4 capacity need in winter is greater than the capacity
5 need in the summer. And I also do it for 18, when it's
6 18 percent, the capacity need in winter is greater than
7 summer. And I know Mr. Horii did a calculation in his
8 surrebuttal, saying I was wrong about that, but that's
9 because his calculation had that 100 megawatts of demand
10 response, which is a program we don't have in place yet,
11 and it's sort of being designed to meet the winter need
12 of capacity, so you really can't use it to measure or
13 quantify or determine what that peak need is.

14 **Q** Dr. Lynch, while we're talking about demand response, if
15 you don't mind, actually, a quick look back at JML-1, at
16 your table here? Sorry to jump around a little bit.
17 JML-1 is the spreadsheet.

18 **A** [LYNCH] Yes. Yeah, that's there.

19 **Q** And you mentioned demand response when we were talking
20 about this. And you testified that, in 2020, the winter
21 peak-clipping program kind of kicks in and provides an
22 additional —

23 **A** [LYNCH] Hundred megawatts.

24 **Q** Yeah, although here it looks like it goes from 276 to —
25 I'm sorry, no. A hundred megawatts, you're right. And

1 then in subsequent years it sort of stays at around 100
2 megawatts; is that right?

3 **A** [LYNCH] For the new program, all we did was put 100
4 megawatts in.

5 **Q** Okay. You do project that winter peaks will grow over
6 times, over the course of the time period here; is that
7 right?

8 **A** [LYNCH] Yes.

9 **Q** Okay. So you're not proposing or not projecting to
10 adjust the size of that demand-response program to track
11 growth and demand?

12 **A** [LYNCH] I was kind of thinking of it as a placeholder.
13 I think the company's agreed to look into it to see what
14 can be done. So, hopefully, it would be more than 100 –
15 that's my hope, is that it would be more than 100
16 megawatts.

17 **Q** Okay.

18 **A** [LYNCH] But this is – like, this is a plan and we're not
19 sure.

20 **Q** Okay. But this plan assumes that there's no growth in
21 the [word indiscernible] after the first year.

22 **A** [LYNCH] Well, I – no, if it's 100 megawatts, yes, that's
23 correct.

24 **Q** To follow up what you were saying about winter peaks and
25 capacity on the system, you testified that because the

1 company has to procure capacity to deal with winter
2 peaks plus its reserve margins, solar can't avoid that
3 capacity cost because it doesn't produce during those
4 peak times?

5 A [LYNCH] That's right. So if you have to provide
6 capacity in the winter, if that's when you need it, you
7 also need it in the summer, as well. And the solar may
8 help in the summer; it'd be a help. But if you have to
9 build the capacity in the winter, anyway, then there's
10 nothing to be avoided.

11 Q So if a QF project could provide output during those
12 winter peaks, then you would have capacity value?

13 A [LYNCH] Oh, yeah, potentially. So, the thing is, if
14 solar came with battery, well, the battery could
15 represent capacity value on it. So it would be a
16 different valuation. My thinking is that we'd negotiate
17 with those guys if they show up, the first couple or
18 two, three farms. Plus, we're going to do an RFP to
19 sort of get a handle on what a solar-and-battery
20 valuation or how the operation would work.

21 Q Okay. Dr. Lynch, do you know of any other utilities
22 that assign zero avoided – zero capacity value to solar
23 resources?

24 A [LYNCH] I wouldn't – I don't know.

25 Q All right. Dr. Lynch, I'd like to talk for a few

1 minutes about your conclusions about reserve margins,
2 about winter reserve margins. Can you explain the
3 relationship between winter peaks and reserve margin?

4 A [LYNCH] I'm sorry?

5 Q Can you explain the relationship between winter peaks
6 and the reserve margin? Or can you explain what the
7 reserve margin is?

8 A [LYNCH] Oh, so the reserve margin represents the amount
9 of additional capacity need to reliably serve the load,
10 and it's typically expressed as a percentage of peak.
11 So winter reserve margin would be a percentage of the
12 winter peak.

13 Q So it's sort of a margin of safety?

14 A [LYNCH] Yes.

15 Q So you make sure that the company –

16 A [LYNCH] Something like that, yes.

17 Q Okay. So the company's – the capacity needs that are in
18 the plan represent the actual projected peaks plus that
19 reserve margin on top; is that right?

20 A [LYNCH] The resources in the plan would represent that,
21 yes.

22 Q And the company's decided that the margin of safety has
23 to be higher in winter than in summer; is that right?

24 A [LYNCH] That's correct.

25 Q Okay. And so you testified that SCE&G needs a minimum

1 of 21 percent of its projected winter peak demand as a
2 reserve margin and 14 percent during the rest of the
3 year; is that right?

4 A [LYNCH] Right.

5 Q So the winter reserve margin is about one and a half
6 times the size of the margin for the rest of the year;
7 is that right?

8 A [LYNCH] Yes. Yeah.

9 Q Okay. How does this 21 percent winter reserve margin
10 compare with the reserve margins of other utilities in
11 the region?

12 A [LYNCH] Well, PJM has 27 percent in the winter and 16-
13 point-something in the summer. Duke, I think, is 17
14 percent. Southern is 17 percent, but Southern may be
15 summer peaking, I'm not sure.

16 Q Dr. Lynch, you just mentioned this 27 percent reserve
17 margin for –

18 A [LYNCH] PJM, yeah.

19 Q – PJM. So you maintain that's their winter reserve
20 margin?

21 A [LYNCH] Oh, yes. Yeah.

22 Q Okay. Have you reviewed Dr. Horii's surrebuttal
23 testimony?

24 A [LYNCH] Yes.

25 Q Okay.

1 **A** [LYNCH] So he explains that the winter reserve margin at
2 PJM is different than the summer reserve margin, that
3 it's a winter weekly reserve target – WWRT, something
4 like that – and that they don't use a winter reserve
5 margin to add capacity, but the difference, the reason
6 they don't do that, is because their summer reserve
7 margin is binding. If you look at their forecast and
8 their loads, their summer peak typically is 15 to 16
9 percent higher than their winter peak, normal weather.
10 So in the summer, if you add another 16 percent reserve
11 margin to meet the summer demand, that will
12 automatically give you something like a 32 percent,
13 mid-30 percent reserve margin, on the winter. So PJM
14 wasn't worried about the winter.

15 **Q** Okay.

16 **A** [LYNCH] Until – then we get into this polar vortex –
17 until the polar vortex came in 2014. And at that point,
18 they realized that that spread, that 15-16 percent
19 spread between summer and winter disappears very
20 quickly.

21 **Q** So it's your view that that winter weekly reserve target
22 that PJM has, that that's really exactly the same –
23 represents exactly the same thing as the company's
24 winter reserve margin?

25 **A** [LYNCH] Yeah, not only that – I like talking about PJM

1 because they're sort of in the same boat as we are, is
2 that they hit that polar vortex and then they started
3 finding out when the spread between summer and winter
4 peaks closed, because of weather, they realized that
5 their loss of load expectation methodology, they
6 thought, "Well this isn't really working. It's not an
7 adequate way to measure risk on the system because of
8 the winter risks," and –

9 **Q** So –

10 **A** [LYNCH] – they started these studies.

11 **MR. MUSTIAN:** Mr. Chairman, If Mr. Snowden
12 would allow Dr. Lynch to finish his answer, I would
13 appreciate it.

14 **BY MR. SNOWDEN:**

15 **Q** Go ahead.

16 **CHAIRMAN WHITFIELD:** Yes, Mr. Snowden, let him
17 finish.

18 **BY MR. SNOWDEN:**

19 **Q** Sorry about that.

20 **A** [LYNCH] Yeah, just because this is a good point. So
21 they have their RAAS Committee – Reliability, Accuracy,
22 Assessment Subcommittee – and they've been studying
23 reserves on – the winter reserves on the PJM system, and
24 it's been three or four years now they put out reports.
25 Mr. Horii said they haven't come to a conclusion yet. I

1 haven't found their report. But they're analyzing this
2 winter risk they're facing; it's significant, and
3 they're trying to do something about it. And the
4 estimate is a 27 percent reserve margin, is what they're
5 calculating. And it's sort of the same problem SCE&G
6 has, we see this risk in the winter on our system, only
7 we don't have the cushion – this 16 percent spread
8 between summer and winter – so, for us, the winter is
9 even a bigger problem.

10 Q So you don't agree with Dr. Horii's statement that PJM
11 does not have a higher reserve margin in the winter?

12 A [LYNCH] PJM says they have a 27 percent – he's saying
13 they don't have a 27 percent reserve margin?

14 Q Yeah, he says that PJM doesn't have a higher winter
15 reserve margin in the winter.

16 A [LYNCH] Oh, then he's wrong. I don't know about higher;
17 it's 27 percent, and in the summer it's 16 percent. So,
18 yeah, so it's higher, yeah.

19 Q So you think this winter weekly reserve target and that
20 the 27 percent PJM to 21 percent SCE&G, that's an
21 apples-to-apples comparison in your view?

22 A [LYNCH] Oh, yeah, absolutely.

23 Q Okay.

24 A [LYNCH] The only difference, like I say, is that their
25 27 percent isn't binding on their system, or they don't

1 think it is. The 16 percent is. They have 16 percent
2 in summer, that means they have 30-some-odd percent in
3 the winter, which will be higher than the 27 percent –
4 if you see what I mean. So the summer reserve is
5 binding on their system. On our system, the winter is
6 binding, because we don't have the spread that they
7 have, that 16 percent spread between normal summer weeks
8 and normal winter peaks – our winter and summer peaks
9 are very similar now, very close.

10 **Q** Dr. Lynch, in your direct testimony, you discuss the
11 company's current reserve margin policy; is that right?

12 **A** [LYNCH] Yes.

13 **Q** Okay. And so this current reserve margin policy, that's
14 reflected in the resource plan that's this JML-1, the
15 table?

16 **A** [LYNCH] That's correct.

17 **Q** Okay. And you also testified that this is just a plan
18 and it's not a decision; is that right?

19 **A** [LYNCH] That's correct.

20 **Q** Okay. So that means the company is not bound to that 21
21 percent reserve margin; is that right?

22 **A** [LYNCH] Well, I mean, I've got approval for it. I mean,
23 I go around the company showing them this and explaining
24 it. But they can change – the management can change
25 their minds.

1 Q If you're explaining it to lawyers, we probably get – we
2 confuse pretty easily.

3 Q [LYNCH] Well, I mean, they agreed that 20 percent was
4 reasonable, to everybody I spoke to. But they can
5 certainly change their mind.

6 Q But you do testify that the resource plan is only a plan
7 and not a decision, and that the company reserves the
8 right to change that resource plan as may be warranted,
9 right?

10 A [LYNCH] Yes, that's correct.

11 Q What was the company's reserve margin policy last year?

12 A [LYNCH] For a number of years, we had a 14 percent
13 summer reserve margin.

14 Q Okay. Has the company ever had a winter reserve margin,
15 before?

16 A [LYNCH] No.

17 Q Okay. But you conclude that, going forward, the company
18 should maintain a 21 percent winter reserve margin.

19 A [LYNCH] Yes.

20 Q And was there any new information since last year that
21 prompted this change in the reserve margin policy?

22 A [LYNCH] Well, we got around to analyzing it. I mean,
23 even last year, when we talked about the avoided costs,
24 if you recall, we put some of the avoided capacity costs
25 in the winter and argued that we have that winter risk,

1 even though we hadn't analyzed it yet. But sort of
2 what's happening on the system is we're getting a lot of
3 solar behind the meter, so every time you get a solar
4 farm behind somebody's meter, it's going to lower the
5 resulting demands on the system in the summer, but won't
6 affect in the winter. Another thing going on – see,
7 now, we've done the analysis, because the risk is there
8 and we've known about the risk, I think, since the polar
9 vortex, where we can see that this jumps up. But a
10 Residential class typically peaks in the winter, normal
11 weather. So the more residential customers you have on
12 the system, the more – the greater the increase will be
13 in the winter demand than the summer demand. So all of
14 these factors kind of pull this stuff – you know, close
15 the gap between winter and summer.

16 **Q** So if I can ask, when did you begin to analyze this
17 issue?

18 **A** [LYNCH] I know all last year I had a goal of getting a
19 resource – updating the reserve margin, so it was all
20 last year. But we've been talking about it for a number
21 of years, because even I think over the last – well,
22 over the last five years, we peaked in the winter three
23 out of five years. And if you go back ten years, I
24 think it's five out of ten, or something. I know we've
25 reported that someplace. So we've been looking, we've

1 known about that something is going on and that we'd
2 have to deal with it.

3 Q Dr. Lynch, is it safe to say that this change in
4 reserve-margin policy is largely responsible for the
5 zero capacity value that's assigned to solar?

6 A [LYNCH] Well, yes. Yes.

7 Q So, you mentioned in previous years that the company
8 assigned an 80 percent capacity value to its summer and
9 20 percent in winter; is that right?

10 A [LYNCH] Yes. Yeah, I remember arguing with Dr. Vitolo
11 about that.

12 Q So, under the current rate schedule – so, under the
13 current rate schedule, payment for – capacity payment
14 for critical peak hours in the summer is, what, about
15 three times the payment, the capacity payment, for
16 winter peak times?

17 A [LYNCH] Yeah, we did away with the critical peak hours.
18 And part of the realization is when you have all the
19 solar on the system, it's shifting the time of the peak,
20 so it doesn't make sense really to pick out hours ahead
21 of time.

22 Q But just referring to the current sort of on-the-books
23 rate, the –

24 A [LYNCH] Oh, that was designed last year. Yeah, so
25 capacity was split 80/20 – 80 percent in the summer, 20

1 percent in winter. Is that your question?

2 Q That's right.

3 A [LYNCH] Yeah.

4 Q And so under the current rate schedule, the compensation
5 that is received by a solar QF already accounts for the
6 fact that the QF may not be delivering capacity during
7 winter peak hours; is that right?

8 A [LYNCH] Yeah that's correct.

9 Q So if they're not producing during those winter peak
10 hours, they don't get paid for it?

11 A [LYNCH] That's right, yes.

12 Q And the company is proposing to do away with this 80/20
13 split now; is that right?

14 A [LYNCH] Yes.

15 Q Okay. Dr. Lynch, in preparing for – since the PR-2
16 rates were last updated, did you ever calculate what
17 avoided capacity rates would be for solar in the absence
18 of this reserve margin policy?

19 A [LYNCH] No.

20 Q Never ran that calculation?

21 A [LYNCH] Even the question doesn't make sense. If you
22 need a reserve margin policy, you have to have an
23 expansion plan.

24 Q When did you – when was the reserve margin policy
25 stamped, as it were?

1 A [LYNCH] I could point to a specific date, but I don't
2 know what it is. Maybe November or December, something
3 along those lines.

4 Q Did you ever seek to quantify sort of what the impact on
5 avoided-cost rates would be?

6 A [LYNCH] No, no I didn't. Reserve margin was being
7 figured out. Had nothing to do with avoided cost.

8 Q We talked a few minutes ago – a little while ago about
9 solar and storage facilities and about some of the
10 economic benefits of pairing storage with generation; is
11 that right?

12 A [LYNCH] Yes.

13 Q And so the pairing of solar and storage could have
14 benefits to ratepayers; is that right?

15 A [LYNCH] Well, I suppose if you pay the solar-plus-
16 battery the avoided cost, ratepayers don't get a
17 benefit. It's a wash, right? They're held –

18 Q They're held in different –

19 A [LYNCH] They're held in a different kind of way?

20 Q Yeah, if they –

21 A [LYNCH] Oh, I shouldn't ask you a question. I think
22 there's no change to their benefit from that, if they're
23 paid the right avoided cost.

24 Q Well, let me ask it another way. Do you think it would
25 be a good thing if storage resources were more widely

1 deployed in South Carolina – assuming that made economic
2 sense?

3 **A** [LYNCH] Well, yeah, I think – now, all the studies I've
4 read – maybe I can't say all the studies. I've read a
5 few of them. It always seems to me, my impression is
6 that the battery has value more for ancillary services
7 right now, and that for moving energy around, which
8 you'd want to, you know, take it off-peak, on-peak, that
9 sort of thing, that's not just quite economic, but
10 close.

11 **Q** You are aware that in some states there are sort of
12 battery solar – solar-plus-storage facilities in
13 operation right now?

14 **A** [LYNCH] Oh, yeah. Yeah, yeah, particularly California.
15 That was one of the studies that I got my hands on.

16 **Q** Okay. Now, would you agree that the proposed rates
17 wouldn't confer any economic benefit to a solar QF for
18 adding storage to its project?

19 **A** [LYNCH] Oh, yeah, yeah. I would think a solar-plus-
20 battery is a different kind of animal than just a plain
21 solar, and I would advise the company to negotiate with
22 that kind of a facility. And if a lot of them show up,
23 then maybe you have to redesign the rates, maybe put a
24 capacity payment, something of that sort.

25 **Q** So the proposed rate doesn't provide any economic

1 incentive to add storage?

2 A [LYNCH] I don't think so.

3 Q We're almost to the end. Thank you for your time. Dr.
4 Lynch, you've testified in a few places in your direct
5 and rebuttal testimony that the company's not proposing
6 any significant changes to its methodology for
7 calculating avoided-cost rates; is that right?

8 A [LYNCH] It's my contention we're using the same
9 methodology, difference in revenue requirements.

10 Q Okay. So there aren't significant changes to the way
11 the company is implementing the DRR methodology?

12 A [LYNCH] The only – the only way I know how to calculate
13 avoided cost, the only way that makes sense to me, is
14 the difference in revenue requirements: base case,
15 change case, what's the difference. So that's the
16 philosophy. But now we do have 875 megawatts of solar
17 now in PPAs on the system; that makes a difference.

18 Q So, we talked a little while ago about the Commission's
19 orders approving the use of this methodology. They're a
20 little more detailed than saying the DRR methodology is
21 okay, aren't they? I mean, do they –

22 A [LYNCH] Well, I'm not a lawyer. I don't know.

23 Q But they do approve specific – very specific details of
24 how the company is to apply the DRR methodology, do they
25 not?

1 **A** [LYNCH] I'm thinking – I probably shouldn't speak for
2 the Commission, but I suspect that they approved the
3 rate, and the methodology they don't object to.
4 Something of that sort. I don't know; that's somebody
5 else. But being approved and mandated and that sort of
6 thing, other than the rate I'm not sure.

7 **Q** I guess I'll ask it this way. If the company was
8 proposing an aspect of its calculation here that was
9 different than what was previously approved by the
10 Commission, would you consider that a significant
11 change?

12 **A** [LYNCH] I guess if we made a significant change, then
13 that would be a significant change. That's what it
14 sounds like the question is. But if we went to the
15 peaker method, for example, instead of difference in
16 revenue requirements, I would feel obligated to make an
17 argument that the peaker method somehow approximated the
18 difference in revenue requirements and for other reasons
19 this may have been appropriate, that sort of thing. But
20 I come back – I don't know how you get away from
21 difference in revenue requirements in terms of
22 methodology.

23 **Q** Okay. So when you say the company isn't making
24 significant changes to its methodology, all you mean is
25 that the company used DRR last year; it's using DRR this

1 year.

2 A [LYNCH] That's what I mean, yes. And I see that as the
3 methodology.

4 Q Okay, Dr. Lynch, I do not have any further questions for
5 you. Thank you very much.

6 A Thank you.

7 CHAIRMAN WHITFIELD: Thank you, Mr. Snowden.
8 Mr. Elliott.

9 MR. ELLIOTT: Yes, sir. Just a few.

10 CROSS EXAMINATION

11 BY MR. ELLIOTT:

12 Q Nothing for you, Dr. Lynch.

13 A [LYNCH] Oh. Glad to see you, Mr. Elliott.

14 [Laughter]

15 Q Yes, sir, pleasure's mine.

16 But I do have just a few for you, Mr. Rooks,
17 please.

18 A [ROOKS] Okay.

19 Q In – could you get Exhibit 1 to your testimony out,
20 please?

21 A [ROOKS] [Indicating.]

22 Q I'll draw your attention to page 1-of-2.

23 A [ROOKS] Okay.

24 Q And, in particular, I want to draw your attention, if I
25 may, what, under your exhibit as filed, is January '18

1 forecasted costs. Do you see that column?

2 A [R00KS] I do.

3 Q And in that column, you are showing a forecast cost of
4 purchased power and interchange received of about \$45
5 million? Am I reading that correctly?

6 A [R00KS] Yes.

7 Q All right. I have not seen, I think, your January fuel
8 report, but have y'all issued that?

9 A [R00KS] Yes.

10 Q So do you know what your purchased power and interchange
11 figure was for January?

12 A [R00KS] The actual – if you'll bear with me one moment,
13 I think I have that.

14 Q Okay.

15 A [R00KS] Yes. Our actual purchased power for January was
16 about \$46.4 million.

17 Q All right. And then, just generally speaking – it is
18 January – is the month and the temperature, is that the
19 driver of that high cost?

20 A [R00KS] Yes, it sure is. I was doing some research
21 today and looking at National Weather Service weather
22 readings. The highest temperature in Columbia or
23 Charleston for the first seven days of the year was 42
24 degrees. Heating degree days were 97 percent above
25 normal, for that heating day period. So it was an

1 extreme weather event. We hadn't seen eight days of
2 heating degree days of that magnitude since going back
3 to '91, from some of the records I saw.

4 Q Yeah. And I'm intrigued that you're able to forecast
5 it?

6 A [R00KS] No, sir. We used, in this case – we did not
7 have complete forecast information available, as of the
8 time of the filing of this testimony, and so we used
9 some numbers that were available to us at that time,
10 that weren't complete, that weren't to the point of
11 final scrutiny.

12 Q But you're real close, is my point.

13 A [R00KS] Yes.

14 Q I'm complimenting you. I wanted to ask, your table is
15 very similar to that of Ms. Smith's, but she has a
16 slight difference in the way she lays out her costs.
17 Are you familiar with her table?

18 A [R00KS] I have reviewed it briefly, not in great detail.
19 But I'd be happy to.

20 Q Well, do you have it handy?

21 A [R00KS] Sure [indicating].

22 Q I just have one short series of questions about it. And
23 I'm looking at Ms. Smith's Exhibit -5, and I'm on page
24 2-of-2, and I'm staying in the same context of that
25 January '18, just for my sake of ease.

1 A [ROOKS] Okay.

2 Q Ms. Smith sets out the public service authority credits.
3 Do you see that fourth line from the top?

4 A [ROOKS] I do.

5 Q All right. Tell me what those credits are.

6 A [ROOKS] That's actually for their portion of site usage,
7 at the site.

8 Q At the nuclear site?

9 A [ROOKS] Correct.

10 Q Yes. And you combine that credit in your fossil-fuel
11 total?

12 A [ROOKS] Correct.

13 Q I'm just curious why?

14 A [ROOKS] Because we credit that to the fossil line,
15 essentially. That's site power for any electrical
16 requirements there; it's split based on the ownership
17 percentages for that project. And so we assess – or, we
18 give customers credit back, because some of that power
19 flowed through, so we give the customers credit back for
20 that amount that Santee reimburses us for.

21 Q All right. And do you have any dispute or issue with
22 Ms. Smith's valuations of those public service authority
23 credits?

24 A [ROOKS] No, I do not.

25 Q Now, in the good old days – say, last year – when we had

1 settlement agreements in these fuel cases, the company
2 always agreed to provide to ORS and the parties to the
3 docket the monthly fuel recovery reports. Do you recall
4 that?

5 A [R00KS] Yes.

6 Q Is the company prepared to continue that practice of
7 providing the ORS and the parties to this docket the
8 monthly fuel recovery reports?

9 A [R00KS] Sure. Yeah, I don't see why we wouldn't.

10 Q All right. Thank you. And then, at the same time, in
11 those previous documents, the company always agreed to
12 provide the ORS and the parties quarterly forecasts,
13 fuel forecasts. Do you recall that?

14 A [R00KS] I do.

15 Q Is the company prepared to continue that practice of
16 providing the ORS and the parties quarterly fuel
17 forecasts?

18 A [R00KS] Yes.

19 Q Good. Thank you for that. And, last, I just want to
20 draw your attention to these, you call them, interest
21 credit swaps? Am I calling them by the right name?

22 A [R00KS] Yeah, that's fair enough.

23 Q I'm close? I might have them in the wrong order. Do
24 you recall writing a letter to the Commission – I
25 believe it was yours – no, do you recall SCE&G writing a

1 letter, Mr. Gissendanner, a letter to the Commission
2 back on February 22, 2018, explaining how y'all intended
3 to proceed with those credit swaps?

4 A [ROOKS] I do.

5 Q Okay. And I think, as I understand it from Mr.
6 Gissendanner's letter, y'all applied about \$115 million
7 in these swaps to fuel?

8 A [ROOKS] Correct. It was about \$113.7 million.

9 Q And so, thus, we can see – coming back to your Exhibit
10 -1 – we can see where, very quickly, you anticipated
11 going, in January, from about a \$55 million
12 undercollection to about a \$52 million overcollection,
13 correct?

14 A [ROOKS] Correct.

15 Q That accounts for that. Now, apparently, you did even
16 better than the \$115 million in swaps. I think you got
17 another \$39 million, roughly, about the same time?

18 A [ROOKS] Not –

19 Q Did you settle –

20 A [ROOKS] Not sure on that. Just – was that in the
21 letter?

22 Q It is. And if you don't know, that's fine, but let me
23 try a little farther. Mr. Gissendanner writes that, in
24 December of '17, E&G settled eight interest-rate swaps
25 at an aggregate cost of \$39 million. Does that sound

1 familiar to you?

2 **A** [ROOKS] Yes. That would be positions that were not at a
3 gain, but at a loss.

4 **Q** All right. And so what I – in Mr. Gissendanner's
5 letter, and this is my point, he goes on to say that it
6 would be treated, I think, as a regulatory asset, as set
7 out in the joint Petition filed on January 12, 2018, and
8 he refers the reader to paragraph 57(C)(1) of the joint
9 Petition? Do you know exactly how the joint Petition
10 proposed to do that, in this paragraph 57(C)(1)?

11 **A** [ROOKS] I don't have that right in front of me, but my
12 understanding is that those are supposed to be amortized
13 over the life of the debt issuance that they were tied
14 to.

15 **Q** Okay.

16 **A** [ROOKS] So, over time, that can gradually be amortized
17 away.

18 **MR. ELLIOTT:** Very fine. All right, good.

19 That's all I have. Thank you.

20 Thank you, Mr. Chairman.

21 **CHAIRMAN WHITFIELD:** Thank you, Mr. Elliott.

22 Ms. Ottenweller, questions for this panel?

23 **MS. OTTENWELLER:** I do have some questions.

24 Should I proceed at this time? I would say I have
25 maybe 30 minutes, or so.

1 **CHAIRMAN WHITFIELD:** Tell you what, let's take
2 a brief break and we'll come back and let you
3 proceed. We're going to – once we take a five-
4 minute break, we're going to go to about 5:45. So
5 we'll take a brief five-minute recess.

6 [WHEREUPON, a recess was taken from 4:56
7 to 5:05 p.m., during which time the
8 witnesses stood aside.]

9 **CHAIRMAN WHITFIELD:** Please be seated. I'll
10 call this hearing back to order. I understand the
11 company witnesses have stood aside just briefly
12 and, at this time, Ms. Ottenweller, we're going to
13 accommodate you to present your witness.

14 **MS. OTTENWELLER:** Thank you, Mr. Chairman. I
15 appreciate it. South Carolina Coastal Conservation
16 League and Southern Alliance for Clean Energy would
17 like –

18 **CHAIRMAN WHITFIELD:** Could you get to a
19 microphone for us?

20 **MS. OTTENWELLER:** Sure [indicating]. CCL and
21 SACE would like to call Devi Glick to the stand. I
22 think we're going to put her up here, so that the
23 witnesses can leave their stuff, if they wanted to.

24 **CHAIRMAN WHITFIELD:** Okay, come forward.

25 [Witness affirmed]

1 THEREUPON came,

2 D E V I C . G L I C K ,

3 called as a witness on behalf of Intervenor South Carolina
4 Coastal Conservation League and Southern Alliance for Clean
5 Energy, who, having been first duly affirmed, was examined
6 and testified as follows:

7 DIRECT EXAMINATION

8 BY MS. OTTENWELLER:

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

11 A Devi Charlotte Glick. Synapse Energy Economics, 485
12 Massachusetts Ave., Cambridge.

13 CHAIRMAN WHITFIELD: I don't think your
14 microphone is on – it is now? Okay.

15 BY MS. OTTENWELLER:

16 Q Ms. Glick, did you cause to be prefled in this docket a
17 public version of direct testimony consisting of 32
18 pages and two exhibits?

19 A Yes.

20 Q Did you also cause to be prefled in this docket a
21 confidential version of direct testimony consisting 32
22 pages and the same two exhibits as the public version of
23 your testimony?

24 A Yes.

25 Q Did you also cause to be prefled in this docket

1 surrebuttal testimony consisting 16 pages and two
2 exhibits?

3 **A** Yes.

4 **Q** Do you have any changes or corrections to your prefiled
5 direct or surrebuttal testimony?

6 **A** Yes, I do have a few corrections.

7 **Q** Please tell us what those are.

8 **A** On page 22 of my direct testimony, line six, it should
9 say Section 5, not Section 3. Additionally, on page 32
10 of my direct testimony, line 15 should say Table 9, not
11 Table 6.

12 **Q** Other than those corrections, if the questions put to
13 you in your testimony were asked at the hearing today,
14 would your answers be the same?

15 **A** Yes, they would.

16 **Q** And were the exhibits prepared by you or under your
17 direction?

18 **A** Yes.

19 **MS. OTTENWELLER:** Mr. Chairman, the other
20 parties have stipulated to Ms. Glick's testimony
21 and I would ask that it be admitted into the record
22 at this time. I want to make a couple of notes:
23 One is that we've agreed that the confidential
24 version would no longer be deemed confidential, so
25 I would ask that the confidential version be

1 stipulated into the record with that confidential
2 portion on page 15 unredacted.

3 CHAIRMAN WHITFIELD: We'll enter her direct
4 testimony unredacted and the surrebuttal portion of
5 her testimony will be – you wanted that one page
6 confidential? Is that what you're saying?

7 MS. OTTENWELLER: The confidential portion was
8 actually in the direct testimony, but that's now no
9 longer confidential.

10 CHAIRMAN WHITFIELD: Okay, right. Unredacted.
11 Okay.

12 MS. OTTENWELLER: Great.

13 CHAIRMAN WHITFIELD: We'll enter the
14 surrebuttal portion of her testimony, as well.

15 MS. OTTENWELLER: Thank you, Mr. Chairman.

16 CHAIRMAN WHITFIELD: Sorry, I had a confusing
17 note over here.

18 MS. OTTENWELLER: Yeah, it's a confusing
19 process. I would also ask to have the exhibits
20 attached to her prefiled direct and surrebuttal
21 testimony identified as Exhibits DCG-1 and DCG-2,
22 DCG-3, and DCG-4 moved into the record.

23 CHAIRMAN WHITFIELD: Okay. We're going to
24 make that a composite exhibit. Her DCG-1 and
25 DCG-2, also her surrebuttal Exhibits DCG-3 and

1 DCG-4, and we'll make that a composite exhibit and
2 make that Hearing Exhibit No. 8.

3 [WHEREUPON, Hearing Exhibit No. 8 was
4 marked and received in evidence.]

5 MS. OTTENWELLER: Thank you, Mr. Chairman.
6 And for the sake of time, we're forgoing the
7 summary, since all the parties have stipulated to
8 her testimony.

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23 [THE PREFILED DIRECT TESTIMONY {W/CORRN'S} OF
24 DEVI C. GLICK, IN UNREDACTED FORM, FOLLOWS
25 AT PGS 379-412(E-109 - E-142)]

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

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

**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**

March 23, 2018

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1 **1. INTRODUCTION AND QUALIFICATIONS**

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

3 A. My name is Devi Glick. I work at Synapse Energy Economics, Inc., located at
4 485 Massachusetts Avenue in Cambridge, Massachusetts.

5 **Q. Please describe Synapse Energy Economics.**

6 A. Synapse Energy Economics is a research and consulting firm specializing in
7 electricity and natural gas industry regulation, planning, and analysis. Our work
8 covers a range of issues, including integrated resource planning; economic and
9 technical assessments of energy resources; electricity market modeling and
10 assessment; energy efficiency policies and programs; renewable resource
11 technologies and policies; and climate change strategies. Synapse works for a
12 wide range of clients, including attorneys general, offices of consumer advocates,
13 public utility commissions, environmental advocates, the U.S. Environmental
14 Protection Agency, the U.S. Department of Energy, the U.S. Department of
15 Justice, the Federal Trade Commission, and the National Association of
16 Regulatory Utility Commissioners. Synapse has over 20 professional staff with
17 extensive experience in the electricity industry.

18 **Q. Please summarize your professional and educational experience.**

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

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

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

7 My CV is attached as Exhibit DG-1.

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

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

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

13 A. No.

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

15 A. The primary purpose of my testimony is both to provide input recommendations
16 for improving on South Carolina Electric & Gas Company's ("SCE&G" or "the
17 Company") avoided cost calculations offered to qualifying facilities ("QFs")
18 under the Public Utilities Regulatory Policies Act of 1978 ("PURPA") and to
19 provide input on the 2018 application of the Net Energy Metering ("NEM")
20 Methodology for valuing the costs and benefits of Distributed Energy Resources
21 ("DERs"). Additionally, my testimony addresses SCE&G's proposed PR-1 and
22 PR-2 tariffs.

23 **Q. How is the remainder of your testimony organized?**

24 A. My testimony is organized as follows:

- 25 1. Introduction and Qualifications
- 26 2. Summary of Conclusions and Recommendations
- 27 3. Avoided Generation Capacity Cost Methodology

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

4 **Q. Are you sponsoring any exhibits?**

5 A. Yes. I am sponsoring the following exhibits:

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

8

9 **2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS**

10 **Q. Please summarize your primary conclusions.**

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

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

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

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1 to avoided generation capacity costs. These errors appear to be at odds with
2 PURPA and result in artificially low avoided cost payment rates in tariffs PR-
3 1 and PR-2.

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

10 **Q. Please summarize your primary recommendations.**

11 **A.** I also recommend that the Commission require the Company to correct its
12 methodological and technical errors associated with its QF avoided cost
13 determination (including recalculating the avoided generation capacity cost using
14 the prior approved methodology), so that QFs are compensated appropriately as
15 required under the Public Utility Regulatory Policies Act of 1978 and subsequent
16 requirements. The Company should file revised PR-1 and PR-2 tariffs correcting
17 the errors prior to Commission approval of the new tariffs.

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

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

26 I recommend that the Commission require the Company to calculate its avoided
27 transmission and distribution costs within the NEM methodology framework and
28 update its avoided line loss values. The Company should calculate and add these

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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.

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1 Step 2: "Identif[y] the set of critical peak hours where energy would have a
2 capacity value on the system and spread the avoided capacity cost across those
3 hours."³ Witness Lynch outlined this process in Docket 2016-2-E:

4 SCE&G determined the critical peak hours by analyzing the hours when
5 its load fell within 95% of seasonal peak in the last 15 years (page 17,
6 lines 9-10).

7 There are 380 critical peak hours within 95% of the summer peaks and 88
8 critical peak hours within 95% of the winter peaks. The winter hours are
9 approximately 20% of the total. Accordingly, SCE&G assigns 80% of the
10 annual avoided capacity cost...to the summer and 20% to the winter based
11 on the number of hours occurring in each critical peak season (page 18,
12 lines 2-7).

13 Table 1 outlines the seasonal capacity costs as calculated by SCE&G in Docket
14 2017-2-E.⁴ The summer component was \$5.08 per kW-year and the winter
15 component was \$1.27 per kW year. The summer capacity payment was
16 \$0.01965/kWh based on 264 critical peak hours in the summer season and the
17 winter capacity payment was \$0.00675/kWh based on 192 critical peak hours in
18 the winter season.⁵

19 **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.

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

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

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

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

14 **A.** No, SCE&G did not.

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

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

22 Since SCE&G's Reserve Margin Study shows that SCE&G needs as much
23 capacity in the winter as it does in the summer, a resource has to provide
24 capacity in the winter as well as the summer in order to avoid the need for
25 capacity and thereby have capacity value. Because solar does not provide
26 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.

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

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

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

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

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

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

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

20

21 **4. WINTER RESERVE MARGIN**

22 **Q. What is a winter reserve margin?**

23 A. According to the National Energy Regulatory Commission, "reserve margin is the
24 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.

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

6 **Q. What has SCE&G’s winter reserve margin been historically?**

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

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

9 A. SCE&G has increased its winter reserve margin to 21 percent,^{12,13} a 50 percent
10 increase over the winter reserve margin used last year.

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

12 A. The Company’s proposed winter reserve margin is substantially higher than peers
13 Duke Energy Carolinas, Duke Progress, Southern Company, and Santee Cooper,
14 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.

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

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

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

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

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

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

²⁰ South Carolina 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 Carolina 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.

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- 1 **Q. Please describe the methodologies used by regional peer utilities to calculate**
2 **their reserve margins, and how these methodologies differ from the one used**
3 **by SCE&G.**
- 4 **A. Southern Company, Duke Energy Carolinas, and Duke Energy Progress utilize**
5 **reserve margins that were calculated with extensive analysis focused on balancing**
6 **the physical needs of the system and the economic cost imposed on customers.**
- 7 • Southern Company (Georgia Power, Alabama Power, Gulf Power, Mississippi
8 Power) utilized a system dispatch model named Strategic Energy and Risk
9 Valuation Model (SERVM) to evaluate production costs relative to customer
10 costs of outages. It published a 62-page study detailing what it deems to be an
11 economically optimum 17 percent reserve margin.²³
- 12 • Duke Energy Progress and Duke Energy Carolinas retained Astrape
13 Consulting to conduct a resource adequacy study in both 2012 and 2016.
14 Their 17 percent winter reserve margins also utilize a methodology that makes
15 efforts to balance reliability and cost minimization.^{24,25,26}
- 16 **Q. What are your recommendations regarding SCE&G's winter reserve**
17 **margin?**
- 18 **A. I have two recommendations:**
- 19 1. The Commission should require that SCE&G hire an independent firm to
20 conduct an analysis to determine an appropriate reserve margin for both winter
21 and summer. This study should utilize a methodology that balances physical
22 reliability with minimizing economic costs to the customers.
- 23 2. For purposes of this docket I recommend the Commission require SCE&G to
24 use its historic 14 percent winter reserve margin. SCE&G has not fully justified
25 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

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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.

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- 1 **Q. How does SCE&G's treatment of generation shortfalls in its planning**
2 **process affect the Company's avoided energy cost calculations?**
- 3 **A. The Company's resource planning process strongly impacts the avoided cost**
4 **calculations. However, the IRP that the Company relies on for its resource plan is**
5 **not typically approved by the Commission, nor revised in response to intervenors'**
6 **testimony. The most recent IRP was filed in February and has not yet received**
7 **Intervenor input or any indication of Commission review. Because the Company**
8 **included the construction of a 540 MW NGCC in 2023 in its most recent IRP, that**
9 **proposed resource is incorporated into the avoided cost calculations. To date, the**
10 **Company has not been required to test a range of scenarios or model the cost of a**
11 **resource plan with DERs allowed to compete with or displace the CC or other**
12 **higher cost resources.**
- 13 This has allowed the company to plan away any generation shortfalls that could
14 be more cost-effectively met with PV or other lower cost resources without
15 explanation. The result is SCE&G builds a higher cost system that does not best
16 serve the needs of the community, and DERs are awarded a lower marginal value
17 than they would have with a more efficiently planned system.
- 18 **Q. How does the Company's peak demand forecast affect its avoided energy**
19 **costs?**
- 20 **A. SCE&G's near term energy forecasts have a significant impact on avoided energy**
21 **and capacity costs by driving the need for generation capacity in its resource**
22 **plans. This generation reduces the value that DERs can provide to the system.**
23 **SCE&G's year-on-year increase in the near term forecasted peak load reflects a**
24 **dramatic increase in demand, as compared to prior years' forecasts. I am**
25 **concerned that this near-term jump is driving long-term planning decisions at a**
26 **significant cost to ratepayers without justification.**
- 27 **Q. What is your recommendation regarding SCE&G's avoided energy cost**
28 **calculations?**
- 29 **A. The Commission should require that SCE&G complete a proper reserve margin**
30 **study, to be finished in time for the 2019 IRP. The Commission should also**

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

8

9 ***Avoided Generation Capacity Calculations***

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

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

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

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

20 **A.** As described in detail in section 3 of this testimony, SCE&G does not utilize the
21 methodology approved in Docket 2017-2-E to calculate the avoided cost of
22 generation capacity. SCE&G instead asserts that resources only have capacity
23 value if they are available in both the summer and winter.²⁹ Furthermore,
24 "because solar does not provide capacity during the winter period, the Company
25 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.

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1 avoided capacity cost of solar for these winter months is zero.”³⁰ The Company
2 cites its Solar Capacity Benefits Study³¹ to support this value.³² However the
3 study does not provide an explanation as to how exactly SCE&G calculated the
4 value of zero or what methodology was used.

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

6 **A. Zero.**

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

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

14 **If SCE&G used the approved methodology to evaluate an updated resource plan**
15 **(with a 14 percent reserve margin), one would expect the avoided generation cost**
16 **to be significantly higher. There are two reasons for this: first, the 540 MW CC**
17 **currently planned for 2023 to meet SCE&G’s winter reserve margin would not be**
18 **needed. Additionally, the system would shift back to summer peaking. Future**
19 **capacity expansion plans would be driven by summer peaking load, which is**
20 **significantly more likely to line up with solar generation. With the summer**
21 **reserve margin set to a minimum of 14 percent, the observed winter reserve**
22 **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)

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

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

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

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

23 A. I believe that SCE&G is already making these estimations. For instance, SCE&G
24 includes five separate years of firm capacity purchases in its 2018 IRP.³⁴
25 SCE&G's inclusion of firm annual capacity purchases in its IRP is a clear
26 indication that SCE&G already has an ability to predict the regional market price
27 for generation capacity. Not only is SCE&G able to forecast the value of selling
28 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.

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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 2017³⁵	SCE&G Purchase 2016³⁶	SCE&G Purchase 2017³⁷	SCE&G Purchase 2018³⁸	SCE&G Purchase 2019³⁹	PJM CT CONE 2018/19⁴⁰
\$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.

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- 1 **Q. What generation capacity value should SCE&G use?**
- 2 A. SCE&G participates in a regional generation capacity bilateral marketplace rather
3 than a wholesale capacity marketplace provided by an RTO such as PJM. Thus,
4 values reflecting SCE&G's recent experience in the local generation capacity
5 bilateral marketplace are instructive. SCE&G procured a bilateral contract for
6 generation capacity for four consecutive years, with an annual increase exceeding
7 the rate of inflation. Absent additional data specific to SCE&G's generation
8 capacity market, I recommend that SCE&G use its capacity purchase price for the
9 years 2017, 2018, and 2019. For the year 2020 and beyond, I recommend
10 applying a forecasted inflation rate to the 2019 generation capacity value. When
11 preparing the 2019 IRP and calculating the avoided cost for next year's docket,
12 SCE&G should gather generation capacity marketplace data to make a 15-year
13 forecast of the value of generation capacity within the region.
- 14 **Q. Please describe the Company's error in failing to include a performance**
15 **adjustment factor.**
- 16 A. In the methodology approved in Docket 2017-2-E, the Company seeks to pay a
17 QF for providing capacity based not on its nameplate rating or expected
18 performance, but rather as a performance payment. In Docket 2017-2-E SCE&G's
19 divides avoided capacity costs (\$6.35 per kW-year) "by the number of critical
20 peak hours in each period...based on 264 critical peak hours in the summer
21 season and...192 critical peak hours in the winter season."⁴¹ SCE&G's approach
22 is to subdivide the hours of the year into summer peak, winter peak, and off-peak
23 and then pay for QF generation capacity on a per kWh basis rather than a per kW-
24 yr basis, depending on the period in which the generation occurs. This approach
25 has merit, because it both simplifies the tariff structure and provides a stronger
26 incentive for the QF to produce power during peak hours when generation
27 capacity is the most valuable.

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

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1 However, this approach must be adjusted if it is to treat QF avoided generation
2 capacity fairly when compared to the Company's own generation capacity. If an
3 SCE&G generator were unavailable for 5 percent of the critical peak hours in a
4 season, the Company would not argue that the generator was no longer fully used
5 and useful as a generation capacity contributor and therefore ineligible for full
6 cost recovery. The same would be true if the same generator was unavailable for
7 10 or 20 percent of the hours in a given year. We expect that utility-owned
8 generators will have forced and planned outages and therefore do not require 100
9 percent availability during critical peak hours as a condition of cost recovery. To
10 ensure that qualifying facilities are not subject to undue discrimination, this
11 principle must also be applied to the QF capacity payments.

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

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

23 A. Yes. For example, Duke Energy Carolinas and Duke Energy Progress use a PAF
24 in both North and South Carolina.^{42,43} In addition, Georgia Power uses an
25 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.

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1 percent performance during key availability hours and still receive full capacity
2 payments.^{44,45}

3 **Q. What PAF value should SCE&G use?**

4 A. A PAF of 1.20 corresponds to an availability factor of 83.3 percent. I would
5 expect that a utility-owned generator with an availability factor of 83.3 percent
6 would be considered used and useful from a generation capacity perspective. A
7 QF with the same performance should be equally compensated for its generation
8 capacity contributions, suggesting that a PAF of 1.20 is appropriate. To the extent
9 that the South Carolina Public Utility Commission would consider a utility-owned
10 generator with availability factor less than 83.3 percent useful, it should consider
11 a PAF even higher than 1.20.

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

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

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

19 2. Include the additional revenue the Company would collect by selling marginal
20 surplus generation capacity contracts made possible by the new QFs in the
21 DRR calculation. Based on known market transactions in the SCE&G
22 territory, the Company should use a capacity value of \$68.62 per kW-yr in
23 2017, \$70.92 per kW-yr in 2018, \$72.38 per kW-yr in 2019, and the 2019
24 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.

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- 1 3. Revise the generation capacity payment split between summer and winter to
2 95 percent summer and 5 percent winter.
3 4. Include a performance adjustment factor of 1.20.
4

5 **6. NET ENERGY METERING METHODOLOGY—2018 APPLICATION**

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

7 A. I believe that the Total Value of NEM Distributed Energy Resources table, as
8 shown in Table 6 of Witness Lynch's testimony, is both incorrect and incomplete.
9 As just discussed in Section 5, the Company incorrectly calculated avoided
10 energy and avoided generation capacity values. These same errors extend to the
11 DER calculations as well. The Company's errors with respect to avoided
12 generation capacity in particular appear to be at odds with a plain reading of the
13 Value of Solar methodology agreed to by parties in the settlement in Docket No.
14 2014-246-E (defining "avoided capacity" as the increase or reduction in fixed
15 costs to the utility "of building and maintaining new conventional generation
16 resources associated with the adoption of NEM"). Now that the Company gives
17 zero capacity value for net metered DERs, these resources have no ability to avoid
18 new capacity.

19 The Company should also include an avoided transmission and distribution
20 capacity value and update its line loss calculations. Finally, SCE&G should
21 evaluate and include a value for avoided environmental costs.

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

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

3 A. The Company should correct its methodologies and calculations for avoided
4 energy in Row 1, avoided generation capacity in Row 2, avoided T&D capacity in
5 Row 4, and avoided line losses in Row 12.⁴⁶ For avoided energy and capacity
6 values, the corrections noted in Section 3 of my testimony should be incorporated.
7 I make further recommendations below for including an avoided transmission and
8 distribution value and for updating line losses. SCE&G should also evaluate and
9 include in future updates an avoided environmental cost value in row 10.

10 *Avoided Transmission and Distribution Capacity Value*

11 **Q. Please explain the avoided transmission and distribution capacity**
12 **component.**

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

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

23 A. No. SCE&G Company Witness Lynch claims that "customer-scale NEM
24 resources are distributed across SCE&G's transmission system and have too small
25 of an impact on any transmission circuit to result in avoided transmission
26 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.

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1 “plan for when the DER is not supplying power,”⁴⁸ the Company must plan as if
2 the resource simply doesn’t exist.

3 I do not agree. These positions entirely overlook the ways that DERs, in the
4 aggregate and on average over time, reduce the need for T&D capacity
5 investments. If the DERs alleviates some of the strain on the system during
6 transmission or distribution system peaks, then those resources do, in fact, reduce
7 pressure on that system and therefore help to defer or avoid future upgrades to
8 that system.

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

11 **A.** Yes. Energy efficiency resources are regularly credited with avoiding or deferring
12 T&D investments.⁴⁹ See the table in DCG-2 (Avoided Cost of Transmission and
13 Distribution Detail) for the results of ACEEE’s survey of avoided costs of T&D
14 for use in energy efficiency program screening. Although there is variation from
15 utility to utility, most of the avoided T&D values are between \$25 and \$75 per
16 kW-year.

17 **Q. How are these values calculated for energy efficiency?**

18 **A.** Methods for quantifying the value of avoided or deferred T&D investments from
19 implementing energy efficiency vary in complexity, cost, and accuracy. In its
20 October 2014 report, the Mendota Group described a range of such methods.
21 More involved methods, such as the system planning approach and rate case
22 marginal cost data with allocators, may provide somewhat more accuracy but at a
23 significantly higher cost than simpler methods. Less resource-intensive methods
24 for quantifying the value of avoided or deferred T&D include: the current values
25 method, which defines the average cost to serve load as each system’s net cost
26 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).

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1 capacity of a representative sample of recent T&D upgrade projects; and the
2 historical/forecast method, which considers whether historical and forecast T&D
3 investments are related to load growth, and weights these investments.⁵⁰

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

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

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

11 A. Yes. Austin, Texas, found a value of 1.0 cents per kWh for avoided transmission
12 capacity cost.⁵¹ In Maine, the PUC adopted a value of 1.6 cents per kWh for
13 avoided transmission capacity.⁵² Avoided distribution capacity was not included
14 in the Maine study because peak loads in the state have been and are forecasted to
15 be generally flat, and thus capacity-related distribution investments were not
16 anticipated. In contrast, SCE&G's 2017 IRP projects peak load to grow
17 significantly over the period of analysis, suggesting that the benefit of avoiding
18 distribution capacity investment in SCE&G's territory is likely to be substantial.⁵³
19 In 2014, the Minnesota Public Utilities Commission approved the structure and
20 methodology for a value of solar (VOS) tariff that utilities can adopt in lieu of net
21 metering. The VOS tariff framework calls for value components to be broken out,
22 including avoided transmission capacity and avoided distribution capacity. In its
23 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.

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1 transmission capacity value of 1.51 cents per kWh and an avoided distribution
2 capacity value of 0.9 cents per kWh for Xcel Energy.⁵⁴

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

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

12 In the absence of more granular data on monthly system peaks, the benefits of
13 DERs in terms of avoided T&D capacity can be approximated using the
14 production profile that SCE&G uses for these resources for capacity planning
15 purposes. The 2017 IRP indicates that the amount of firm solar capacity expected
16 to be available on the system peak hour is 50 percent; other analysis pegs the
17 capacity contribution at 66 percent.^{55,56} If SCE&G expects that the bulk of the
18 newly arriving DER capacity is likely to be solar PV capacity, and assuming that
19 SCE&G's avoided T&D investment is likely to fall in the range of the avoided
20 T&D values found for energy efficiency programs, then SCE&G's QF and DER
21 benefits could be anywhere from \$0 to \$100/kW-year. Considering that most of
22 the avoided T&D values used for energy efficiency programs fell in a narrower
23 range, an avoided T&D value could be between \$12.50 and \$37.50/kW-year if
24 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).

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

8 ***Avoided Line Losses***

9 **Q. What are line losses?**

10 A. Because the wires that deliver electricity have losses, some of the power placed
11 on the transmission system is lost, never arriving to load. This means that for
12 every kWh of electricity that the utility sells it must generate one kWh plus the
13 amount lost in transit. Electricity generated on site from solar PV does not have to
14 travel through the electricity system, therefore the utility does not have to produce
15 this additional electricity lost in transit. Loss values can range from SCE&G
16 reported value of 0.246 cents/kWh over the IRP planning horizon up to more than
17 2.5 cents/kWh,⁵⁷ depending on the system.

18 **Q. Do you find SCE&G’s description of avoided line losses associated with**
19 **DERs adequate?**

20 A. No, I do not. Witness Lynch explained the Company’s approach in detail in the
21 2016 proceeding, requiring four full pages to detail the line loss methodology.⁵⁸
22 His 2018 testimony contains just nine lines.⁵⁹ Because nothing in his 2018
23 testimony suggests a methodological change from 2016, I presume the Company
24 has not changed its methodology for line loss calculation in the past year. While
25 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.

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1 Company appears to have made two important errors in calculating line losses.
2 The Company used annual average system losses as the basis for calculating
3 marginal losses rather than losses associated with the temporal solar profile, and
4 the Company failed to allocate transmission losses as marginal (e.g. twice average
5 loss). These two errors both result in SCE&G failing to credit DERs with the full
6 value of their line loss avoidance.

7 **Q. What are annual average system losses?**

8 A. The annual average system loss is the total MWh of energy lost over the course of
9 the year divided by total MWh of energy placed on the system by the generators.
10 This average does not represent the system loss for a specific hour or system load,
11 but rather the average over 8,760 hours of high load and low load, daytime and
12 nighttime.

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

15 A. Real power losses increase with increased current flow.⁶⁰ This means that the line
16 loss avoidance benefits of a DER are higher during times of high system load than
17 times of low system load. For example, because daytime load is generally higher
18 than nighttime load, solar DERs likely avoid more line losses per kWh of
19 generation than a resource that operates on a full 24-hour basis. Similarly, annual
20 load tends to peak on hot, sunny days—the very hours when solar is producing at
21 highest efficiency.

22 **Q. How should SCE&G calculate system losses?**

23 A. SCE&G should consider the temporal and seasonal nature of solar PV output
24 when determining the line losses that solar DERs avoid. Ideally, SCE&G would
25 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](http://www.pjm.com/~media/training/new-initiatives/ip-ml/marginal-losses-implementation-training.ashx).

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1 MWh were saved each hour due to line loss avoidance induced by solar DERs. To
2 the extent that this approach is overly burdensome, the Company could calculate
3 the average system loss at 100 MW increments, ranging from peak load all the
4 way down to the lowest load of the year. By assigning each hour's demand to a
5 load bin representing a 100 MW range, the Company could determine the line
6 loss avoidance benefits for various levels of load. The use of average annual
7 losses ignores that solar is most productive during periods of higher load and
8 doesn't produce any electricity at all during periods of the lowest load. This likely
9 undercounts the annual system line loss avoidance due to solar DERs.

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

11 **A.** Witness Lynch explains marginal line losses as follows:

12 Marginal losses represent line losses associated with the last few
13 increments or decrements in the system load. As the system load
14 increases on power lines, the losses associated with each increment
15 in load tend to increase and, after a certain point, will increase at
16 an increasing rate. In general, the losses associated with the last
17 MW served will be greater than those associated with the MW just
18 before it. Therefore, marginal losses tend to be greater than
19 average losses and, since NEM DER reduces system loads on the
20 margin, their avoided line losses should be based on marginal
21 losses.⁶¹

22 On the distribution system, SCE&G models marginal losses as "approximately
23 twice average losses."⁶² However, SCE&G models "marginal losses equal to
24 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.

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- 1 **Q. How do you recommend SCE&G's determine marginal line losses?**
- 2 A. SCE&G is correct to double average losses in deriving marginal losses, as it does
- 3 now in calculating marginal distribution system losses. But it doubles the wrong
- 4 average. SCE&G is doubling an average of losses over every hour of the year.
- 5 Solar does not produce electricity over every hour of the year. Solar will not avoid
- 6 losses, for instance, at midnight, so it is incorrect, as SCE&G does, to include
- 7 midnight in the average. To be accurate, SCE&G should calculate the average
- 8 system losses during the hours when solar generates. Then it should double that
- 9 PV-generation weighted average losses to accurately calculate the marginal losses
- 10 for solar.
- 11 When calculating transmission losses, SCE&G currently uses the average line
- 12 loss for all hours of the day, and doesn't double that average to derive marginal
- 13 losses. Instead, it should use an annual system loss average weighted to the PV
- 14 generation profile, and it should double that average transmission loss to arrive at
- 15 the marginal transmission losses avoided by solar PV. Review of the literature^{64,65}
- 16 indicates that "for transmission losses, the marginal losses are always twice the
- 17 average losses."⁶⁶ While it is true that "the amount of losses on the
- 18 transmission/sub-transmission system do not necessarily decrease with load"⁶⁷ in
- 19 a given hour, the system's behavior over the course of a year will behave
- 20 consistently with Joule's first law, resulting in marginal losses double the average
- 21 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-QFweb.pdf.

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

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

2 A. Yes, this is the case for NEM DER resources and QFs eligible for tariff PR-1
3 interconnected to the distribution system. Injecting power directly into the
4 distribution system avoids the need for additional power to overcome losses in the
5 T&D system. Therefore, the avoided energy and avoided generation capacity
6 should be grossed up by the avoided losses on the transmission and the
7 distribution system for these generation resources.

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

15 **Q. Which projects should these loss factors apply to?**

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

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

24 A. Yes. SCE&G asserts it must ensure a reserve margin of 21 percent, representing
25 additional generation capacity beyond the Company's expected annual peak load,
26 in order to ensure reliable supply. DER resources have capacity value, and that
27 capacity value also translates into a reduced reserve margin requirement. The
28 avoided T&D line losses of 8 to 9 percent are quite reliable, and this portion of

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1 avoided generation capacity should be counted towards reducing the level of peak
2 load for which SCE&G should plan.

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

5 **A.** I have four recommendations.

- 6 1. SCE&G should not use straight average annual line losses, but instead use
7 average annual T&D losses weighed to a PV profile to account for solar PV
8 output's correlation with higher load, and therefore higher losses.
- 9 2. SCE&G should recognize that marginal transmission line losses, like marginal
10 distribution line losses, are double the average line loss.
- 11 3. SCE&G should gross up avoided generation and transmission capacity
12 calculations assigned to distribution-level DERs and QFs to reflect the
13 avoided generation and transmission capacity otherwise needed to overcome
14 line losses.
- 15 4. SCE&G should recognize that, in addition to the avoided generation and
16 transmission capacity associated with overcoming line losses, the associated
17 21 percent reserve margin assigned to the generation capacity is also avoided.
18 As such, that too should be reflected in avoided generation capacity
19 calculations assigned to distribution-level DER and QF resources.

20 ***Avoided Environmental Costs***

21 **Q. How should SCE&G proceed with regards to the avoided environmental**
22 **costs not covered by avoided criteria pollutants and avoided CO₂ costs?**

23 **A.** SCE&G states that "at present, there are no environmental costs that are not
24 already included in the other specific components of the methodology."⁶⁸ I
25 disagree with that conclusion. To the extent that distributed energy generators
26 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.

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1 other facilities, those savings should be reflected in the NEM calculation. One
2 example is coal combustion residuals (CCR).

3 On December 19, 2014, EPA issued a final rule regulating CCR under Subtitle D
4 of the Resource Conservation and Recovery Act. The rule applies to new and
5 existing landfills and ash ponds. It establishes minimum siting and construction
6 standards for new CCR facilities, requires existing ash ponds at operating coal
7 plants to either install liners and ground water monitoring or permanently retire,
8 and sets standards for long-term stability and closure care.⁶⁹ NEM resources will
9 result in the reduced dispatch of SCE&G's coal units. The reduction implies less
10 CCR generation, and therefore a potential delay in the need to construct new ash
11 ponds or other CCR facilities. The reduction also suggests less CCR waste
12 generated over the lifetime of the plant, and therefore a reduction in eventual CCR
13 site cleanup costs. These avoided environmental costs are financial, quantifiable,
14 and a direct result of DER generation. As such, savings such as these should be
15 included in Witness Lynch's Table ⁹6, Row 10.

16 **Q. Please summarize your recommendations regarding net energy metering**
17 **methodology—2018 application.**

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

24 **Q. Does this conclude your testimony?**

25 **A.** Yes.

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

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[THE PREFILED SURREBUTTAL TESTIMONY OF
DEVI C. GLICK FOLLOWS AT PGS 414-429 (E-144 - E-159)]

**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

- 1 **Q. Please state your name and business address for the record.**
- 2 **A. My name is Devi Glick. I work at Synapse Energy Economics, Inc., located at**
3 **485 Massachusetts Avenue in Cambridge, Massachusetts.**
- 4 **Q. Have you previously submitted direct testimony in this proceeding?**
- 5 **A. Yes.**
- 6 **Q. What is the purpose of your testimony?**
- 7 **A. The purpose of my surrebuttal testimony is to discuss the rebuttal testimony of**
8 **Joseph Lynch on behalf of the South Carolina Electric & Gas Company**
9 **("SCE&G" or "the Company"), in response to my direct testimony in this docket.**
- 10 **Q. How is your surrebuttal testimony organized?**
- 11 **A. My surrebuttal testimony addresses Company Witness Lynch's comments on the**
12 **following:**

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

11 **1. INTRODUCTION**

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

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

1 2. **WINTER RESERVE MARGIN**

2 *Reserve Margin Methodology*

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

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

10 In my direct testimony, I recommended that "[t]he Commission should require
11 that SCE&G hire an independent firm to conduct an analysis to determine an
12 appropriate reserve margin for both winter and summer. This study should utilize
13 a methodology that balances physical reliability with minimizing economic costs
14 to customers."¹ I also listed several tools and software utilized by peer utilities. I
15 did not recommend any of these specific tools, nor state how the outputs should
16 specifically be used.

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

23 Witness Lynch also referenced a Brattle Group study on the ERCOT region where
24 SERVVM's economic reserve margin didn't meet ERCOT's reliability criteria of
25 an LOLE. His conclusion that, "it therefore appears that SERVVM does not always
26 give a reasonable answer,"² is a valid justification for not taking a reserve margin
27 output by SERVVM 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.

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

10 *System Planning*

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

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

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.

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

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

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

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

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

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).

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

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

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

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

21 To illustrate this, consider a customer with electric resistance heat, a space heater,
22 and a poorly insulated home. Whenever the ambient temperature inside the home
23 drops below 60 degrees, the customer turns his or her heat on. When the outside
24 temperature is quite cold (say below 20 degrees), the customer needs to use a
25 space heater as well. This causes a spike in his or her electricity consumption. If
26 the customer upgrades to a more efficient heating system or has the house
27 weatherized, less electricity will be required to keep the house at 60 degrees, and
28 the supplemental space heater will be used less frequently. This lower trigger
29 temperature would be further outside of the normal distribution of temperature
30 that SCE&G regularly experiences, and therefore would occur less often. The end

1 result would be a decrease in the total amount of electricity needed to heat the
2 customer's home, a decrease in daily peak load, and moderation of extreme
3 weather-related peaks.

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

17 *Reserve Margin's Impact on the Avoided Capacity Cost*

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

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

1 stated "a significant amount of solar capacity is coming onto the system, which
2 alleviates some of the summer capacity needs."⁹

3 ***Reserve Margin's Impact on the Avoided Energy Cost***

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

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

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

20 With a 17 percent reserve margin, no new large capacity additions would be
21 needed until the summer of 2025 at the earliest. The baseload 540 MW combined
22 cycle unit planned for 2023 would not be needed anymore, and the first major
23 capacity need would be pushed back by at least a year and a half. As this analysis
24 suggests, it is very important for the Commission to approve only a reasonable,
25 accurate reserve margin in order to avoid a situation in which ratepayers are
26 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.

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

11 3. AVOIDED CAPACITY COSTS

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

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

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

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

- 1 1. DRR Methodology - The Company appears to have selected a methodology
2 that gives them the answer they want. As discussed extensively by my
3 colleague Dr. Thomas Vitolo in his testimony last year, the difference in
4 revenue requirement methodology is not an industry standard. It is unclear
5 why SCE&G selected it, but what is clear is that it produced the result they
6 wanted to see.
- 7 2. Reserve Margin Study - The assertion that solar does not influence the
8 resource plan is based on the reserve margin study, which shows that SCE&G
9 needs as much capacity in the winter as it does in the summer. As discussed
10 above, this study uses an incomplete methodology and accepts the premise
11 that the system will continue to be winter peaking. This is absolutely not a
12 reasonable assumption. A few extreme winter-peaking days are not
13 justification for massively shifting supply-side planning. What this demand-
14 side risk should prompt is serious consideration of winter demand-side
15 measures as a part of its least-cost resource plan to moderate peaks.
- 16 3. Integrated Resource Plan - SCE&G is using an unapproved Integrated
17 Resource Plan as the basis for its difference in revenue requirement
18 calculations. The Company can plan new thermal resources without
19 justification, and has no mandate to consider demand-side resources or -
20 evaluate which portfolio of resources produces the least cost system.
- 21 Q Witness Lynch claims in rebuttal that SCE&G is using the same avoided
22 capacity methodology previously approved by Commission. Do you agree?
23 Please explain.
- 24 A While it is true that the Company continues to use the DRR method, its
25 methodology for calculating avoided capacity costs is starkly different, as every
26 party in this docket has pointed out. This is a departure from what the
27 Commission approved in past dockets, and also runs afoul of PURPA. A simple
28 illustration demonstrates the perverse outcome of SCE&G's flawed method.

1 SCE&G claims to have *both* a summer and winter capacity need, with its winter
2 capacity need exceeding its summer capacity need. Let's say, for simplicity's
3 sake, that the Company needs 100 MW of summer capacity and 125 MW of
4 winter capacity. SCE&G chooses two capacity resources to meet its needs: one
5 125 MW EE resource that only has value in winter, and one 100 MW solar QF. In
6 the Company's new methodology, the solar QF gets *zero* capacity value, even
7 though it meets a clear summer capacity need, thereby allowing the Company to
8 avoid investing in another capacity resource. Under the Company's new method,
9 only a resource like a natural gas peaking plant that was able to meet both
10 summer and winter capacity needs could get full value. This outcome defies
11 common sense, and does not comply with PURPA's requirement that QFs be
12 given full credit for the costs that they allow utilities to avoid.

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

16 **A.** I do not agree with this, and in fact SCE&G's own planning documents, including
17 its 2018 Integrated Resource Plan, contradict this statement. It is certainly true
18 that solar generators and a combustion turbine with the same nameplate capacity
19 aren't fully interchangeable for reliability planning. However, that hasn't been
20 suggested by anyone in this docket. When discussing a large solar generator on
21 SCE&G's system, Witness Lynch states that "a solar QF does not have firm
22 capacity as it is an intermittent resource."¹² Yet the Company takes a markedly
23 different view in its 2018 Integrated Resource Plan, stating that 35 percent of the
24 865 MW of solar capacity coming online is considered firm capacity.¹³

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.

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

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

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

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

21 A. Witness Lynch states that "DER resources do not result in a reserve margin
22 benefit for the Company."¹⁵ SCE&G's Integrated Resource Plan assigns 35
23 percent of the nameplate of solar capacity to its system capacity calculations,
24 which contribute to its Total System Capacity, Total Production Capability, and
25 hence to its Margin.¹⁶ In other words, for resource planning purposes, SCE&G
26 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.

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

12 4. AVOIDED TRANSMISSION AND DISTRIBUTION COSTS

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

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

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

28 Finally, SCE&G proposed another avoided cost that could be considered "small."
29 According to Witness Lynch's rebuttal testimony, the rate component for avoided

1 criteria pollutants (NO_x and SO₂) is \$0.00008/kwh (15-year levelized). This
2 amount pales in comparison to the examples of avoided T&D costs that I
3 provided in my direct testimony—largely ranging from \$12.50 to \$37.50/kW-
4 year.

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

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

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

14 Company. Witness Lynch states that while SCE&G is currently setting distribution
15 avoided costs to zero, treatment of solar output in distribution planning “may
16 change in the future as SCE&G has more experience with solar QFs on the
17 system.”¹⁷ Witness Lynch made the same assertion last year, and the Company
18 clearly has one more year of experience with solar QFs on its system now.
19 Because of this additional experience, and because avoided costs are quantifiable
20 now, I recommend that the Company be required to commission an independent
21 study of these benefits and file it prior to the next avoided cost filing, so that the
22 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

- 2 Q. How are marginal transmission losses modeled on systems elsewhere and by
3 SCE&G?
- 4 A. The American Transmission Company models marginal transmission losses as
5 “twice the overall average loss.”¹⁸ Similarly, a Federal Energy Regulatory
6 Commission technical report reviewing a transmission system notes that
7 “marginal losses are about twice the average losses.”¹⁹ Consultants and academics
8 also agree that marginal transmission losses are two times the size of average
9 transmission losses.^{20,21} In contrast to these experts, “the Company believes that
10 marginal losses should be approximated by average losses.”²² The Company’s
11 beliefs are inconsistent with both theory and in-the-field application of marginal
12 transmission loss calculations.
- 13 Q. Is SCE&G’s transmission system fundamentally different than other
14 transmission systems in the Southeast, on the Eastern Interconnect, or
15 anywhere else in the contiguous United States?
- 16 A. No. SCE&G’s transmission system, “a network of sources and sinks with power
17 lines connecting them,”²³ is substantially similar to other transmission systems in
18 the region and the country. Therefore, the Commission should require SCE&G to
19 calculate marginal transmission losses as twice average losses, consistent with its
20 industry peers.

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://cepr.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.

1 **6. AVOIDED ENVIRONMENTAL COSTS**

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

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

21 **Q. Does this conclude your surrebuttal?**

22 **A. Yes.**

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.

1 Q Okay. Explain that.

2 A Reserve margins at peer utilities are calculated using
3 methodologies and softwares that balance risk to
4 consumers, so risk meaning demand-side reliability, with
5 cost to consumers. The methodology used by SCE&G relies
6 mostly on just looking at the risk. It does not balance
7 the cost to the customers in the same way that peer
8 utilities do, for example, using SERVIM or other
9 softwares that are available.

10 Q So it's not just the plugging in of the reserve margin
11 into the PROSYM model, it's how they calculated it, as
12 well?

13 A That is correct.

14 Q Okay. And in your response, you have a figure of a 14
15 percent reserve margin. Is that something that you have
16 calculated for SCE&G or something that SCE&G has, in the
17 past, calculated for SCE&G?

18 A Yes, that's their reserve margin that has been used up
19 until this point.

20 Q Okay. For how long?

21 A How long has the 14 percent reserve margin been used?

22 Q Correct.

23 A I am not sure of the history of how many years it's been
24 used for.

25 Q Any guess? Two? More than two?

1 A It's been used in the 2017 and 2016 dockets.

2 Q Okay. Now, that's a summer margin you're talking about,
3 and at the end of the answer you talk about the winter –
4 the observed winter reserve margin never drops below 17
5 percent.

6 A The 14 percent was an annual reserve margin. Up until
7 this year, they did not break out the reserve margin
8 between summer and winter.

9 Q Okay. Are you saying it was an average between summer
10 and winter or between all months or –

11 A Yeah, the 14 percent, I guess, is an average. It's what
12 they use for the entire year. It can be an average or
13 it can simply just be, because the summer was the peak,
14 the summer is when it was binding, so that was when they
15 – that's what they set it based upon, was the summer,
16 but it applied to a whole year.

17 Q Okay. So you believe – is the reserve margin just
18 wherever the peak hits in a year, or a season? Or is it
19 something more than that, that calculation?

20 CHAIRMAN WHITFIELD: Ms. Glick, if you could
21 pull that microphone just – we're having some
22 trouble. I think some folks can't quite hear you.
23 Maybe we can get the volume up a little for you,
24 too.

25 WITNESS: Can you hear me now?

1 **CHAIRMAN WHITFIELD:** We're getting –

2 **WITNESS:** Do you want me to move down there?

3 **CHAIRMAN WHITFIELD:** No, I don't think it's
4 working.

5 **WITNESS:** I can move down there.

6 **COURT REPORTER:** I checked it during the
7 break, but that, of course, doesn't mean for sure.
8 Try pushing the button again.

9 **WITNESS:** [Indicating.] Is that – oh, okay.

10 **CHAIRMAN WHITFIELD:** Now, there you go.

11 **WITNESS:** Sorry, could you repeat the
12 question?

13 **BY COMMISSIONER ELAM:**

14 **Q** Let's see if I can remember now.

15 **A** You were asking about the difference between summer and
16 winter?

17 **Q** Well, is a utility's reserve margin just their peak of
18 the year, regardless of when it is, or is it, to you,
19 some average of the winter peak, summer peak, any other
20 months?

21 **A** The reserve margin is intended to give the utility a
22 kind of margin of error, to allow that, even on the
23 largest day with the most demand they can meet load.
24 And it takes into account variability in weather and in
25 demand. So it is set based on whatever the limiting

1 factor is, so if they have the least amount of capacity
2 available in the winter, then it would be set in the
3 winter; if they have the least amount in the summer,
4 it's set in the summer, depending on when the peak is.
5 It's intended to make sure that the limiting factor of
6 capacity never is too low to meet demand.

7 **Q** Okay. So, to you, it is not just designed every time
8 they hit a new peak sometime, the reserve margin going
9 forward has to be something above that peak. It's a
10 calculation to you, and not just a recognition of
11 whatever peak they may have hit.

12 **A** It is a calculation based to ensure that they always
13 have enough capacity to meet demand at a reasonable cost
14 to customers.

15 **Q** Does that include the ability to purchase, as well as
16 generating capacity, or is it just generating capacity?

17 **A** If they have firm contracts, then it can be included,
18 but it's related to capacity.

19 **COMMISSIONER ELAM:** Okay. Thank you.

20 **CHAIRMAN WHITFIELD:** Thank you, Commissioner
21 Elam.

22 Any other Commissioner questions for Ms.
23 Glick?

24 **COMMISSIONER FLEMING:** Yes.

25 **CHAIRMAN WHITFIELD:** Commissioner Fleming.

EXAMINATION**BY COMMISSIONER FLEMING:****Q** Good afternoon.**A** That afternoon.**Q** It's been a long day, so far. I just – you talked about the need for an independent analysis. And I believe you even said that you felt like the Commission should require an independent analysis. Could you go into – tell us a little bit of your reasoning behind that?**A** Yes. So I looked at what peer utilities in the region have done to calculate their own reserve margins that go into their resource plans and impact rates, and peer utilities in the region – Duke, Southern Company – have used independent analytic companies to conduct analyses and run programs to determine what an optimal reserve margin would be, because these independent contractors do not have a stake in the outcome. They run the numbers and they provide independent, impartial analysis on what an economically optimal reserve margin is to maintain reliability.**Q** Okay. And you also talk about that SCE&G should calculate marginal transmission losses, discuss the transmission losses as it applies to this? Could you go into a little bit more detail?**A** Yes. Could you refer me to what page you're looking at,

1 specifically?

2 **Q** I'm looking at page 15 of your surrebuttal.

3 **A** [Indicating.] Yes. So, my recommendation is that SCE&G
4 calculate transmission losses in a way that meets – of
5 other peers doing these, what the industry recommends.
6 I reference several studies that review methodologies
7 used to calculate transmission losses, and when you look
8 at these same margin losses, they're twice the average
9 loss.

10 **Q** And how does that work into the methodology that you're
11 talking about?

12 **A** So in the table that Witness Lynch presented, the net
13 metering with the ten categories, the avoided
14 transmission cost is one of those categories of avoided
15 costs –

16 **Q** Okay.

17 **A** – that is deferred by putting – if you put solar on a
18 system, it no longer has to go through the distribution
19 lines and the transmission lines and, therefore, you're
20 not losing the energy that has to be produced just to be
21 lost in the process of transporting it to the customer.

22 **Q** Okay. And I think there was some discussion about –
23 it's been a long day, but there was some discussion
24 about figuring the NEM, the 12 points, I believe?

25 **A** The categories? The ten categories?

1 Q Yeah, and that's where you're talking about with the
2 transmission loss?

3 A Yes. It's one of the avoided costs.

4 Q Right. And, okay, so that's where you were also – the
5 avoided cost, you had a question about, with the way
6 they had – I think they had a zero at the avoided cost?

7 A Correct.

8 Q Right. And you disagreed that it should not be zero?

9 A Yes.

10 Q Okay. And have you come up with a figure of what you
11 think it should be?

12 A A number? No. Unfortunately, given the limited time to
13 do the analysis between when the docket came out, I was
14 not able to calculate – do a transmission study and
15 calculate the avoided transmission cost.

16 Q Okay. I think you said you didn't have the evidence
17 that you needed, or did you just get it too late?

18 A So to do a transmission study – to calculate the avoided
19 transmission losses, we would have to do an entire
20 simulation and study, which is something we don't – I
21 don't have the computer programs to do and the ability
22 to do in a short period of time. I could recommend a
23 range from many of the studies that have been done;
24 however, I don't have a specific number that is
25 representative of SCE&G's system.

1 Q Okay. And you had a problem with the methodology they
2 used? Or how they used it? I know Dr. Lynch said they
3 used the same methodology as before, they just – I've
4 forgotten his exact words. It was the way the results –
5 I can't remember. I had that written down somewhere.
6 Oh, a change in results, not methodology.

7 A Are you talking about –

8 Q Do you agree with that, or –

9 A Sorry, I'm confused. Are you talking about the
10 transmission losses or –

11 Q Oh, no, no, no. I'm on to the methodology that they
12 have used to come up with the numbers.

13 A So the methodology to calculate the avoided capacity
14 cost that Dr. Lynch asserts is using the same
15 methodology as last year, it's just different numbers,
16 yes, I do assert that it is, in fact – while they are
17 still using a difference-in-revenue-requirement
18 methodology, the way it's being applied is completely
19 different because, rather than looking at a change in
20 resource plan, what's being asserted is the resource
21 plan can't change because solar cannot avoid any
22 capacity in winter; therefore, no more calculations are
23 required. In my mind, that is a completely different
24 methodology than last year, and there has not been
25 sufficient proof provided to me that the resource plan

1 would be unchanged based on the addition of solar.

2 COMMISSIONER FLEMING: All right. Great.

3 Thank you.

4 CHAIRMAN WHITFIELD: Thank you, Commissioner
5 Fleming.

6 Commissioner Bockman.

7 COMMISSIONER BOCKMAN: Thank you, Mr.
8 Chairman.

9 EXAMINATION

10 BY COMMISSIONER BOCKMAN:

11 Q Good afternoon, Ms. Glick.

12 A Good afternoon.

13 Q In your testimony, you propose that demand-side
14 management can be implemented to reduce peak demands
15 and, perhaps, then reduce or even eliminate the need for
16 additional generation, particularly fossil-fuel
17 generation. Who is it that should control demand-side
18 management programs; the company, or voluntarily – or
19 should the company rely upon voluntary demand-side
20 management by customers?

21 A I would assert that the company should pursue it and
22 look into it as a part of the portfolio of resources.
23 While there always are options for customers to do it
24 themselves, on a dollar-per-kilowatt-hour basis,
25 pursuing energy efficiency and demand-side management is

1 significantly cheaper than building new central
2 resources. And so I think it would be in the company's
3 – it would be a lower-cost resource for the company to
4 pursue demand-side management.

5 **Q** Could the company rely upon voluntary programs by
6 customers? Or is it the responsibility of the company,
7 essentially, to control demand-side management programs?

8 **A** I wouldn't say it is 100 percent the responsibility of
9 the customer, but right now customers have not been
10 pursuing it actively enough to manage the peaks that the
11 company is seeing. And since the company is seeing –
12 the reason the reserve margin is so high is because of
13 increased demand-side risk, because, as Lynch says in
14 his, actually, surrebuttal, inefficient heating, space
15 heaters and resistance heaters, are causing a massive
16 spike in energy use in winter with the decreasing
17 temperatures. And so a small amount of focused
18 investment or effort by the utility to address these
19 thermal winter efficiencies could have significant
20 impact, because not only will it reduce the overall
21 energy use but it will reduce these peaks, because, you
22 know, the temperature at which you would need to turn
23 your space heater on would go down if your house is
24 better insulated.

25 **Q** Are you familiar with utilities who have engaged in

1 those kinds of programs and have realized the kinds of
2 results that you just suggested?

3 **A** There are many, many utilities that have invested in
4 energy efficiency and demand-side measures. The EIA has
5 an 861 form and has an entire database of utility energy
6 efficiency programs, how much they spent on them, how
7 many megawatt-hours of electricity were saved by those
8 programs, and the cost of them.

9 **COMMISSIONER BOCKMAN:** Thank you, Ms. Glick.
10 Thank you, Mr. Chairman.

11 **CHAIRMAN WHITFIELD:** Thank you, Commissioner
12 Bockman.

13 Commissioner Randall.

14 **VICE CHAIRMAN RANDALL:** Thank you, Mr.
15 Chairman.

16 **EXAMINATION**

17 **BY VICE CHAIRMAN RANDALL:**

18 **Q** Ms. Glick, I'm glad we got you mic'd up a little bit. I
19 thought I was going to have to go get my hearing
20 checked. I'd love to hear what you have to say about
21 this: With solar generation being intermittent and the
22 variability of the generation is higher than that of
23 like a fossil-fuel plant and it's not dispatchable, so
24 I'd love to hear what you say about why should solar
25 generation be considered a capacity resource?

1 **A** Yeah, well, SCE&G's current resource plan, which is
2 Exhibit -1 of Witness Lynch's testimony, includes solar
3 and has solar at, actually, 35 percent firm capacity,
4 which is down from 50 percent firm capacity. So the
5 utility itself utilizes a 35 percent firm capacity
6 factor for its own solar. Additionally, having solar in
7 the summer does contribute significantly to peaks in the
8 summer, and with a more reasonable winter reserve margin
9 solar is needed in the summer to reduce peak.

10 **Q** So, your – I missed that part in there where you're
11 talking about a capacity factor of 35 percent?

12 **A** Yes, that's right. So, in the Exhibit -1 that Lynch
13 presented, the IRP, the existing solar that's on the
14 system, that is, the amount that's listed represents a
15 35 percent capacity factor. So the actual nameplate
16 capacity of solar on the system is that number, 35
17 percent of the nameplate.

18 **VICE CHAIRMAN RANDALL:** Okay, thank you, Mr.
19 Chairman.

20 Thank you.

21 **WITNESS:** You're welcome.

22 **CHAIRMAN WHITFIELD:** Thank you, Commissioner
23 Randall.

24 Any other Commissioner questions?

25 [No response]

EXAMINATION**BY CHAIRMAN WHITFIELD:**

Q Ms. Glick, I have one quick one for you. You talk a little bit in your testimony about other utilities that use what you call a PAF, a performance adjustment factor, and I think you cite Duke Energy Carolinas, Duke Energy Progress, and I think Georgia Power, in your testimony. You also, in addition to that, you also kind of advocate for an opportunity cost added to the compensation given the QFs, and you're referencing such things as since they're not producing coal ash or other pollutants in the coal-burning process. Do you know of other states or other utilities in other jurisdictions that have such an opportunity cost as you reference with the PAF? Can you cite other states or other jurisdictions, other utilities, that also have such an opportunity cost that you were maybe referring to?

A So, the opportunity cost is separate from the performance adjustment factor. So, sorry, I'd like to clarify –

Q Correct.

A – which one you're asking me about.

Q Right, and – but you cited – correct, and I do get that. But you cite some examples with the PAF. I'm asking you about the opportunity cost. Do you know of other states

1 or other jurisdictions that do that?

2 **A** That have an opportunity cost? If they're not
3 referenced in my testimony – let me look real quick
4 [indicating].

5 **Q** I mean, an opportunity cost in terms of – because of the
6 fact that they're not producing coal ash or other air
7 pollutants.

8 **A** Well, other states – other utilities incorporate, for
9 example, environmental costs, so the avoided
10 environmental cost of not producing the coal ash, in
11 their avoided environmental component of their net
12 energy metering value. I can't say exactly which ones,
13 but coal ash is a real and quantifiable cost, and the
14 EPA is amending the rule right now on coal ash disposal,
15 so that's definitely included by other utilities in
16 their environmental cost.

17 **CHAIRMAN WHITFIELD:** Well, thank you. I don't
18 see any other Commissioner questions at this time.
19 Ms. Ottenweller, do you have any redirect for your
20 witness?

21 **MS. OTTENWELLER:** No redirect. Thank you, Mr.
22 Chairman.

23 **CHAIRMAN WHITFIELD:** Okay. Well, thank you
24 for your testimony, and you may step down.

25 **WITNESS:** Thank you.

1 **CHAIRMAN WHITFIELD:** Excuse me, and be
2 excused. Not just step down but be excused. We
3 realize you have a time to meet.

4 **WITNESS:** Oh, thank you.

5 [WHEREUPON, the witness was excused.]

6 **CHAIRMAN WHITFIELD:** At this time, if we
7 could, I'd like to ask the company to bring the
8 panel back up and we'll resume cross of the company
9 witnesses.

10 THEREUPON came,

11 **A L L E N W . R O O K S ,**

12 **J O H N H . R A F E R T Y ,**

13 **J O S E P H M . L Y N C H ,**

14 recalled as witnesses, who, having been previously duly
15 affirmed, were examined and testified further as follows:

16 **CHAIRMAN WHITFIELD:** Ms. Ottenweller, I guess
17 you're up, so it's your turn to question the panel.

18 **MS. OTTENWELLER:** Thank you, Mr. Chairman. I
19 know it's been a long day, so I'm going to work to
20 not repeat lines of cross, and just kind of pick up
21 where other folks have left off. And I'm sorry to
22 say that, Dr. Lynch, all of my questions are going
23 to be directed towards you. I know you've had a
24 long day, too.

25 **CHAIRMAN WHITFIELD:** He's had a little break

1 now, so he's ready.

2 WITNESS LYNCH: I'm ready.

3 MS. OTTENWELLER: Ready to go. Okay.

4 WITNESS LYNCH: I'm ready.

5 [Laughter]

6 MS. OTTENWELLER: Let's do it.

7 CROSS EXAMINATION

8 BY MS. OTTENWELLER:

9 Q Dr. Lynch, I want to pick up on a line of questioning
10 about whether the methodology has been changed this year
11 from what was approved in prior Commission proceedings.
12 And I'm going to ask you about a couple of documents
13 that, if I may approach the witness, I'm going to go
14 ahead and hand them out to you at the same time. I'm
15 not entering these in as exhibits, but just for you to
16 have them handy as I'm referring to them and asking you
17 questions. And the first is the company's Motion to
18 Dismiss that was filed in Docket No. 2017-2-E, and
19 Response in Opposition to the Petition filed by CCL and
20 SACE. Are you familiar with that motion?

21 A [LYNCH] Maybe I know it exists.

22 Q Okay.

23 A [LYNCH] And maybe I've read it. I'm not really sure.

24 [Document distributed]

25 Q Okay. I'll give you a copy of that [indicating], just

1 to refresh your recollection on that. And I'd also like
2 to ask you about your direct testimony from last year
3 and your rebuttal testimony from last year. Do you
4 happen to have it handy? I've got a copy if you need
5 it.

6 A [LYNCH] I should have the rebuttal, but not the direct
7 from last year.

8 Q Okay. [Indicating.]

9 A [Indicating.]

10 Q Let me start by asking you about the company's Motion to
11 Dismiss. I want to refer you to page five of that
12 motion, in the middle paragraph. And there is a
13 sentence that starts, "For the reasons identified..."?
14 Do you see that?

15 A [LYNCH] Yes.

16 Q Now, the company says, "For the reasons identified in
17 its December 22, 2017, filing and its prefiled direct
18 testimony, the company believed the Rate PR-2 based upon
19 the previously approved methodology did not properly
20 reflect SCE&G's avoided costs and, therefore, did not
21 propose that rate in Docket No. 2018-2-E." Do you see
22 that?

23 A [LYNCH] Yes.

24 Q Is the company appearing to state there that it did not
25 use the previously approved methodology in the testimony

1 that you filed in this docket?

2 **A** [LYNCH] I guess I'm confused by the question. It's my
3 contention we're using the same methodology, that it's a
4 difference in revenue requirements.

5 **Q** The company's appearing to say here that it did propose
6 a different methodology from what was approved in the
7 prior docket.

8 **A** [LYNCH] PR-2 based on – [indicating].

9 **MR. MUSTIAN:** Mr. Chairman, if I may?

10 **CHAIRMAN WHITFIELD:** Mr. Mustian?

11 **MR. MUSTIAN:** Mr. Chairman, along the lines of
12 my previous objection with the line of questioning
13 by Mr. Snowden, I would object on the grounds that
14 this issue has been ruled upon, is related to the
15 2017 docket, and the Motion to Dismiss is a legal
16 document, not testimony by Dr. Lynch. But, in
17 addition, this issue, again, has been ruled upon by
18 the Commission several times now and we don't
19 believe that it is relevant to these proceedings,
20 or that this line of questioning should not be
21 allowed to proceed.

22 **MS. OTTENWELLER:** Could I respond?

23 **CHAIRMAN WHITFIELD:** Yes, ma'am. Go ahead,
24 Ms. Glick_[sic].

25 **MS. OTTENWELLER:** If it would be helpful, I

1 can defer on this particular question and stick to
2 testimony that the witness himself has filed in the
3 prior docket. I'm willing to do that, if that's
4 helpful. But I think the question of whether the
5 company is proposing new methodology in this docket
6 is a relevant issue to what the Commission is
7 actually being asked to rule on, so I would ask to
8 continue to be able to follow that specific line of
9 questioning. I'm happy to not discuss the 2017 –

10 **CHAIRMAN WHITFIELD:** Well, let me hear from
11 Mr. Mustian.

12 **MR. MUSTIAN:** Mr. Chairman, all I would say is
13 that, in multiple filings with the Commission, the
14 company has been abundantly clear and has
15 repeatedly stated its position that the methodology
16 has not changed. And so to the extent that she's
17 willing to move on and just discuss testimony, then
18 that's one thing, but the company has made its
19 position very clear along those lines.

20 **CHAIRMAN WHITFIELD:** Ms. Glick^[sic], you can
21 contest the methodology in this proceeding.
22 However, this witness probably is not – you went
23 down some line of questioning that he may not have
24 knowledge to. He's said he's not an attorney and
25 he said he's not familiar with some of the legal

1 stances of the company. If you would just stick to
2 the methodology in this proceeding, I think you can
3 continue.

4 MS. OTTENWELLER: Okay. I can move on from
5 that particular question. I would like to ask him
6 about testimony that he submitted in the prior
7 docket on this issue. Would that be permissible?

8 CHAIRMAN WHITFIELD: Yes, his testimony in a
9 prior docket – I think we've already done that
10 today, so, yes, you can stick to his testimony, and
11 I think his testimony was presented to him in the
12 prior docket by another attorney, so, yes, go
13 ahead.

14 MS. OTTENWELLER: Thank you, Mr. Chairman.

15 BY MS. OTTENWELLER:

16 Q Dr. Lynch, I'd like to direct your attention now to the
17 direct testimony that you filed in the 2017 docket,
18 which I handed you. Do you mind turning to page 181?
19 And that's the hearing transcript page. Would you read
20 lines six through nine, the sentence starting, "As
21 stated above..."?

22 A [LYNCH] "As stated above and consistent with the
23 methodology approved by Commission Order 2016-297, SCE&G
24 divides the avoided capacity costs between summer and
25 winter, with 80 percent being associated with the summer

1 season and 20 percent being associated with the winter
2 season. Accordingly, the summer component of avoided
3 capacity cost is \$5.08 per kW-year and the winter
4 component is \$1.27 per kW-year."

5 **Q** So your position in this direct testimony was that the
6 way that SCE&G was splitting capacity at 80 percent
7 summer and 20 percent winter was consistent with the
8 methodology that was approved in the 2016 docket? Is
9 that an accurate characterization of your testimony?

10 **A** [LYNCH] Well, in '16, did we – we split it 80/20, didn't
11 we?

12 **Q** Yes, well, I'm just referring to what you had written
13 here.

14 **A** [LYNCH] Yeah, I'm guessing we split it 80/20 in '16,
15 right, from the – yeah, from the get-go we did it,
16 because we were worried about the winter right from the
17 beginning. So, yes. Yeah.

18 **Q** Can I also refer you to your rebuttal testimony from
19 last year, on page 205, line six. Would you read line
20 six, beginning the sentence, "In last year's fuel
21 hearing..." through the beginning of line 11?

22 **A** [LYNCH] Page 205, line 11.

23 **Q** Line six to line eleven.

24 **A** [LYNCH] Oh, line six. "The company did not err." Can I
25 read that again – no.

[Laughter]

"In last year's fuel hearing under Docket No. 2016-2-E, SCE&G explained and defended its use of the 80/20 percent capacity payment split between summer and winter, respectively. As I testified in that proceeding, this split is based on the relative number of hours that loads fall within 95 percent of their respective seasonal peaks, and this methodology was approved by the Commission in Order No. 2016-297. SCE&G will continue to support this split and the company does not believe the Commission-approved methodology should be modified unless and until new relevant information is available."

Q So, Dr. Lynch, I just want to clarify here, you stated in last year's testimony that this 80/20 split was part of and consistent with methodology that the Commission had then approved. Is that correct?

A [LYNCH] Yeah, but, I mean, you realize, though, that this 80/20 percent split isn't really a calculation of avoided cost; it's more of a pricing mechanism, is the way I think about it.

Q Would you agree that it does have an impact on the avoided-cost payments made to qualifying facilities?

A [LYNCH] Oh, it does. Yes.

Q And you're no longer splitting avoided-cost payments

1 80/20 in this proceeding, correct?

2 A [LYNCH] That's correct.

3 Q Instead, you're paying solar QFs zero for capacity,
4 regardless of their contribution to capacity during the
5 summer?

6 A [LYNCH] Oh, yeah, regardless of – right. It's based on
7 what they – the capacity costs that they avoid, and if
8 avoided cost is zero, that's what they should be paid.

9 Q Would you agree that the Commission – part of what the
10 company is seeking is approval to make this change from
11 the Commission in this proceeding, to move away from the
12 80/20 split and toward this new method?

13 A [LYNCH] Yeah, but I've got to say it's more – I think of
14 it more as a pricing methodology instead of a
15 calculation of avoided cost. But yes, of course, we're
16 looking for the Commission's approval of the new PR-2
17 rate and the PR-1 rate.

18 Q And you are aware that every other party that submitted
19 testimony thinks that this is a dramatic change in
20 methodology? Not just a change, but a dramatic change?

21 A [LYNCH] Oh, the 80/20 is the dramatic – that's the
22 dramatic change?

23 Q The capacity payment changes, in general, that the
24 company is making as part of –

25 A [LYNCH] Or that we believe it's zero now.

1 Q Yeah.

2 A [LYNCH] That they call that a dramatic change. I – yes.
3 Yeah. I've read that, yeah, dramatic change, they
4 thought it was.

5 Q Okay, thank you. Dr. Lynch you answered some questions,
6 previously, about you and your team's involvement in the
7 Integrated Resource Plan. In 2017, your team assigned a
8 50 percent capacity credit for solar resources in the
9 IRP? Are you familiar with that?

10 A [LYNCH] Yes.

11 Q So that means solar's average output during the system's
12 critical times of capacity need was about 50 percent?

13 A [LYNCH] We had estimated, and this was based on the
14 solar profile we had at the Boeing facility, that during
15 the four-hour band from 2 to 6 p.m., in the summer, that
16 about 50 percent of the – well, the kW or the megawatts
17 that were provided on average in that afternoon, those
18 four-hour bands, was about 50 percent of the nameplate.
19 That's why we used that 50 percent.

20 MS. OTTENWELLER: Okay, thanks. I'd like to
21 ask you some questions about the 2018 IRP, if I
22 may, but I'd like to address a procedural matter
23 first.

24 Mr. Chairman, last year in the Commission's
25 denial of CCL and SACE's Petition for

1 Reconsideration in Docket 2017-2-E, the Commission
2 made the point that Petitioners had failed to raise
3 alleged errors during the proceedings. In light of
4 this, I would ask to place a continuing objection
5 on the record concerning the company's reliance on
6 its 2018 Integrated Resource Plan as a foundation
7 for its avoided-cost calculations.

8 **CHAIRMAN WHITFIELD:** Objection so noted.

9 **MS. OTTENWELLER:** Thank you.

10 **CHAIRMAN WHITFIELD:** And we will take judicial
11 notice of it, and rule in the final order.

12 **MS. OTTENWELLER:** Thank you very much. Am I –
13 I've still got –

14 **CHAIRMAN WHITFIELD:** Five more minutes.

15 **MS. OTTENWELLER:** Okay. I would like to enter
16 the 2018 IRP into evidence, and I have copies of
17 that.

18 [Document distributed]

19 **CHAIRMAN WHITFIELD:** Okay, Ms. Ottenweller,
20 we'll enter the 2018 IRP in as Hearing Exhibit No.
21 9. I don't see any objections from anyone, so
22 we're going to enter that in as Hearing Exhibit
23 No. 9.

24 [WHEREUPON, Hearing Exhibit No. 9 was
25 marked and received in evidence.]

1 BY MS. OTTENWELLER:

2 Q Dr. Lynch, do you recognize this document as the
3 company's 2018 Integrated Resource Plan?

4 A [LYNCH] Yes, I do.

5 Q This has been premarked as SACE-CCL Cross-Examination
6 Exhibit 1, and I had some questions on this. So, this
7 year your team is using a 35 percent capacity factor for
8 solar resources?

9 A [LYNCH] Yeah, more like a capacity ratio. A capacity
10 factor is usually something else, but, yes, 35 percent.

11 Q Could you explain the differences between a capacity
12 factor and a capacity –

13 A [LYNCH] Well, a capacity factor is used throughout the
14 industry, and it represents the percentage of energy
15 that a unit would produce relative to what it could
16 produce if it ran 8760 – you know, maximum. But I can
17 work with your term if that's better, but it's more like
18 a ratio. It's a firm ratio.

19 Q So as far as the company's resource plan is concerned,
20 you are continuing – you've lowered the firm capacity
21 for solar generation from 50 percent to 35 percent, but
22 you continue to believe that there is a firm capacity
23 value to the system from those resources?

24 A [LYNCH] Yeah, we're estimating that 35 percent of their
25 nameplate rating we could give it a capacity value in

1 the summer, you know, to help with the peak load. We
2 had 50 percent last year, and I also remember Dr. Vitolo
3 last year had a study where SACE was claiming – they had
4 a big study saying it was 70 percent of the total.
5 Anyway, I was surprised, because I thought we were going
6 to argue about this, too, this year.

7 Q We can, if you'd like.

8 A [LYNCH] Yeah, because we're estimating it. What's the
9 value, what does solar do in the summer afternoon. If
10 it did 70 percent, that would double how much summer
11 capacity would be on the system and then there'd be no
12 question. See like right now, with the 865, we're
13 showing that solar is providing 302 megawatts. Had we
14 said 70 percent, then it'd be 604 megawatts in the
15 summer. And then, without question, there'd be no doubt
16 in anybody's mind, I wouldn't think – even Mr. Horii –
17 that we need capacity in the winter, because the solar's
18 covering all this capacity in the summer, if you see
19 what I mean. So right now I'm thinking the 35 percent
20 is the better number, but, you know, as we estimate this
21 stuff and do more analysis, hopefully, we're free to
22 change it if we get more solar on the system and
23 calculate new numbers.

24 Q But regardless of the 35 percent capacity value that
25 you're giving to solar in the IRP, when it comes to

1 PURPA qualifying facilities in this docket, they will
2 receive no capacity payments during any period of the
3 year, under the methodology that you're seeking to get
4 approved.

5 A [LYNCH] It doesn't sound to me like you said that
6 exactly right. The 875 megawatts of solar capacity
7 that's under power purchase agreements now, they all get
8 capacity payments. From the 875, going forward, the
9 next 100 megawatts of solar, the company argues they
10 should not get an avoided capacity payment because they
11 don't avoid any capacity on the system.

12 Q But you are attributing a capacity factor to those
13 additional resources, even though you're not providing
14 them with a capacity payment, correct? That additional
15 100 megawatts, didn't you find –

16 A [LYNCH] Oh, there –

17 Q – 19.5 percent?

18 A [LYNCH] Yeah, but think of – what I hear you arguing,
19 you said so this next 100 megawatts of solar, the 875,
20 and now you add another 100 megawatts of solar, it will
21 show some capacity with some effect or benefit on the
22 summer peak, but it won't do anything on the winter
23 peak. So if we have to build capacity for the winter
24 and it's there for the rest of the year, even for the
25 summer, there is no avoided capacity. If we have to

1 build the capacity, we're not avoiding it, then no
2 matter what the solar does, you wouldn't pay, then, the
3 avoided capacity cost. Right?

4 Q You've identified that you have both a summer capacity
5 need and a winter capacity need, correct?

6 A [LYNCH] That's correct.

7 Q But you're asserting that the winter capacity need is
8 larger based on the reserve margin study that you've
9 done.

10 A [LYNCH] That's correct.

11 Q What would prohibit the company from choosing one
12 capacity resource, such as a winter DSM program, to meet
13 its winter capacity need, and another capacity resource,
14 like a solar qualifying facility, to meet its summer
15 capacity needs?

16 A [LYNCH] Well, I would suppose, nothing.

17 Q In that case, wouldn't both of those resources be
18 avoiding cost to the company?

19 A [LYNCH] Well, if you had – and what we propose to do is
20 to have a demand-response program to clip the peaks in
21 the winter. If we had that, and then – and enough of
22 it, so the 100 megawatt wasn't enough for 21 percent,
23 but Mr. Horii, based on his calculations, it was 18
24 percent you'd start showing – at 18 percent, if you
25 could cover a couple of percentage of need with the

1 demand-response program, the 100 megawatts, if we got
2 that into place, then at a future time in the future
3 we'll need summer capacity, and then solar would – if it
4 came in to provide summer capacity, helped us avoid cost
5 in the summer, it may have value then, depending on this
6 program. Am I saying that right?

7 **CHAIRMAN WHITFIELD:** Ms. Ottenweller, do you
8 have a good bit more of cross?

9 **MS. OTTENWELLER:** I'd say maybe 10 or 15
10 minutes.

11 **CHAIRMAN WHITFIELD:** I think we're going to
12 break here now, and let you resume with this panel
13 in the morning, and we will follow that with ORS
14 and Commissioner questions of this panel. And we
15 will resume back at 10 a.m., in the morning.

16 [WHEREUPON, the witnesses stood aside.]

17 **MR. BURGESS:** One administrative matter. INPO
18 is on-site at V.C. Summer this week, and George
19 Lippard needs to get back out to the plant. Would
20 you mind if he is excused for the remainder of the
21 hearing?

22 **CHAIRMAN WHITFIELD:** I don't see any
23 objections, and Mr. Lippard has already testified
24 and done cross. So, certainly – I don't see an
25 objection to – Mr. Lippard can be excused, and

1 certainly understand that. And you're excused, Mr.
2 Lippard.

3 [WHEREUPON, Witness Lippard was excused.]

4 **MR. BURGESS:** Thank you, Mr. Chairman.

5 **MR. LIPPARD:** Thank you from the bottom of my
6 heart.

7 [Laughter]

8 **CHAIRMAN WHITFIELD:** I can tell you really
9 want to be there.

10 See you at 10 a.m.

11 [WHEREUPON, at 5:55 p.m., the hearing in
12 the above-entitled matter was adjourned,
13 to reconvene at 10 a.m. on April 11,
14 2018]

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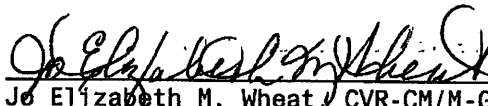
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C E R T I F I C A T E

I, Jo Elizabeth M. Wheat, CVR-CM-GNSC, Notary Public in and for the State of South Carolina, do hereby certify that the foregoing is, to the best of my skill and ability, a true and correct transcript of proceedings had and testimony adduced in a hearing held in the above-captioned matter before the PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA;

That the witnesses appearing during said hearing were affirmed by me to state the truth, the whole truth, and nothing but the truth;

IN WITNESS WHEREOF, I have hereunto set my hand and seal, on this the 6th day of July, 2018.


Jo Elizabeth M. Wheat, CVR-CM/M-GNSC
Hearings Reporter, PSC/SC
My Commission Expires: January 27, 2021.

**BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
COLUMBIA, SOUTH CAROLINA**

HEARING #18-11716 APRIL 11, 2017 10:00 A.M.

DOCKET NO. 2018-2-E:

*SOUTH CAROLINA ELECTRIC & GAS COMPANY – Annual Review of Base
Rates for Fuel Costs*

**TRANSCRIPT OF TESTIMONY
AND PROCEEDINGS**

VOLUME 2 OF 2

COMMISSION MEMBERS PRESENT: Swain E. WHITFIELD,
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P R O C E E D I N G S

CHAIRMAN WHITFIELD: Please be seated. I will call this hearing back to order. And Mr. Burgess, Mr. Mustian, if y'all will – Mr. Gissendanner – bring your panel back? I believe Ms. Ottenweller still had, I think she said, 15 or 20 minutes' worth, or so, of questioning. So, if you will bring your panel back up?

MR. MUSTIAN: Glad to, Mr. Chairman.

CHAIRMAN WHITFIELD: And I will remind them they are still under oath.

THEREUPON came,

A L L E N W . R O O K S ,

J O H N H . R A F T E R Y ,

J O S E P H M . L Y N C H ,

recalled as witnesses, who, having been previously duly affirmed, were examined and testified further as follows:

CHAIRMAN WHITFIELD: Okay, Ms. Ottenweller, we'll turn it back over to you.

FURTHER CROSS EXAMINATION

BY MS. OTTENWELLER:

Q Good morning. Dr. Lynch, let me know when you're ready to get started.

A [LYNCH] Okay. I'm ready.

1 Q All right.

2 A [LYNCH] Let's go.

3 Q All right. Dr. Lynch, when we left off yesterday we
4 were discussing the 2018 IRP, and I'd like to pick back
5 up there.

6 A [LYNCH] Yes, ma'am.

7 Q Yesterday, you agreed that solar qualifying facilities
8 reduced the system's summer peaks, correct?

9 A [LYNCH] Yes, they help out in the summer. Yes.

10 Q And in your direct testimony, you have an attachment,
11 the Capacity Benefit Study. Are you familiar with that
12 document?

13 A [LYNCH] Yes.

14 Q On page five of that document, you say, for five months
15 of the year, solar impacts peak demands on most days of
16 the month and all the days in June and July. Do you
17 recall that?

18 A [LYNCH] That was on page five of —

19 Q The Capacity —

20 A [LYNCH] — JML-4?

21 Q — Benefit Study, which I think is JML- —

22 A [LYNCH] Page five. And, I'm sorry, what were you
23 quoting?

24 Q So it says, for five months of the year, solar impacts
25 peak demand on most days of the month and all days in

1 June and July.

2 A [LYNCH] Oh, uh, yes. You're leaving out the winter;
3 that's what's throwing me.

4 Q Right, yeah.

5 A [LYNCH] Okay.

6 Q Yeah, five months of the year.

7 A [LYNCH] Maybe you're getting to that. I'm sorry.

8 Q And SCE&G identifies both a summer capacity need and a
9 winter capacity need, correct?

10 A [LYNCH] That's correct.

11 Q So the company will need to procure capacity resources
12 to meet both those identified seasonal needs over the
13 next 15 years?

14 A [LYNCH] Well, whatever capacity it procures would have
15 to help serve the load, summer and winter, and the rest
16 of the hours and days of the year. For example,
17 combined-cycle for example, or combustion turbine or
18 some of those, it may meet the immediate need of the
19 winter but it would help in the summer, as well. You'd
20 use it year-round.

21 Q Do you remember what day your direct testimony was filed
22 in this docket?

23 A [LYNCH] I –

24 Q Subject to check –

25 A [LYNCH] – suppose I should. I don't know. But you –

1 Q – February 23rd?

2 A [LYNCH] – probably know better than me. Okay, February
3 23rd.

4 Q Okay. And the 2018 IRP was not publicly filed at that
5 time, right?

6 A [LYNCH] The 28th is when we file each year.

7 Q Would you agree that the company's 2018 IRP had not been
8 analyzed or reviewed by this Commission?

9 A [LYNCH] No, I don't know what the Commission – I don't
10 know.

11 Q You don't know if they – okay. But it's your
12 understanding that the IRP is not binding on the
13 company, right?

14 A [LYNCH] We offer it up as sort of information. We think
15 of it as an information filing, and so the plan we put
16 in there we feel is reasonable but it's not – they don't
17 represent decisions.

18 Q So SCE&G can make any changes it likes to that plan.

19 A [LYNCH] Well, within the normal restrictions on us. I
20 mean, we can't do anything. For example, if we wanted
21 to build a power plant, we would have to come to the
22 Commission to get a certificate of public convenience
23 and necessity. So we're not free to do anything we
24 want.

25 Q Sure. So the resource decisions that you list in JML-1,

1 on the spreadsheet, those are not really commitments?

2 A [LYNCH] Well, some of them are commitments, right? Some
3 are settled. So, for example, 865 – well, 875 now, but
4 in that document – 865 megawatts of solar are currently
5 under power purchase agreements, so the company has
6 signed a commitment, so that's something of a done deal.
7 The Carolina Energy Center, the 540 megawatts of
8 combined-cycle, I don't know if it's a done deal, but
9 it's close. I don't know what else has to be done, but
10 that's sort of set, in my mind, I think.

11 Q But the 540-megawatt CC in 2023, that's –

12 A [LYNCH] Right, that's not –

13 Q – not a commitment at this time.

14 A [LYNCH] – a commitment. That can change. And more
15 studies will have to be done before the company decides
16 – at least, that's my understanding. I don't make the
17 decisions. We analyze the numbers and make
18 recommendations. But my understanding's that this can
19 change and that more work has to be done to evaluate it.

20 Q Okay. But that non-binding commitment, or non-
21 commitment, made in the IRP for that CC, that does feed
22 into avoided cost rates, right?

23 A [LYNCH] Yes. So the way it comes about is we make a
24 forecast of summer and winter peak demands – and this is
25 where I think, I would expect, most utilities work this

1 way, is you forecast the peak demands, you look at what
2 resources you have; reserve margin, what you need. And
3 you figure out what that gap is, that you have a
4 shortage of capacity. And then you first meet that
5 shortage with the cheapest form of capacity you can
6 find. So, typically, we put in combustion turbines.
7 And so when we came up with this plan, that's what we
8 did, and I think we had – one plan had three combustion
9 turbines or four combustion turbines, and then you go
10 through some iterations and think, well, that's the
11 cheapest form of capacity, and it's cheaper to build a
12 combustion turbine than it is a combined-cycle, but a
13 combined cycle is more efficient. So then you run
14 studies and say, well, the energy value that comes from
15 a combined-cycle, the energy savings that we'd have by
16 putting a combined-cycle instead of several combustion
17 turbines, does that outweigh the incremental capacity
18 cost of a combined-cycle? So we run several studies and
19 whittle it down. And what we found out – at least, on a
20 preliminary basis – that putting a combined-cycle in, in
21 2023, is better than putting in several combustion
22 turbines throughout the 15-year horizon.

23 But the amount of capacity is sort of dictated by
24 the peak-demand forecast, the existing capacity
25 commitments, and the reserve margin, and you figure out

1 what the gap is. So that's sort of the process we went
2 through, and that's why the 540 is put in the IRP. So
3 it's a reasonable thing, but it's not a commitment – I
4 mean, the company hasn't decided. It's not a ridiculous
5 plan, but, I mean, we have to do more work.

6 **Q** So would you agree that, in essence, these non-binding
7 plans create the foundation of cost that the company
8 uses as inputs to decide which actual costs a QF will
9 avoid?

10 **A** [LYNCH] Let me put it in my words, but I think this is
11 what you're getting at. So to calculate the avoided
12 energy cost, for example, the avoided energy cost is –
13 we use this resource plan and then we calculate a – we
14 figure a change plan where, in this case, we put in a
15 solar profile. So assuming we have – well, the 865
16 megawatts, that's set, PPAs. Then we say, "Well, the
17 next 100 hundred megawatts of solar, if we add another
18 100 megawatts of solar to the system," here's my base
19 plan, my change plan with this purchase, "what's the
20 savings in production costs?" Well, those savings,
21 which we estimate through PROSYM model and we run the
22 ten scenarios because of the randomness and that sort of
23 thing, that's how we come up with the avoided energy
24 cost. Maybe I should add, too, at the same time that,
25 if you move some of these units around, I don't think

1 the avoided energy cost would change very much. They're
2 pretty robust. I believe. I believe. But, yes, it's
3 dependent on the resource plan. If you change the plan,
4 the avoided costs would be a little bit different. I
5 don't doubt that.

6 Q Okay. The 2018 – we talked about this combined-cycle
7 that's currently in the plan for 2023. In its IRP, did
8 the company present any results demonstrating that the
9 CC would actually be the least-cost capacity addition?

10 A [LYNCH] I don't believe – I'm trying to think did
11 someone in management want to see it? I know my team
12 and I talked about it. The people who run the study, we
13 talked about it. I believe we talked to our boss, my
14 boss, about it. I'm not sure. But I don't think – I'm
15 not sure there was a big discussion. No, there's – no,
16 let me take that back. I have a senior engineer who
17 really runs a lot of the numbers, he's a PROSYM expert.
18 And he's on a team at the company – he's representing
19 Resource Planning on the team with the fossil/hydro and
20 the gas people. So I'm thinking that team, which also
21 had the vice president of Fossil/Hydro – yeah, so I'm
22 sure there was a discussion over there. But it didn't –
23 I don't believe it rose – I didn't bring – my team
24 didn't bring something to senior management for approval
25 and presentation.

1 Q Okay. And there's nothing in the actual IRP document
2 that demonstrates these cost analyses?

3 A [LYNCH] I don't — I'm pretty sure no. I think no.

4 MS. OTTENWELLER: I'd like to enter an exhibit
5 into evidence, a discovery response, and I'm
6 premarking this SACE-CCL Cross Exhibit 2.

7 [Document distributed]

8 CHAIRMAN WHITFIELD: Ms. Ottenweller, do you
9 want to go ahead and enter this in? Is that what
10 you're saying?

11 MS. OTTENWELLER: Yes, I would.

12 CHAIRMAN WHITFIELD: All right. We're going
13 to enter this — I'm going to call it Request 19, if
14 that's okay. We're going to enter it in as Hearing
15 Exhibit No. 10.

16 [WHEREUPON, Hearing Exhibit No. 10 was
17 marked and received in evidence.]

18 MS. OTTENWELLER: Thank you, Mr. Chairman.

19 BY MS. OTTENWELLER:

20 Q Dr. Lynch, does this appear to be a discovery response
21 that was produced —

22 MR. MUSTIAN: Mr. Chairman, if I could?

23 CHAIRMAN WHITFIELD: Yes, sir.

24 MR. MUSTIAN: I apologize.

25 CHAIRMAN WHITFIELD: Yes, sir, if you could go

1 to a microphone, Mr. Mustian.

2 MR. MUSTIAN: Mr. Chairman, I apologize for
3 the late comment, but on the second page of that
4 document, there's a portion of that that has been
5 identified as confidential information related to a
6 purchase, and —

7 MS. OTTENWELLER: Oh, I'm so sorry. I did not
8 catch that last night.

9 MR. MUSTIAN: So, if I could just have one
10 second?

11 CHAIRMAN WHITFIELD: Yes, you can.

12 [Brief pause]

13 MR. MUSTIAN: Mr. Chairman, I think there,
14 obviously, are some parties that have not signed a
15 confidentiality agreement, and they should not
16 really be privy to this information. So I really
17 think it would be appropriate to take the documents
18 back up that she has passed out. If she wants to
19 redact out that information, I think we can work
20 with her on that. But this particular information,
21 the company does deem and asserts its
22 confidentiality protection.

23 CHAIRMAN WHITFIELD: Ms. Ottenweller, I am
24 going to probably have to ask that you do that.

25 MS. OTTENWELLER: Yes.

1 **CHAIRMAN WHITFIELD:** Now if you want to still
2 enter it, we will have to ask that you redact the
3 portion that Mr. Mustian has referred to on the
4 second page.

5 **MS. OTTENWELLER:** I can absolutely do that.
6 And my cross questions are actually not pertaining
7 to that confidential information, so I think that I
8 can ask these questions and actually probably not
9 enter it into evidence, and just –

10 **MR. MUSTIAN:** Well, and I don't necessarily
11 have a problem with that. I think that the next
12 point then would be the copies that have been
13 distributed to the other parties that have not
14 signed a confidentiality agreement, that those need
15 to be collected –

16 **MS. OTTENWELLER:** Yep.

17 **MR. MUSTIAN:** – so that they're not
18 distributing confidential information.

19 **MS. OTTENWELLER:** I agree with that.

20 **MR. ELLIOTT:** I think I'm the only party, and
21 I gave mine, over here, to this party that had
22 signed the agreement. So I'm good.

23 **CHAIRMAN WHITFIELD:** Yeah. We're not. Mr.
24 Mustian, are you okay with it still being entered
25 in as an exhibit? I made it Exhibit No. 10. Or

1 would you like it to be entered – as long as it's
2 redacted, are you okay with it still being entered
3 in as a hearing exhibit?

4 MR. MUSTIAN: Well, Mr. Chairman, not to speak
5 for her, I understood Ms. Ottenweller to say that
6 she was not going to enter it in as an exhibit and
7 that she would just ask questions based on that
8 document.

9 MS. OTTENWELLER: I believe that I can do
10 that. I think that would be the easiest way to do
11 it.

12 CHAIRMAN WHITFIELD: Well, if you can do that,
13 we're going to take it off as that hearing exhibit,
14 and we'll hold that number for the next exhibit,
15 should one come up, but we're going to retract that
16 Hearing Exhibit 10 and it's no longer in the
17 record.

18 [Hearing Exhibit No. 10 withdrawn]

19 MR. MUSTIAN: Thank you, Mr. Chairman.

20 BY MS. OTTENWELLER:

21 Q Okay. Dr. Lynch, what I'm going to do is I'm going to
22 limit my questions on this particular exhibit to the
23 non-confidential portions, and if at any time you
24 believe that we're straying into confidential territory,
25 just let me know. But I'm going to be limited to

1 Responses E and F, which are not designated confidential
2 on this handout. The Request E asks what modeling tools
3 and software the company used on this spreadsheet that
4 you presented as part of the IRP, your attachment JML-1.

5 A [LYNCH] [Nodding head.]

6 Q It also asked which resource options were allowed to be
7 selected by these modeling tools in order to produce a
8 least-cost resource portfolio. Do you see that?

9 A [LYNCH] Yes.

10 Q Would you read the company's response on the next page,
11 paragraph (e)?

12 A [LYNCH] Okay. So, paragraph (e) says, "The unit
13 dispatch simulation model, PROSYM, and a fixed cost
14 Excel spreadsheet model were used to develop the
15 resource plan shown in Exhibit JML-1. These tools were
16 used to choose between peaking turbines and combined-
17 cycle plants."

18 Q So you talk about two models, and one is PROSYM, which
19 creates the avoided energy rates, correct?

20 A [LYNCH] Correct.

21 Q The other one is an Excel spreadsheet which informs
22 capacity rates?

23 A [LYNCH] It calculates the capital costs of capital
24 investment, so it has embedded in it fixed charge
25 schedules, rates of return, you know, capitalization,

1 everything that goes into a fixed charge schedule.

2 **Q** So I want to focus on that capacity-related model.
3 First, the company did not use any optimization or
4 simulation software in making that long-term capacity
5 plan, correct?

6 **A** [LYNCH] That's correct.

7 **Q** So that means there was no use of sophisticated modeling
8 that could integrate various resources and select the
9 optimal least-cost generation resource?

10 **A** [LYNCH] Well, we did not use an optimization model, no.

11 **Q** Okay. Are you familiar with any other utility that uses
12 an Excel spreadsheet for its IRP capacity plan, rather
13 than an optimization model?

14 **A** [LYNCH] I'm sure they all use Excel, but I don't know
15 what other utilities are doing specifically.

16 **Q** Okay. And yesterday, Mr. Snowden asked you about your
17 familiarity with FERC regulations and orders. Do you
18 recall that?

19 **A** [LYNCH] Mr. Snowden asked me about FERC – yeah. Oh,
20 yeah, yeah, I think so. Yes.

21 **Q** Okay. I want to ask you about one particular order to
22 gauge your familiarity with it, on this particular
23 issue.

24 **MS. OTTENWELLER:** May I approach the witness?

25 **CHAIRMAN WHITFIELD:** Yes.

1 BY MS. OTTENWELLER:

2 Q [Indicating.]

3 A [LYNCH] [Indicating.]

4 COMMISSIONER BOCKMAN: Mr. Chairman, may I
5 inquire of counsel if she has copies for us to
6 follow?

7 CHAIRMAN WHITFIELD: Certainly, Commissioner
8 Bockman.

9 MS. OTTENWELLER: Certainly, I do.

10 CHAIRMAN WHITFIELD: If you could share those,
11 that would be nice.

12 [Document distributed]

13 BY MS. OTTENWELLER:

14 Q I've handed you an excerpt from Order 69 that was issued
15 by FERC in 1980. Are you generally familiar with this
16 order? I know it's very long.

17 A [LYNCH] Probably not, but —

18 Q Okay. I want to direct your attention to the second_[sic]
19 page that I handed you, page 12,216, and I've
20 highlighted a portion of that on the third column,
21 halfway down, starting with, "One way..." I'm going to
22 read a portion of that and ask you a couple of questions
23 about it. It says, "One way of determining the avoided
24 cost is to calculate the total capacity and energy costs
25 that would be incurred by a utility to meet a specified

1 demand in comparison to the cost that the utility would
2 incur if it purchased energy or capacity or from a
3 qualifying facility to meet part of its demand and
4 supplied its remaining needs from its own facilities.
5 The difference between these two figures would represent
6 the utility's net avoided cost. In this case, the
7 avoided costs are the excess of the total capacity and
8 energy cost of the system developed in accordance with
9 the utility's optimal capacity expansion plan..." Does
10 that sound like the DRR method that the company is using
11 to calculate avoided costs, that description I just
12 read?

13 A [LYNCH] I guess it sounds like it.

14 Q Okay. I want to direct your attention to Footnote 6. I
15 know it's very small text, but it says, "An optimal
16 capacity expansion plan is the schedule for the addition
17 of new generating and transmission facilities which,
18 based on an examination of capital, fuel, operating, and
19 maintenance costs, will meet a utility's projected load
20 requirements at the lowest total cost"?

21 A [LYNCH] Yes.

22 Q So you have stated that you are using the DRR method,
23 correct?

24 A [LYNCH] Difference in revenue requirements, yes.

25 Q But you're not using optimization software as part of

1 your integrated resource planning?

2 A [LYNCH] Well, I don't think you need optimization
3 software to come up with an optimal plan. I think our
4 plan is very – if it's not optimal – whatever that, you
5 know, is – it's very close to optimal. And that's why
6 we did this – we – to come up with the plan we have to
7 choose a combined-cycle, for example, we ran studies to
8 first see if a combustion turbine would work, since
9 that's the cheaper form of providing capacity. Now, in
10 the plan, though, too, when we come to the combined-
11 cycle, I'm sure we're looking to market to make
12 purchases; there are purchases in the plan that pushes
13 out the need to expend capital. But as a matter of,
14 well, least practicality, I don't think you can make a
15 purchase that's going to last forever. If you have a
16 long-term capacity need, I think the company would want
17 a plant there, as opposed to a purchase. And, of
18 course, we wouldn't postulate any more solar, because
19 those are QFs and we have to take whatever solar shows
20 up, so there's no sense in having to go beyond that. So
21 I'm thinking our plan, even the one in the IRP which I
22 say needs more work, I want to study it more before –
23 certainly, before the company brings it before the
24 Commission, we have to run studies. My contention is
25 that this is very close to optimal. This is a good

1 plan.

2 **Q** When it comes to evaluating future capacity needs in an
3 IRP, would you agree that a full range of capacity
4 resources should be considered to determine what will
5 provide power most cost-effectively for customers?

6 **A** [LYNCH] Well, I hate to disagree with that, but some
7 sources of generation aren't practical. For example, we
8 didn't consider any more coal units. Right now, I don't
9 think that's on anybody's list of potential capacity
10 expansion. And it may be cheaper than a combined-cycle
11 – I'm probably sure it's not, but – so, considering
12 everything, it's not reasonable, I don't believe.

13 **Q** So, in your spreadsheet model, you only actually analyze
14 two resource options for meeting that capacity need: a
15 peaking turbine and a combustion-cycle plant?

16 **A** [LYNCH] The Excel spreadsheet model calculates the
17 capital costs, as I said. So you put a plant in, and
18 you'd say a combustion turbine in whatever year, the
19 fixed charge schedule would give you the revenue
20 requirements for every year of the life of that plant,
21 so you'd have a string of costs going out 50, 60 years,
22 or something of that sort, and the spreadsheet model
23 would calculate the present worth of all that revenue
24 requirement. So we use the Excel spreadsheet in tandem
25 with PROSYM. So you come up with a plan, PROSYM would

1 give us the production costs, the Excel spreadsheet
2 would give the capital costs, and we put them both
3 together to get the total costs of the plan.

4 **Q** Now you state, in your response, that these modeling
5 tools were used to choose only between peaking turbines
6 and combined-cycle plants.

7 **A** [LYNCH] Yeah, when we look forward, I mean, to the
8 future and how are we going to meet the capacity needs
9 on our system, essentially, I think our options are
10 limited to combustion turbines and combined-cycles; gas-
11 fired plants, I think, is our only options.

12 **Q** And those are the only options that you modeled in your
13 spreadsheet.

14 **A** [LYNCH] That's correct. Except for – we have energy
15 efficiency programs, demand-side management, so all of
16 that is embedded in there.

17 **Q** Right, but those, you picked a certain amount of that,
18 you baked that into earlier years, but as far as the
19 capacity need that you have in 2023, you were just
20 looking at those two options.

21 **A** [LYNCH] Well, no, we take our existing energy efficiency
22 plans and make a projection of what we think those plans
23 will do in the future, so that's embedded in there. So
24 DSM is part of the study. In fact, the only thing
25 what's new is we postulated a winter demand-response

1 program. So I don't know how that's going to pan out;
2 that's something new. And that's in the plan. So we
3 have the energy efficiency, demand response, there's
4 purchases in the plan, there's a lot of solar in the
5 plan. I think this is pretty robust and covering a lot
6 of bases.

7 **Q** I understand that, and I know it may sound like I'm
8 asking the same question, but as far as what was
9 actually modeled in the spreadsheet, the various
10 different levels of resources that the spreadsheet was
11 choosing from, what I understand your response to say is
12 that you were looking at a CT or a CC.

13 **A** [LYNCH] Yeah, the spreadsheet calculates the revenue
14 requirements for a capital investment. The cost of the
15 energy efficiency programs, we haven't captured that in
16 our costs, because we're kind of thinking that is a sunk
17 cost and it's not incremental, or we wouldn't use that
18 to make a decision on what to do in the future. So the
19 Excel spreadsheet calculated the capital costs of
20 whatever plan we postulate. So Excel doesn't choose a
21 plan. The Excel model calculates these costs, puts them
22 together, so our engineers, our people, study this plan,
23 that plan, what if we moved it and did a lot of what-
24 ifs. But mostly, I mean, I think the heart of your
25 point is, are you really moving around just combustion

1 turbines and combined-cycles, and I'd say yes. The
2 other things were existing programs, except maybe for
3 this winter – except for the winter demand response;
4 that's something new. And I thought we took a risk
5 putting it in there, but it seemed like a good thing to
6 do. It's something I think the company really has to
7 look at. And then, of course, we have purchases in
8 there, too. Those aren't purchases that we've made, so
9 that's also postulate, should we make that purchase or
10 not. I don't know. We'll see when we get there. But
11 what it does is it pushes out, so the combined-cycle in
12 2034, we needed winter capacity before that. And we
13 think if we can make a 50-megawatt purchase for one
14 winter, well, that pushes out the plant a year. So we
15 were doing that to push it out a few years because it
16 seemed like the right thing to do. So, we don't have an
17 optimization model that you put in the basket and it
18 chooses all these options, because those things don't
19 work so well, anyway, I don't believe. That's another
20 story. It helps, but it doesn't make decisions for you.
21 But we tried a lot of things. Excel calculated the
22 capital costs, whenever we needed capital; PROSYM
23 calculated the production costs. And in the Excel
24 model, we were able to put it all together.

25 Q Okay, thank you. And if it goes forward with this CC,

1 the company would seek to recover the capital costs of
2 that, correct, through a CPCN proceeding?

3 A [LYNCH] I – presumably, there'd be a rate case where
4 you'd put the costs in rate base and adjust rates.
5 Presumably, that's the case, yeah.

6 Q And the company typically gets a return on equity when
7 building generation resources, like a CC?

8 A [LYNCH] Yes.

9 Q But it would not get a return on equity, if that
10 capacity were met by qualifying facilities, correct?

11 A [LYNCH] Any power purchases, the cost of that is passed
12 through, so all the solar QF payments go through the
13 fuel clause and there's no markup on that. It just
14 passes right through to the customers.

15 Q Okay. You discussed V.C. Summer in your testimony last
16 year, correct?

17 A [LYNCH] If you say so. Subject to check.

18 Q Subject to check, do you recall stating that, if the
19 nuclear units were delayed, the delay likely would only
20 be for a relatively short period?

21 A [LYNCH] Yes, that seemed true last year. That sounds
22 familiar to me.

23 Q And that these units were unavoidable capacity?

24 A [LYNCH] That's what I thought last year.

25 Q That resulted in lower capacity payments for qualifying

1 facilities, correct?

2 A [LYNCH] Yeah, the nuclear plants didn't seem to be
3 avoidable last year, and so avoided capacity cost
4 depends on capacity that can be avoided. So if you look
5 at our total need, less the capacity that cannot be
6 avoided, if we add the two nuclear plants in there, that
7 window of opportunity, that avoided capacity would be
8 smaller. So you're avoiding less capacity, less value.
9 So the avoided capacity cost last year would have been –
10 was lower because of that, yes.

11 Q Is it your position at the 540-megawatt CC is avoidable
12 at this point?

13 A [LYNCH] Oh, there's a need for capacity; it doesn't have
14 to be the combined-cycle.

15 Q So I know yesterday there was a lengthy discussion about
16 the waiver request. I'm not going to rehash that. So I
17 want to limit my questions to issues that pertain to
18 this proceeding, going forward. You said yesterday that
19 you did not include the PR-2 updated values in your
20 testimony filed on February 23rd, correct? The semi-
21 annual PR-2 update?

22 A [LYNCH] Oh, you mean – I don't believe we filed a PR-2
23 rate in the fall. Is that what you're asking? Yeah,
24 no.

25 Q Yes. But in response to a data request, the company did

1 provide our clients with an estimate of avoided energy
2 rates under the prior methodology, correct?

3 A [LYNCH] Yeah, I believe that's correct.

4 MS. OTTENWELLER: Okay. I'd like to enter that
5 discovery request into evidence at this time. And
6 I've premarked this as SACE-CCL Cross Exhibit 3.

7 [Document distributed]

8 CHAIRMAN WHITFIELD: We will enter that in as
9 Hearing Exhibit No. 10.

10 [WHEREUPON, Hearing Exhibit No. 10 was
11 marked and received in evidence.]

12 WITNESS LYNCH: And I should add to that,
13 those avoided energy costs, they came right out of
14 the JML-3 exhibit, where we studied the – we
15 studied the need to use a solar profile when we
16 calculated avoided cost? Well, in order to show
17 that, we also assumed the 100 megawatts round-the-
18 clock thing. You know, so it sort of tied in and
19 we had that data available.

20 BY MS. OTTENWELLER:

21 Q I'll give you a minute to look that over. Just tell me
22 when you're ready.

23 A [LYNCH] Okay, I think I'm ready.

24 Q Would you agree that the company's 2018 avoided energy
25 rates are lower than they would've been if the company

1 had used prior approved methodology, if we're comparing
2 what was filed in the PR-2 rate this year with the
3 numbers that you provided here?

4 A [LYNCH] No. My contention is we're using the same
5 methodology. It's difference in revenue requirements.
6 We use PROSYM to estimate production costs; that's
7 what's reflected in here. Base case, change case,
8 what's the difference in cost, and PROSYM gives us an
9 estimate of it. These are the numbers that result, this
10 year. Last year, they were different because it was a
11 different forecast, a different resource plan last year.

12 Q These numbers are different from the numbers that you
13 filed in PR-2, correct?

14 A [LYNCH] These numbers are different than what was filed
15 last year, yes. That's your question?

16 Q Do they appear to be higher?

17 A [LYNCH] I think they're lower, aren't they?

18 Q The numbers from last year?

19 A [LYNCH] These – aren't – these numbers are lower than
20 what was in the PR-2 rate last year?

21 Q Sorry. I'm asking if –

22 A [LYNCH] Maybe I don't understand the question.

23 Q – these numbers, which are an estimate of avoided energy
24 costs for PR-2 under the methodology that was provided
25 last year, I'm asking if these numbers appear to be

1 higher than the numbers that were filed in this year's
2 PR-2 docket.

3 A [LYNCH] Well, the PR-2 rate in this year is only for
4 solar, and we have three numbers in the five-year
5 tranches. Right? So —

6 Q Yes.

7 A [LYNCH] — you're asking are any of these numbers lower
8 or higher? Are some of them higher or lower?

9 Q I'm asking —

10 A [LYNCH] Or —

11 Q I know it's a little hard because you've changed the way
12 that the hours are structured where it's just one number
13 now instead of split up into various time periods. So,
14 I'm asking if you have a sense of whether the avoided
15 energy rates are higher or lower, this year, than if you
16 had used the prior approved methodology.

17 A [LYNCH] So I found the table — page 13 of my direct
18 testimony, I think, has the rates. I hope I'm doing
19 this right. So for a solar facility, 2018 to 2022, the
20 PR-2 rate is .02853. So, in terms of megawatt-hours,
21 that would be \$28.53 per megawatt-hour.

22 Q Does that appear to be lower than any of the numbers
23 you've included in this discovery response?

24 A [LYNCH] Yeah, it should be lower.

25 Q Thank you.

1 **A** [LYNCH] But that was part of the point of the study. I
2 mean, if you read that Exhibit -3, the whole point of it
3 was that, if we use the 100 megawatts' reduction in
4 every hour, we're going to overstate the avoided cost
5 associated with new solar, incremental solar, solar
6 beyond the 865 megawatts already there. When you add
7 that, more and more and more and more solar, the avoided
8 cost – the value – the benefit to the system from that
9 is going to decrease. That was the purpose of the
10 study. So these – on average, it's about \$4.85, I think
11 was my testimony.

12 **Q** So that dealt with avoided energy needs. Did the
13 company produce avoided capacity rates based on prior
14 approved methodology, to any party?

15 **A** [LYNCH] I have trouble – prior approved methodology.
16 We're always using difference in revenue requirements,
17 so it –

18 **Q** Sure, yes.

19 **A** [LYNCH] – has to be a change in the resource plan. Now
20 last year, I know Mr. Snowden asked me about this.
21 Hopefully, I explained it well. Last year – you know,
22 this all comes back, the halcyon days of yore comes to
23 my mind. Things were so simple. I mean, even though
24 there was a lot of controversy last year, you think
25 back, it was less complicated than it was now, because

1 back then we were planning only to a summer peak demand.
2 We only had to look at the summer peak. We had the 14
3 percent. Planning was so easy. And even our
4 spreadsheet, where we calculated the avoided capacity
5 cost, my guy, he set up that spreadsheet. In my mind –
6 I mean, I could describe it as simple, but I can also
7 describe it as very complex; there's a lot in it. But
8 he could automate the thing, to make it easy. So if you
9 put a 100-megawatt round-the-clock qualifying facility,
10 it would shift the plant. It would shift the revenue
11 requirements. So if a plant came on in 2030, for
12 example, and it had 50-60 years of revenue requirements,
13 this model would have that and calculate the present
14 worth of that. Then it shifts a year, 2031, all those
15 dollars move out. His spreadsheet automatically
16 calculates it. So now you have a difference in the
17 capital costs, revenue requirements. Very easy to do.
18 So we fooled around with that – I mean, we were asked
19 about it, but in my mind it didn't mean anything,
20 because, in the fall, I realized, I knew that our
21 planning process is going to get more complicated, that
22 we can't just look at the summer. Anybody who's just
23 looking at the summer, calculating anything, well, he
24 doesn't understand the problem the company has because
25 of this winter requirement. So when you calculate –

1 when someone says, "Well, can't you do it the way you
2 did it last year," I just – it's like a non sequitur. I
3 mean, I have trouble.

4 **Q** Okay. Maybe if I ask it this way: Using an 80/20
5 capacity-payment split, which is part of the
6 methodology, did the company produce that analysis of
7 avoided capacity rates for any party?

8 **A** [LYNCH] My contention is that the 80/20 split isn't
9 really how we calculate avoided cost. It's sort of a
10 pricing mechanism, if you see what I mean. It's how we
11 convey that avoided cost. So you look at what happened
12 to the power plants, the revenue requirements can shift
13 when you bring it all together, and you get, you know,
14 \$5 a kW-year, and then we're saying, "Well, let's split
15 that summer and winter," and I think that's more of a
16 pricing thing. But the \$5 is based on this methodology.
17 And to my knowledge, we have not provided an avoided
18 capacity cost based on all that stuff – boy, I hope to
19 heck we haven't. I would resist making that calculation
20 because it doesn't mean anything anymore. In my mind,
21 even if you make the calculation, it's just – it doesn't
22 mean anything. In my mind, it doesn't register. If
23 you're not looking at the summer and winter needs, if
24 you're not including the 865 megawatts of solar in the
25 expansion plan, you're not talking about anything

1 serious.

2 **Q** Well, one party – ORS – did ask for this information,
3 correct?

4 **A** [LYNCH] I don't know. Did we answer the question? I
5 hope not.

6 **Q** I believe that –

7 **A** [LYNCH] The avoided energy, we've already done, because
8 I had that study.

9 **Q** Sure.

10 **A** [LYNCH] We calculated the four periods with a 100-
11 megawatt drop, and that was all part of that – and I
12 thought that was necessary; we put a study in there that
13 said, "Well, if we did it that way, we would overpay.
14 Our customers would be overpaying solar for their
15 energy." So I think when you guys – that was what you
16 sent me. When you guys asked, "Well, what's the avoided
17 energy cost," well, that was easy to do. Just, well, a
18 little more calculations, but all the numbers – all the
19 numbers that went into that are right in my testimony.
20 I mean, there was tables and, you know, that we put
21 through, so you could use those numbers and calculate
22 these, so that was sort of a done deal on the energy.
23 But if somebody wanted to go back and calculate avoided
24 cost, it would – I mean, it wouldn't make sense. If you
25 want to – because then what you would have to do, if

1 you're going to do it – and this is just sort of – I'm
2 sorry to get winded, but the way I think about it, well,
3 if you're going to assume that all we need is to worry
4 about summer planning and all you need to worry about is
5 a 14 percent summer reserve margin, I'd say, "Well, why
6 stop there?" You're not going to worry about 865
7 megawatts of solar capacity. So let's assume all that
8 stuff away. And then my thinking is, well, hey, let's
9 assume the nuclear plants are back in there, let's
10 assume the load forecast was the same, let's assume we
11 were back there last year. Well, under all those
12 assumptions, you get the same number. Let's leave – so,
13 leave the PR-2 alone, you know, if that's how you're
14 going to operate. But, today, things are different. We
15 have to worry about the winter. We've got 865
16 megawatts. The nuclear plants aren't in the plan
17 anymore.

18 **Q** Let me ask you one more question on this. I know we've
19 been doing a lot of back-and-forth on it. Is it
20 possible for the company to calculate an updated
21 capacity cost that accounted for the change in nuclear
22 capacity, the 865 megawatts of solar, but still use an
23 80/20 capacity split?

24 **A** [LYNCH] I might have to ask you to ask the question
25 again, because the 80/20 capacity split does not come

1 into play when you're calculating the avoided cost.
2 It's a pricing.

3 **Q** Right, but in terms of calculating the payments,
4 capacity payments, for solar qualifying facilities.
5 Yesterday you agreed that the 80/20 split was a pricing
6 methodology, right?

7 **A** [LYNCH] That's how I think of it, yeah.

8 **Q** So, couldn't you calculate capacity payments for
9 qualifying facilities using the 80/20 split that you
10 used last year, but also accounting for changed
11 circumstances on V.C. Summer and solar additions?

12 **A** [LYNCH] Well, yeah – so let me try to work through this.
13 So our PR-2 rate today, what we want to do is just limit
14 it to solar. The avoided capacity cost from solar
15 beyond the 865 – the 865 helps us in the summer. The
16 next 100 megawatts of solar that comes on the system
17 might help in the summer, as well – probably will – but
18 does nothing for the winter. Therefore, since we don't
19 avoid any resources, the avoided capacity cost is zero.
20 So, in my mind, I'm thinking is she asking me to split
21 zero 80/20? You know what I mean?

22 **Q** So that methodology – that assumes changes to the
23 methodology of the winter reserve margin, correct? I'm
24 asking you, if you stuck with the methodology from the
25 prior docket but accounted for updated circumstances –

1 V.C. Summer, solar – but retained the prior methodology,
2 is it possible for the company to do that calculation?

3 A [LYNCH] Well, let me – what we could –

4 Q I mean, it appears you did it here for avoided energy,
5 in this exhibit I just introduced. I'm asking can you
6 do the same thing for capacity?

7 A [LYNCH] Yeah. Well, if we were required – and I hope
8 we're not. I don't want us to be. If we were required
9 to have a PR-2 rate for non-solar – so if you took a
10 resource, and depending – what's the avoided capacity
11 cost for a non-solar qualifying facility, for example,
12 well, you're going to have to specify what that resource
13 is. So let's suppose it's a dispatchable unit or maybe
14 something that's going to go around the clock. Right?
15 So it's going to help us in the winter, it's going to
16 avoid capacity. Well, a resource like that – which is
17 not solar – a resource like that would affect our
18 resource plan. If you affect the resource plan, if you
19 move capacity, shift it out a year or more, do something
20 like that, then there's a change in the capital cost,
21 and you end up with an avoided capacity cost and that
22 sort of thing. So we certainly can do that. I mean, if
23 we had to come up with a PR-2 rate for a non-solar
24 resource, if that was required, we could do it. But our
25 contention is we don't want to do it, we don't – there's

1 no need. There are no resources out there that are non-
2 solar that are looking for long-term contracts. And if
3 one or two showed up, I'd like to – let's handle them
4 one at a time and see if there's a – you know, if we
5 have a lot show up then maybe we'd need a rate. But we
6 went 35 years without a PR-2 rate, even for solar. For
7 nobody. And we were still ready to make a contract – if
8 someone shows up, we'd make a deal with them and
9 negotiate the contract and the terms and that sort of
10 thing. For 35 years, that worked, until there was an
11 explosion of solar facilities, and that's why we came up
12 with the PR-2 rate. So I'm saying it's really not
13 practical looking – so many solar facilities, all that
14 negotiating one by one doesn't make sense. We put out a
15 tariff, the PR-2 for the solar. And so we don't want to
16 do it for non-solar. But, certainly, if I didn't know
17 how to calcu- – if a non-solar facility came out and was
18 going to change our resource plan, I would be required
19 to figure out, well, what's the effect on the capital
20 cost and what's the number. I mean, we would have to
21 figure out how to calculate that.

22 MS. OTTENWELLER: Okay, thank you.

23 Mr. Chairman, at this time, I'd like to make a
24 request. The Commission's prior order on our
25 Motion to Compel found that there was no prejudice

1 to our clients because there was a sense that the
2 information we requested had been provided to the
3 parties through discovery. Company witnesses have
4 now clarified that they did, in fact, not provide
5 that information, despite requests from ORS, and
6 they've also asserted that these capacity
7 calculations can be made and are not too labor-
8 intensive. In light of that, I would request a
9 supplemental late-filed exhibit to clarify what
10 capacity costs would be under the prior approved
11 methodology including the 80/20 capacity split.

12 **CHAIRMAN WHITFIELD:** Mr. Gissendanner?

13 **MR. GISSENDANNER:** Mr. Chairman, the company's
14 response to the Coastal Conservation League and
15 SACE's Motion to Compel in this matter made very
16 clear that the company had provided to CCL and SACE
17 the four hourly – or the four avoided energy costs,
18 which was requested in the discovery. CCL and SACE
19 never requested any information regarding the
20 avoided capacity costs, which is why our response –
21 and I believe the Commission Order, as well, though
22 I don't have a copy of it in front of me – made
23 very clear that the company had provided the four
24 hourly avoided energy costs and other information
25 related to capacity.

1 CCL and SACE had ample opportunity to submit
2 discovery in this matter, if they wanted the
3 company to provide hourly avoided energy costs – I
4 mean, I'm sorry – avoided capacity – the avoided
5 capacity costs. However, as Dr. Lynch indicated,
6 the company had not calculated that number, and the
7 company would not be required to calculate that
8 number. This is simply an attempt by CCL and SACE
9 to conduct discovery after the time for seeking
10 discovery has already run.

11 CHAIRMAN WHITFIELD: Thank you.

12 MS. OTTENWELLER: If I may –

13 CHAIRMAN WHITFIELD: Ms. Ottenweller, yes.

14 MS. OTTENWELLER: – Mr. Chairman? By the time
15 the Commission had ruled on our motion, we were
16 within ten days of the hearing, so our clients
17 weren't able to – we were barred from making
18 further discovery requests, and I would also note
19 that ORS did ask the company to provide these
20 calculations and they were refused.

21 CHAIRMAN WHITFIELD: Hold on one second, Ms.
22 Ottenweller.

23 MR. GISSENDANNER: I'm –

24 CHAIRMAN WHITFIELD: Yes, sir.

25 MR. GISSENDANNER: I'm sorry. CCL and SACE

1 have submitted discovery within ten days but after
2 the ten-day period ran, which the company has
3 obviously – that was improper. CCL and SACE also
4 submitted discovery prior to the ten days and there
5 is no reason, given that they knew to ask – they
6 did ask for the avoided energy costs – for them not
7 to have asked for the avoided capacity costs, as
8 well. If they were going to ask for the avoided
9 energy cost, why were they not going to ask for the
10 avoided capacity cost? The fact that they failed
11 to do that, inadvertently or intentionally, is no
12 excuse for them to now be allowed to ask for that.

13 **CHAIRMAN WHITFIELD:** Let me hear from Mr.
14 Whitt and – Mr. Bateman, I believe I saw you
15 rising, too. But Mr. Whitt? And Mr. Bateman, if
16 you had a comment, after Mr. Whitt.

17 **MR. WHITT:** Mr. Chairman, thank you. This
18 Commission certainly doesn't want to put form over
19 substance and say that the way it was worded, it
20 shouldn't be given in a discovery request. We have
21 maintained at SBA that we did have a compressed
22 timeframe for discovery. It's 20 days for a
23 discovery request, is the minimum. Once you do one
24 in a 30-day period, you can't do a second request.
25 So this Commission has always been interested in

1 getting the full amount of information before it,
2 so, certainly, SBA would support the request from
3 Attorney Ottenweller that we receive this
4 information in the interest of full disclosure.
5 Thank you, Mr. Chairman.

6 **MR. GISSENDANNER:** Mr. Chairman, Mr. Whitt's
7 position appears to be that words have no meaning
8 and the company has to read discovery requests to
9 ask for things that they simply do not ask for.

10 **MR. WHITT:** Mr. Chairman, I do not make any
11 motion that words have no meaning. I don't know
12 where that came from.

13 **MR. GISSENDANNER:** That's what you just said.

14 **MR. WHITT:** I said this – you would be putting
15 form over substance if you try to say that
16 technicality is a reason that she can't have this
17 information. But I'm not going to have a back-and-
18 forth, and I know the Chairman doesn't want that.

19 **CHAIRMAN WHITFIELD:** No, we don't need that.

20 **MR. WHITT:** We support that request for the
21 reasons stated, Mr. Chairman.

22 **CHAIRMAN WHITFIELD:** Okay. And I do – since
23 ORS was pulled into this, I do want to hear what
24 Mr. Bateman has to say.

25 **MR. BATEMAN:** Mr. Chairman, I have relatively

1 brief remarks. We would reiterate the request that
2 Ms. Ottenweller made and express our support for
3 it. In addition, we could confirm that we did
4 request the avoided capacity piece, as Ms.
5 Ottenweller stated a second ago.

6 **MR. GISSENDANNER:** We provided responses to
7 ORS's request for discovery. And to the extent
8 that they have requested information that they feel
9 that we have not provided, their proper remedy is
10 for a motion to compel. They also – to the extent
11 that they are asking for a calculation of avoided
12 capacity, I think Witness Lynch has been very clear
13 that he has not calculated an avoided capacity
14 number based on using what the other parties are
15 terming the approved methodology from last year,
16 and if we did not perform that calculation there is
17 no requirement that we provide a calculation that
18 we've not performed. And we – yeah, and we have
19 given CCL everything that we've given to ORS.

20 **CHAIRMAN WHITFIELD:** Mr. Bateman, do you want
21 to respond to Mr. Gissendanner?

22 **MR. BATEMAN:** Again, a relatively brief
23 response. We believe the Commission should be
24 privy to all of the information that the Commission
25 needs to make the most informed decision, and we

1 believe that this is important to this aspect.
2 However, we defer to the Commission on whichever
3 decision it feels most prudent.

4 **CHAIRMAN WHITFIELD:** Give me just a moment.

5 [Brief pause]

6 Ms. Ottenweller, this has been a spirited
7 debate, but I am going to overrule your request.
8 The period – you had – there was opportunity for
9 this discovery and there were other proper
10 channels, and we do have timelines and deadlines
11 and guidelines here. I do think we need to stick
12 to that.

13 **MS. OTTENWELLER:** Thank you, Mr. Chairman.

14 **BY MS. OTTENWELLER:**

15 **Q** Dr. Lynch, I want to quickly move on to the discussion
16 of the 2017 reserve margin study. That study was based
17 on the component method, correct?

18 **A** [LYNCH] Yeah, to determine the reserve margin we looked
19 at the components of reserve and analyzed those. Yes.

20 **Q** Another possible approach would be the loss-of-load-
21 probability approach?

22 **A** [LYNCH] There's a problem with loss-of-load probability,
23 that approach, and it's easy to understand why it won't
24 work for SCE&G, really – and, in fact, I mentioned it
25 maybe as a support, too, in the PJM – after they hit the

1 2014 polar vortex, they found that their loss-of-load-
2 expectation methodology – they're questioning whether
3 that is adequate enough to handle the risk in the
4 winter.

5 Can I explain what's wrong with loss-of-load
6 probability? I can make this easy. This is probably a
7 good thing to do. So loss-of-load expectation or loss-
8 of-load probability – the terms are used interchangeably
9 – at the heart, two parts to it. I mean, basically,
10 there's two parts, and you get bells and whistles after
11 that, but two basic parts. First part is you calculate
12 an outage probability table. So you calculate this
13 outage probability table and then you apply it to the
14 loads. To get the outage probability table, it's really
15 an easy thing and all you're doing is combining the
16 forced outage rates of all the units. So every unit has
17 an effective forced outage rate. It's statistics.
18 There's this convolution theorem that tells you how to
19 put probability things together. So, put that aside. I
20 need to go to the whiteboard to show that, but it's
21 really a simple iterative – you add it all up. But
22 you've got this outage probability table, and then when
23 you apply the method you go to apply it to the loads.
24 Most people, traditionally, they go day by day. Go to
25 January 1st, what's the peak load on that day? Forty-

1 five hundred, whatever it is. You go to the outage
2 probability table and you figure out, what's the
3 probability that you won't have the supply to meet that
4 load? And you get an expected loss-of-load probability
5 and expected value. Maybe it would be .005 – I don't
6 know, whatever it is. Then they go to January 2nd,
7 what's the loss-of-load probability? January 3rd. You
8 add it all up. And, hopefully, for the year you get
9 0.1, so that would be a loss-of-load expectation of 0.1
10 days per year. In ten years, that would be one day in
11 ten years – ten times .01.

12 And so here's the problem – and this is what SCE&G
13 – we said, well, let's suppose that you have a – I mean,
14 we calculate loss-of-load probability and we got our
15 number, so here's the risk for the year. Then we say,
16 "Well, suppose we had a 500-megawatt surge on the load
17 in one of those winter days." So increase the peak 500
18 megawatts. And that's about – you know, the winter,
19 that's what the winter will do. My quadratic model, Mr.
20 Horii's linear model, but say about 500 megawatts, in
21 the neighborhood. So this is a reasonable question. So
22 ask the question, use loss-of-load probability, put this
23 500 megawatts in, what should our reserve margin be?
24 How many megawatts more do we need to get back to the
25 reliability we had? And so when you do that – and we

1 run through and calculate loss-of-load probability and
2 start adding supply, more and more supply makes us more
3 and more reliable. Add it all up. How much supply do
4 you have to get to get back to where you were? Turns
5 out you add 112 megawatts. So you put the 500-megawatt
6 peak increase in, and you find out, "Well, if I add 112
7 megawatts of supply, I'm back to the same reliability
8 based on loss-of-load expectation." And you think,
9 well, that doesn't make sense. On the face of it, I
10 contend that that's ridiculous. But why does it happen?
11 Because loss-of-load expectation is a summary for the
12 year. You put 112 megawatts into that loss-of-load
13 calculation. Every day, 365 days, every one of those
14 calculations is a little better, little more reliable.
15 Loss-of-load expectation goes down by a little bit, 112
16 megawatts' worth. Well, you add up that 112 megawatts,
17 I mean, you add that loss-of-load Delta, that small
18 decrease in loss-of-load expectation, and each of those
19 days you add it up and it counterbalances the increased
20 risk from that one day with the 500-megawatt spike.
21 Well, that doesn't make sense. This can't be. So loss-
22 of-load expectation, what it's doing is it's saying,
23 "Well, for the year, on average, a typical day or
24 something like that, that the system's reliable." Now,
25 we did the same thing, just to make the point – and this

1 is a little more dramatic – we used loss-of-load hours.
2 Some utilities, some people, use loss-of-load hours – I
3 guess they're thinking it's more reliable; it isn't.
4 But we did that, too. Suppose we had that spike some
5 winter morning, 500 megawatts – well, before we do –
6 loss-of-load hours, what do we get for the year, and I
7 guess hopefully you get 2.4 hours – right? – 2.4 hours
8 per year, ten years, that's 24 hours. You're back to one
9 day in ten, sort of. Sort of. It's not the same thing.
10 So we calculate loss-of-load hours and then we added the
11 spike, 500. Calculated it. Oh, now we're less risky,
12 got 2.4 hours or whatever it is. So the question is,
13 well, how many more megawatts do we have to add to get
14 back to where we were? Loss-of-load hours tells us 31
15 megawatts. So 31 megawatts' increase covers a 500-
16 megawatt spike in load? That's ridiculous. But why is
17 that happening? Why are you getting 31 megawatts?
18 Because now you have 8760 calculations. Just a little
19 bit more reliable. Loss-of-load expectation in each of
20 those hours is just a little bit less. But now there's
21 8760 days of calculations of hours of this little bit.
22 And it fully counterbalances in this methodology the
23 real increased risk of the 500-megawatt spike.

24 **CHAIRMAN WHITFIELD:** Dr. Lynch, the Commission
25 certainly appreciates your very thorough answer,

1 but Ms. Ottenweller is asking you very pointed
2 questions and, if you could, let's try to stick to
3 a very succinct reply to her.

4 WITNESS LYNCH: I apologize.

5 CHAIRMAN WHITFIELD: She's — she's gone a
6 little longer than we needed, and she needs to get
7 through her questioning. And we need a little more
8 succinct answers, and she's being very pointed in
9 her questions, so —

10 WITNESS LYNCH: I apologize.

11 CHAIRMAN WHITFIELD: — I'd appreciate it if
12 you would try to stay as pointed as she is.

13 WITNESS LYNCH: Yes, sir.

14 BY MS. OTTENWELLER:

15 Q Thank you, Dr. Lynch. Has the company previously used a
16 loss-of-load-probability approach?

17 A [LYNCH] We've made the calculation. We've never used it
18 to determine what the reserve margin should be.

19 Q Do you recall that in the 2013 IRP, this method was
20 described by the company as the traditional and
21 industry-standard technique?

22 A [LYNCH] We may have used those words.

23 MS. OTTENWELLER: I would ask the Commission
24 to take judicial notice of the company's IRP filed
25 in Docket 2013-2-E_[sic], including the company's

1 description of the loss-of-load-probability method
2 on page 28 of that IRP.

3 CHAIRMAN WHITFIELD: The Commission will take
4 judicial notice.

5 MS. OTTENWELLER: Thank you.

6 BY MS. OTTENWELLER:

7 Q Now, last year, Vice Chairman Randall asked you a
8 question about reserve margins. Do you happen to
9 remember that?

10 A [LYNCH] I don't. I'm sorry.

11 Q He asked whether a higher reserve margin raises rates
12 for customers. He pointed out that the old range was 12
13 to 18 percent and that, as of last year, it was 14 to 20
14 percent? Does that sound right?

15 A [LYNCH] That sounds right, yes.

16 Q And you stated that it would cost customers more to
17 increase the reserve margin. Do you agree with that?

18 A [LYNCH] Possibly it would, yes.

19 Q Now that the company is requesting a further increase to
20 21 percent, do you agree that will further increase
21 costs for customers?

22 A [LYNCH] It should, yes.

23 Q Thank you.

24 A [LYNCH] Hopefully, we're able to lower those costs by
25 demand-response programs – would be cheaper than

1 building a power plant. But there'd be – there's a cost
2 to it, yes.

3 Q I want to turn, now, to the company's implementation of
4 the net-metering methodology. In your testimony, you
5 provide the company's 2018 update to the value of
6 distributed generation in the net-metering methodology,
7 correct? The table with the 11 components?

8 A [LYNCH] Yes, that's correct.

9 Q Last year, SCE&G – or, this year, SCE&G has included
10 non-zero values for avoided energy, avoided criteria
11 pollutants, and line losses, correct?

12 A [LYNCH] Yes, and then – but there was also an update for
13 that line ten, with the environmental cost? Didn't we
14 have something there?

15 Q Sure.

16 A [LYNCH] But, yes.

17 Q You also break out some avoided energy costs from the
18 avoided energy component.

19 A [LYNCH] I'm sorry, that was really fast.

20 Q You also break out some avoided environmental costs from
21 the avoided energy component?

22 A [LYNCH] Yes, that's correct. Yes.

23 Q And you've included zero values for all the other
24 categories?

25 A [LYNCH] Many of those, yes.

1 Q That includes avoided capacity, ancillary services,
2 transmission and distribution capacity, avoided CO₂, fuel
3 hedge, utility integration, and interconnection costs,
4 and administration costs?

5 A [LYNCH] That's correct.

6 Q With the exception of eliminating the avoided capacity
7 values and separating out some of the avoided
8 environmental costs, those zero values are for the same
9 exact categories as last year's update; is that right?

10 A [LYNCH] Pretty close, yeah.

11 Q And the same is also true for 2016?

12 A [LYNCH] Yes.

13 Q The same is also true for 2015? To the best of your
14 memory?

15 A [LYNCH] I guess, yeah.

16 Q Okay, thank you. I have one quick follow-up question on
17 variable integration charges. You were talking with Mr.
18 Snowden about that yesterday.

19 A [LYNCH] Yes, ma'am.

20 Q Are variable integration charges factored into the
21 PROSYM model used to calculate the PR-2 rate that's
22 currently in effect?

23 A [LYNCH] I can't say they're factored in, so, but PROSYM
24 has to dispatch the facilities to – well, to the load.
25 And then, so, you have the base case and the change

1 case, and you take what's the change in the dispatch
2 cost, and whatever comes out – if you had – if the
3 change is based on the solar profile, the avoided cost
4 is lower. I'm assuming that just means that you have
5 less value, you can't save as much energy in the
6 production of energy to follow the load, because it's
7 more difficult. If you put more solar on, it's more
8 difficult so it's less value.

9 **Q** And aside from just running the PROSYM model with more
10 solar in it, there's no change to how variable
11 integration charges are being considered by PROSYM?

12 **A** [LYNCH] Yeah, there's nothing – there are no – there's
13 no quantity value of variable integration charges that
14 we put into the model. So that's – what we do is
15 dispatch – PROSYM just dispatches the units, based on,
16 you know, the capacity of the unit, the cost of the
17 unit, heat rate, that sort of thing. But there's
18 no place where we dial in, here's the variable
19 integration cost.

20 **Q** So there's no – that means there's no change from this
21 year, from last year?

22 **A** [LYNCH] We're using the same PROSYM, yeah, so that's the
23 same.

24 **Q** Okay. Just a couple more questions. Several times,
25 you've talked about this 17 percent number when you

1 discussed solar generation on SCE&G's system. Does that
2 sound right? A couple of times yesterday?

3 A [LYNCH] It doesn't sound – I don't –

4 Q Okay. So when you – maybe I should ask it this way:
5 When you talk about the increase in solar generation
6 that you are anticipating on SCE&G's system, what is the
7 percentage that you use?

8 A [LYNCH] Oh, yeah. Let me – [indicating].

9 Q Maybe if I ask you a couple of other questions, we can
10 figure it out together. I don't want you to have to get
11 out your calculator right now.

12 A [LYNCH] I think that was the ratio, 17 percent, and
13 actually someone else had – but that's the ratio of – I
14 believe that's the ratio of the 865 megawatts divided by
15 our gross peak, you get about 17 percent. So I think
16 that's where – so the 865 by itself, when you compare
17 865 to California, for example, or maybe even to North
18 Carolina, it doesn't sound like much, but when you put
19 it on SCE&G's system, it's a large percentage, and that
20 was sort of the point of the 17 percent.

21 Q All right. So the way I got 17 percent, when I was
22 doing this math last night, is by dividing this year's
23 summer peak in 2018 by the nameplate quantity of solar
24 projected to be on-line three years from now, in 2021.
25 Does that sound right to you? So looking at that 865,

1 which is not supposed to go on the system until 2021,
2 and then dividing that by the 2018 summer peak, gets to
3 17 percent.

4 **A** [LYNCH] Yeah, I, as a ballpark, I took 5077 megawatts –

5 **Q** Yeah.

6 **A** – as the peak and divided 865 by that, and I got 17
7 percent.

8 **Q** Okay. So and that is – the 577 is the gross territorial
9 peak for 2018?

10 **A** [LYNCH] That's correct.

11 **Q** And you're comparing that to the amount of solar that is
12 expected to be on the system in 2021?

13 **A** [LYNCH] Just to sort of normalize it, in some fashion,
14 yes.

15 **Q** And that's based on solar's nameplate capacity, right?

16 **A** [LYNCH] AC nameplate. The 865, I believe, is AC
17 nameplate.

18 **Q** Okay. I want to talk about firm capacity for a minute.
19 This spreadsheet states that there will be 58 megawatts
20 of solar firm capacity – that there are 58 megawatts of
21 firm capacity currently on the system, right? That's
22 line five for 2018?

23 **A** [LYNCH] Yes.

24 **Q** Subject to check, would you agree that comes out to
25 about 1 percent of the system's firm capacity today?

1 A [LYNCH] Yes, yeah.

2 Q So once the 37-megawatt solar plant comes on-line later
3 this year – that's line seven – that would increase to
4 1.7 percent, subject to check? Does that sound right to
5 you?

6 A [LYNCH] You are taking the –

7 Q I'm adding that to the 37-megawatt solar plant in line
8 seven.

9 A [LYNCH] Adding to the 58?

10 Q Yeah.

11 A [LYNCH] So you're not using nameplate, you're using –

12 Q I'm looking at firm capacity.

13 A [LYNCH] The firm credit that we're giving to it, the 35
14 percent? Yes, you would get 35 percent of whatever the
15 nameplate ratio is. Yeah.

16 Q Yes, sir. So looking out over the 15-year plan, the
17 company anticipates adding another 244 megawatts of firm
18 solar capacity, correct? That's the 875 megawatts at 35
19 percent?

20 A [LYNCH] Right. Yeah, the nameplate is 875 megawatts,
21 and then on the summer peak we would give – we were
22 saying about 35 percent of that, we can call firm or
23 like a capacity type value. Yes.

24 Q So subject to check, over the 15-year plan, solar would
25 make up only about 4.8 percent of the total system firm

1 capacity? Does that sound right to you?

2 A [LYNCH] Uh –

3 Q I can tell you how I got that, if that would –

4 A [LYNCH] Subject to check. So what you're taking is –

5 Q I'm taking 302 megawatts of –

6 A [LYNCH] Nameplate capacity times 35 percent.

7 Q Out of the –

8 A [LYNCH] And then divide that by the summer capacity.

9 Q So 6252 megawatts, total.

10 A [LYNCH] You got 4 percent? If you did it for the
11 winter, of course, you'd get zero, but – but yes. Your
12 arithmetic may be good. Subject to check.

13 Q Subject to check, 4.8 percent of firm system –

14 A [LYNCH] Yes.

15 Q – capacity is solar.

16 MS. OTTENWELLER: Thank you. No further
17 questions.

18 CHAIRMAN WHITFIELD: Thank you, Ms.
19 Ottenweller.

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1 **CHAIRMAN WHITFIELD:** One second, Mr. Bateman.

2 [Brief pause]

3 Mr. Bateman, Ms. Pittman, ORS questions for
4 this panel?

5 **MR. BATEMAN:** ORS has no cross-examination for
6 this panel. Thank you.

7 **CHAIRMAN WHITFIELD:** Okay. Commissioners,
8 questions for this – for the company's panel.
9 Commissioner Elam.

10 **EXAMINATION**

11 **BY COMMISSIONER ELAM:**

12 **Q** Good morning.

13 **A** [PANEL] Good morning.

14 **Q** Mr. Raftery.

15 **A** [RAFTERY] Yes.

16 **Q** I haven't heard your voice this morning.

17 **A** [RAFTERY] It's good to see you.

18 **Q** Your prefiled direct testimony states that SCE&G has
19 achieved the 1 percent goal for the utility-scale
20 facilities and the 1 percent goal for customer-scale
21 facilities set forth in Act 236. Correct?

22 **A** [RAFTERY] Yes.

23 **Q** How close is the company to meeting the 2 percent net
24 energy metering limit or cap under Act 236?

25 **A** [RAFTERY] We're about two-thirds of the way through.

1 According to my estimates, we'll reach the 2 percent cap
2 next May, so after next year's fuel hearing we will –

3 Q May 2019?

4 A [RAFTERY] Yes.

5 Q You state on page nine of your testimony that non-
6 residential customers holding Bill Credit Agreement
7 approvals must be interconnected by April 27th of this
8 year, correct?

9 A [RAFTERY] Correct, with the exception of the extensions
10 that the Commission granted earlier this year.

11 Q Okay. Do you expect that all of those 39 systems will
12 be interconnected by that date?

13 A [RAFTERY] I don't have any indication that any of those
14 projects will fall out, but some may.

15 Q Mr. Rooks.

16 A [R00KS] Yes, sir.

17 Q On your Exhibit AWR-1 – and I'll give you a second to
18 get there; it's down at line 28 – the company included
19 carrying costs and undercollected balances in the month
20 of December 2017 and January 2018, in accordance with
21 Commission Order No. 2017-246. Why were no carrying
22 costs included to the benefit of ratepayers in the
23 months that resulted in overcollection balances?

24 A [R00KS] Because the company, in last year's proceeding,
25 was actually agreeing not to recover all of its costs.

1 And so, to the extent that there were any
2 undercollections, we had requested carrying costs on
3 those balances, but for any overcollections there
4 would've been none.

5 Q Okay. You had enough of a break now, Dr. Lynch?

6 A [LYNCH] Yes, sir.

7 Q On Table 10, on page 27 of your direct testimony, it
8 shows avoided energy costs decreased from 3.074 cents
9 per kilowatt-hour, in the current period, to 3.014 cents
10 per kilowatt-hour in the IRP 15-year planning horizon,
11 correct?

12 A [LYNCH] I'm sorry, what number – what row is that?

13 Q Table – well, let me get there.

14 A [LYNCH] Table 10?

15 Q Yeah, Table 10 on page 27.

16 A [LYNCH] And it decreased.

17 Q Right.

18 A [LYNCH] Yes.

19 Q Okay. The base fuel component in the test year didn't
20 change from the previous year, correct?

21 A [LYNCH] Maybe not. I don't – I don't know.

22 Q Assuming that –

23 A [LYNCH] Yeah.

24 Q – why does the base fuel factor remain constant at 2.451
25 cents per kilowatt-hour while the avoided energy costs

1 decline?

2 **A** [LYNCH] Well, the fuel factor isn't part of these
3 calculations. These are, you know, sort of forward-
4 looking and it's based on estimated production cost when
5 we dispatch the system, and then the time periods and so
6 forth. So the fuel factor would be – I'm thinking
7 that's a different calculation, a different –

8 **Q** Wouldn't have any impact?

9 **A** [LYNCH] No, it has no impact on that. We use PROSYM, I
10 think, to help the Rate Department and Mr. Rooks decide
11 what that factor should be.

12 **Q** Okay.

13 **A** [LYNCH] But it doesn't affect this table, no.

14 **Q** All right.

15 **A** [ROOKS] The base fuel cost is essentially a weighted
16 average of the full system of resources and purchases.

17 **Q** Okay.

18 **A** [LYNCH] Thank you.

19 **A** [ROOKS] So avoided cost is more of an incremental type
20 analysis.

21 **Q** All right. Dr. Lynch – you may have said this at some
22 point – tell me how the change in the reserve margin
23 went from 14 percent to 21. What drove that change? I
24 mean, was it some data change as to weather or was it
25 just the methodology's change?

1 **A** [LYNCH] Well, I mean, for the past several years we've
2 been worrying about it, obviously, and we're just
3 getting around to – at least my department's sort the
4 ones that would have to do the calculation. It was just
5 last year we were getting around to it. But what's
6 driving it, I mean, one of the big impetuses is the
7 addition of solar. The more solar on the system, the
8 lower the summer demands are going to be, and the more
9 you have to worry about the winter. That just makes
10 sense. The other thing going on, I mentioned yesterday,
11 too, was that residential customers tend to be winter
12 peaking and, you know, they put more of a load in winter
13 than summer, even under normal weather conditions.

14 **Q** Has that changed over the last few years or has –

15 **A** [LYNCH] No.

16 **Q** – it always been that way?

17 **A** [LYNCH] If you look over the past several years, any
18 year where we peaked in the winter – I think it was five
19 out of ten years, or something like that – if you
20 compared summer to winter, residential, commercial,
21 their contributions, commercial/industrial, depending on
22 the weather, they might go up a lot, but it's really the
23 residential that spikes up in the winter, and that's
24 what's causing – whenever we peak in winter, it's really
25 the residential class that's making a significant

1 difference from what they were contributing in the
2 summer.

3 Q Spikes up from what?

4 A [LYNCH] From what they contributed in the summer. So,
5 for example, if we're going to peak in the winter, so
6 you'd be comparing maybe the January winter peak to the
7 summer — prior summer — August peak, whatever, you know.
8 And you look at the contributions to that peak by class
9 and say, "Well, why are we peaking in the winter?
10 What's making us peak in the winter?" And the answer is
11 going to be obvious if you look at that load research
12 data; it's going to be obvious that it's the residential
13 class whose load has increased maybe to 500 megawatts or
14 a little more.

15 Q Could that have something to do with, perhaps, having a
16 milder-than-normal summer?

17 A [LYNCH] Except that it happens consistently, so I'd say
18 no. Of course, if you have — let me answer the question
19 even better than that, because that factor's what that
20 differential is going to be. But when we make our
21 forecast, we're forecasting based on normal weather and
22 I'm looking at the contribution per customer, for the
23 residential customer. So I have — I get an estimate,
24 what does he normally do in the summer, what does he
25 normally do in the winter? And in the winter, it's

1 almost 1/2 kW, 4/10 of a kW, something like that. So
2 under normal weather conditions, summer and winter
3 normal, the residential customer will put in about 4/10
4 of a kW more on the winter than the summer. About .4,
5 in that neighborhood. Of course, .4 kW is not much, but
6 you multiply it by 650,000 customers, and then we put
7 the weather effect in that .4 kW – you know, depending
8 on what the weather does.

9 **Q** Does having a weather normalization adjustment or not
10 having one drive this at all? Is it just customer usage
11 or is it revenue recovery?

12 **A** [LYNCH] This is just customer usage, what do customers –
13 for forecasting, when you forecast you want to take the
14 weather – I mean, a lot of variation due to weather, you
15 want to take that out in your planning to see what the
16 underlying trend is. And so that's what we're doing
17 when I was talking about kW per customer; we look at the
18 history, which is affected by weather, certainly, and
19 then we try to weather-normalize it through statistical
20 things and figure out, "Well, what is the average?" "If
21 we have normal weather next year, what is our
22 residential customer going to contribute to the winter
23 peak? To the summer peak?" And it's higher in the
24 winter.

25 **Q** Now, you said you got around to analyzing this. It has

1 not been done before? Or when was the last time you
2 looked at the reserve margin to decide whether it needed
3 to change?

4 A [LYNCH] Well, we've always worried about – I mean, our
5 concern – and the planning, everything has been based on
6 the summer. And I'm thinking it's after, probably, the
7 polar vortex where the issue really sort of came to
8 light that things were changing.

9 Q You said five out of ten years. Are those – is it the
10 most recent five years or is it just something that
11 fluctuates a little bit from year to year?

12 A [LYNCH] Well, it's three out of the last five years, you
13 know, so even this year, this winter, our peak was
14 higher than what we had in the summer. Weather plays
15 into that, you know, so –

16 Q What is the – if you look back at this over the years,
17 what is the typical spread between the winter peak and
18 the summer peak? I mean, if you're talking about 14 to
19 21 –

20 A [LYNCH] Yeah.

21 Q – it's seven points. What's – in those five of those
22 ten years, what's the difference?

23 A [LYNCH] I can go back and calculate that, but maybe a
24 quicker answer would be if you look at the forecast and
25 look at the firm demand instead of the gross peak, you

1 don't look at – you look at the net firm demand, we're
2 forecasting 4803 for the summer, 4802 for the winter.
3 So weather-normalized, doing the best figuring what's
4 going to happen, they're identical.

5 Q Yeah.

6 A [LYNCH] Now, you go back in history, I mean, you get a
7 different number, for sure, depending on how the weather
8 plays out and how you do it, and, of course, the history
9 is the history, too. There's less solar behind the
10 meter, so the summers might be a little bit higher
11 there. Does that help?

12 Q Is this, in a way, almost like long-term weather
13 forecasting? Are you anticipating colder winters, or is
14 it just these past couple of years that you're really
15 kind of flipping where you're emphasizing the peak need?

16 A [LYNCH] No, what I – what I really think is happening –
17 and this is – I'm just looking at stuff and sort of
18 guessing. Because when we forecast, I mean, there's no
19 guessing, but we look at the data and, you know, and
20 then get the result. So when it comes to the forecast,
21 I believe that, with all my heart, it's very reasonable
22 because of all the details. But stepping back, looking
23 at trends, it's been my impression that, since right
24 before the Great Recession, with the housing bubble, on
25 our system the summer peaks have seemed to level off.

1 If you ever look at a graph – and it's not only our
2 company; every utility – seems like every utility I've
3 looked at. So we have growth – and even I brought this
4 to the management of the company. Heck, the company's
5 probably grown for 15 years, every year, grown, grown,
6 grown, until you get to 2007, and then it's leveled off.
7 Since then, it's been sort of flat. And my contention
8 is that this is – a lot of it has to do with
9 conservation. Since that recession, the economy hasn't
10 been so hot; I think people are trying to conserve, they
11 play with the thermostat. And so the summer peaks, I
12 think, have sort of leveled off, and I think they're
13 going to start growing again. But in the winter peak,
14 because of these heat strips, you get a cold morning,
15 you're going to get that spike, no matter what you do to
16 the thermostat. The heat pump is going to kick on to
17 supplemental heating, the load goes up, so you don't see
18 that same effect in the winter. So, that, I believe is
19 part of what's going on, plus you throw in the solar
20 where you've got 40, 50, whatever it is, behind the
21 meter, that's going to affect the summer calculation of
22 impact, and then it won't affect the winter. I think
23 those are trends that are going on.

24 **Q** Do demand-side programs figure into that? Your
25 calculation of operating margin – reserve margin?

1 **A** [LYNCH] Yeah. Right now, we assume whatever the – and
2 mostly energy efficiency, but we have demand response,
3 as well. But the energy efficiency, we're figuring
4 it'll affect the winter peak the same as the summer, but
5 we're trying to get better estimates.

6 **Q** Okay.

7 **A** [LYNCH] Can I add something?

8 **Q** Go ahead.

9 **A** [LYNCH] Thank you. The other issue is not only the
10 level of summer and winter peak; it's that risk. So,
11 without a doubt, the winter peak I know can increase –
12 shoot up by 500 megawatts; summers, somewhere around 200
13 megawatts. So you have that in some of the planning and
14 reserves and so forth that are driven by that risk, you
15 know, as well as the level.

16 **Q** Okay. Would we expect, with the abandonment of the two
17 Summer reactors, SCE&G's avoided capacity costs to go
18 up?

19 **A** [LYNCH] I think that was the general expectation.

20 **Q** Right. Looking at the most recent DER report, SCE&G's
21 costs seem to be well below those of Duke Energy
22 Progress, Duke Energy Carolinas. Would you expect the
23 avoided cost number to be more in line with those two
24 other utilities?

25 **A** [LYNCH] The avoided cost calculations that I do has

1 nothing to do with –

2 Q The avoided capacity.

3 A [LYNCH] Avoided capacity?

4 Q Project cost, I'm sorry.

5 A [LYNCH] Yeah, well that – I don't look at DER costs. I
6 don't understand them, so it has nothing to do with my
7 calculations.

8 Q Well, you look at avoided capacity.

9 A [LYNCH] Yeah, but I look at the avoided capacity costs.
10 My reasoning is, when I look at the expansion plan, if I
11 want to calculate avoided capacity cost I'd say, "Well,
12 if you had another 100 megawatts of solar on top of the
13 8065, what's it going to do to the plan? Is it going to
14 eliminate any power plants, or shift them, or move
15 them?" And if it doesn't, the avoided cost has to be
16 zero. Now, I think, with Duke Power – maybe I shouldn't
17 say that, but I thought Duke Power, they're using the
18 peaker method and that's administratively determined in
19 North Carolina?

20 Q I'm just talking about the avoided capacity now.

21 A [LYNCH] Yeah, so that's the avoided capacity. So I
22 think they use a proxy methodology that's required in
23 North Carolina. Maybe I'm wrong, or maybe that's
24 changed. So I'm not sure that reflects –

25 Q Okay.

1 **A** [LYNCH] – the actual cost.

2 **COMMISSIONER ELAM:** Okay, thank you.

3 That's all I have, Mr. Chairman.

4 **CHAIRMAN WHITFIELD:** Commissioner Bockman.

5 **COMMISSIONER BOCKMAN:** Thank you, Mr.
6 Chairman.

7 **EXAMINATION**

8 **BY COMMISSIONER BOCKMAN:**

9 **Q** Good morning, gentlemen.

10 **A** [PANEL] Good morning.

11 **Q** Dr. Lynch, those halcyon days of yore that you spoke
12 about in your response to Ms. Ottenweller, as I get
13 older those days don't seem quite as simple as we
14 thought at the time. Would you agree with that?

15 **A** [LYNCH] I think I'd go the other way. Thinking back,
16 last year might've been better than this year, because
17 of what we're going through. But maybe – maybe, yeah.

18 **Q** Well, let's don't look backwards, let's you and I look
19 forward for just a minute.

20 **A** [LYNCH] Yes, sir.

21 **Q** Do you have a copy of the 2018 IRP with you? I think
22 it's Hearing Exhibit No. 9.

23 **A** [LYNCH] I know I have some of the pages. Was that
24 handed out to me yesterday?

25 **Q** I'm not sure the whole – the entire one was. It may

1 have been.

2 A [LYNCH] But I have some pages.

3 Q All right. Well, do you have page 42 with that?

4 A [LYNCH] Oh, yes. Yeah.

5 Q There's a table on that page, is there not?

6 A [LYNCH] Yes, sir.

7 Q As I read that table, it would show that in the years
8 from 2020 to 2032, that the forecasted summer peaks are
9 higher than the winter peaks during all those years. Is
10 that —

11 A [LYNCH] That's correct, yes.

12 Q And in the winter you have no solar available. This
13 table shows that; is that correct?

14 A [LYNCH] That's correct, yes.

15 Q What's the reason for that?

16 A [LYNCH] That's an assumption that we make. Like I
17 mentioned that 2007, or so, things looked like the
18 economy flattened out, and I'm thinking it's
19 conservation? Trying to understand the numbers, but I
20 don't have proof that this is the case. So what I'm
21 thinking is customers are turning back the thermostat.
22 When the economy comes back, household income and median
23 household income, that sort of thing, we're figuring
24 maybe the customers will go back to pre-recession usage.
25 So, prior to the recession, residential customers in the

1 summer – I don't remember the numbers.

2 Q Well, I'm not really asking about – what I'm asking is,
3 what's the basis for which you indicate that no solar
4 would be available?

5 A [LYNCH] Well, in the winter.

6 Q In the winter.

7 A [LYNCH] In the winter, it won't affect – it doesn't
8 affect the peaks, and largely because what we looked at
9 – and that was one of my studies – is that, in the
10 winter, the company seems to peak before solar starts
11 generating or after it stops. So it doesn't – the solar
12 is not going to contribute.

13 Q So it's not available, is that what you – it's not
14 available –

15 A [LYNCH] Yeah.

16 Q – to meet –

17 A [LYNCH] I don't know if "available" is the right word,
18 but it's not generating any capac- – any energy.

19 Q Okay. All right. And what effect does that have on
20 your reserve margin, the unavailability or – I'm sorry,
21 that term that I used.

22 A [LYNCH] Well, in the winter, you need whatever capacity
23 you need, and solar doesn't help you. In the summer,
24 it's there for some hours and helps, to the tune of this
25 35 percent ratio.

1 Q All right. If you were to need that capacity or that
2 availability in the winter, how would you go about
3 providing that?

4 A [LYNCH] Well –

5 Q The 300 megawatts that you show is zero between summer
6 and winter, for the period 2020 through 2032, suppose
7 you needed that, how would you go about providing it?

8 A [LYNCH] Well, in the resource plan, we do provide it.
9 So we'd add the combined-cycle units; the other capacity
10 that we're adding there is capacity that would be there
11 year-round. It would be there in the summer. Some of
12 the purchases that we make in the IRP that we haven't
13 made yet, but you notice they were all in the winter.
14 And then the other thing is embedded in this, too, is
15 100 megawatts related to demand response. The thinking
16 here is that winter is a peaking type thing; we want to
17 clip those peaks. And it would be cheaper to have this
18 demand-response resource in the winter than to build a
19 power plant. So embedded in here is all the capacity.
20 And maybe what happens – maybe this is the question, too
21 – you get that 300 megawatts' credit in the summer, and
22 what that means then is, "Well, you know, there's 300
23 megawatts you don't need to add in the summer," but you
24 have to add it in the winter if the load is that high.

25 Q All right. Mr. Raftery, in his testimony – well, let me

1 ask him just a minute, and I'll come back.

2 Mr. Raftery.

3 A [RAFTERY] Good morning.

4 Q Raftery, I'm sorry. Mr. Raftery, in your testimony, you
5 talk about you envision a microgrid that uses energy
6 storage. When you say "envision" – you know, I
7 sometimes envision myself as, you know, Chief Justice of
8 the Supreme Court. There is no probability of that.

9 [Laughter]

10 What's the probability – what's the probability in
11 your vision that the company would actually provide a
12 microgrid with some kind of storage?

13 A [RAFTERY] I think it's unfortunate that you might not
14 become Chief Justice.

15 Q Thank you, very much. I appreciate that. I don't know
16 if you've got a vote, but I'll take it.

17 [Laughter]

18 A [RAFTERY] But I do feel confident in our ability to
19 procure the necessary components to establish a
20 microgrid facility at the Lake Murray Research Center.
21 We've talked a bit over the last two days about solar
22 and storage, and we've kind of hinted a bit at what
23 storage could provide our grid and our system in taking
24 some of that excess solar, during the day – whether it's
25 in the summer or the winter – and dispatching it where

1 we have the peaks. When you combine that sort of
2 concept with a set of interconnected loads, such that
3 they could automatically, seamlessly disconnect or
4 connect to the grid, I think that's a very likely
5 possibility.

6 **Q** In that vision that you have or in that plan that you
7 have, what size facility would you be talking about?

8 **A** [RAFTERY] Initially, I think we would look for a 500
9 kilowatt, maybe a 600-kilowatt solar array on the top of
10 an existing capped coal-ash landfill, and then at the
11 base likely we would place a 500-kW lithium ion battery.
12 So the total nameplate capacity would be about a
13 megawatt, maybe 1.1 megawatts.

14 **Q** Pretty small. Dr. Lynch, would that have any effect on
15 the company's avoided capacity cost calculation,
16 something of that size?

17 **A** [LYNCH] The small grid? No.

18 **Q** Dr. Lynch, let me ask you a hypothetical question:
19 Suppose you were in the business – in the solar
20 generation business. What would your position be on the
21 company's proposal of zero avoided capacity cost? Would
22 your position be the same as the Solar Business Alliance
23 here?

24 **A** [LYNCH] I suspect I'd say that not only is the capacity
25 too low, the energy is too low, as well.

1 Q And why would you say that?

2 A [LYNCH] Oh, because you're looking at your business,
3 instead of at the company's avoided cost.

4 COMMISSIONER BOCKMAN: Okay. Thank you, Dr.
5 Lynch. Thank you, gentlemen.

6 CHAIRMAN WHITFIELD: Thank you, Commissioner
7 Bockman.

8 At this time, we're going to take about a
9 five-minute break, and we'll resume with
10 Commissioner questions of the panel. And we're
11 going to try to push on and continue on today. I
12 will remind you, we do have a Commission Meeting at
13 2, so I don't know how long we'll go, but it's the
14 goal of this Commission to keep pushing on. So,
15 for right now, we're going to take about five
16 minutes.

17 [WHEREUPON, a recess was taken from 11:40
18 to 11:54 a.m.]

19 CHAIRMAN WHITFIELD: Please be seated. I'll
20 call this hearing back to order, with the panel
21 still under oath. I believe we finished with
22 Commissioner Bockman's questions. We've got a few
23 more Commissioner questions. At this time, I'm
24 going to go to Commissioner Randall.

25 VICE CHAIRMAN RANDALL: Thank you, Mr.

1 Chairman. I spent about five minutes just
2 envisioning Commissioner Bockman as the Chief
3 Justice of the Supreme Court. He can look right
4 cool.

5 [Laughter]

6 COMMISSIONER BOCKMAN: I'd like to have more
7 people with that vision.

8 [Laughter]

9 VICE CHAIRMAN RANDALL: I was also kind of
10 amazed, after Ms. Ottenweller called up my
11 question, I actually remembered that question. So
12 that was a pretty amazing thing, in its own right.

13 EXAMINATION

14 BY VICE CHAIRMAN RANDALL:

15 Q Mr. Rooks, no questions. Okay. Mr. Raftery, just one
16 quick question. Page 11 and 12 of your prefiled, you're
17 talking about the company's Community Solar Program and
18 that the remaining capacity's reserved for low-income.
19 When do you think that's going to be – how long do you
20 think that's going to be before that really takes – is
21 full?

22 A [RAFTERY] Yeah, right now we have subscribed 670
23 kilowatts of a 1-megawatt carve-out for low-income.
24 Those subscriptions probably started in earnest late
25 fall or early winter of last year. I think it will be

1 fully subscribed within a few months.

2 **Q** Okay, thank you.

3 Dr. Lynch, just quickly. When I was talking with
4 Ms. Glick yesterday, we were – it seems like, when we
5 were talking capacity factor or capacity ratio, we were
6 having a difference of definitions, and I just wanted to
7 clear that up, if you could.

8 **A** [LYNCH] Okay. Would it help looking at the resource
9 plan? My attachment JML-1? Maybe this would help?

10 **CHAIRMAN WHITFIELD:** The briefest definition
11 you've got.

12 **BY VICE CHAIRMAN RANDALL:**

13 **Q** Yeah.

14 **A** [LYNCH] Okay.

15 **Q** They told me to be brief. I'm never brief.

16 **A** [LYNCH] Well, so, the capacity ratio and how much
17 credit, capacity credit, is used from the nameplate, so
18 that's the 35 percent capacity ratio that we're using.
19 A capacity factor is a well-defined term in the
20 industry, and it is the ratio of how much energy a
21 resource actually produces to how much it can produce if
22 it ran every hour at full capacity. So I would suggest
23 not using "capacity factor" the way she's using it.

24 **VICE CHAIRMAN RANDALL:** I understand. That's
25 why I had not heard "capacity factor" used in that

1 form. So, thank you.

2 Thank you, Mr. Chairman.

3 CHAIRMAN WHITFIELD: Thank you, Commissioner
4 Randall.

5 Commissioner Fleming.

6 EXAMINATION

7 BY COMMISSIONER FLEMING:

8 Q Yes, Mr. Rooks.

9 A [R00KS] Yes, ma'am.

10 Q Mr. Shinn testified about the allowances that they were
11 able to sell during the review period?

12 A [R00KS] Correct.

13 Q The environmental allowances. How does the company
14 account for the sale of emissions allowances?

15 A [R00KS] They would be used as a reduction or a credit to
16 our environmental expense. And I believe Exhibit -4 in
17 the month of October 2017, you can actually see – if
18 I've turned to the correct exhibit, here. Yes. You can
19 see the reduction that's made there for NO_x allowances.

20 Q Okay. NO_x and SO_x, or just NO_x?

21 A [R00KS] In this case, it was just NO_x.

22 Q Okay. Are any gains derived from the sale of allowances
23 used to offset the fuel or environmental costs?

24 A [R00KS] Any proceeds from those sales, I believe, would
25 be used to reduce environmental costs.

1 Q Okay. And, also, I wanted to ask you about the tax
2 issue, Section 174? And as I understand it – well, what
3 I wanted to find out, I know you – it wasn't used.

4 A [ROOKS] Correct.

5 Q And, so, what happens now? Are those benefits just
6 lost?

7 A [ROOKS] No. They'll be considered as part of our merger
8 and abandonment filing, in that docket.

9 Q Okay. So you've just pushed them forward a bit.

10 A [ROOKS] Yeah, essentially, from – and, certainly, this
11 is not my subject-matter expertise. But in Mr. Coffey's
12 testimony in last year's proceeding, those deductions
13 can only be taken one time for that investment. So to
14 the extent that none were recognized in the customer
15 rates, they're still out there; they're still available,
16 and they'll be addressed along with the other
17 abandonment deductions in that particular docket.

18 Q Okay. Thank you.

19 And Mr. Raftery.

20 A [RAFTERY] Yes.

21 Q I believe you're the one to ask. I have understood and
22 heard in hearings through the several years, and even
23 during this hearing, that there are a lot of
24 opportunities out there for SCE&G for energy efficiency
25 and demand-side management. Would you agree with that?

1 **A** [RAFTERY] There are. I would recall in the ORS's
2 comments to our DSM filing in January the recognition
3 that we have increased year-over-year seven of the eight
4 programs' participation in energy savings, and then in
5 our filing, the indication of a Potential Study to be
6 conducted this year to really address what are the
7 opportunities to introduce new programs as part of our
8 DSM portfolio, to include some of the conversations
9 around demand reduction.

10 **Q** So you think there would be a robust attempt to take
11 care of those reductions that are out there?
12 Opportunities that are out there?

13 **A** [RAFTERY] It will be a complete assessment, starting
14 with the technical analysis of all of the energy that
15 technically could be accounted for in an energy
16 efficiency program here in the State. It will also look
17 at the economic opportunity and all of the cost-
18 effectiveness tests that the programs – outside of low-
19 income – need to pass. And then it will be very
20 specific to our service territory and what we can
21 achieve. I'm not sure if I'd say "robust" but it
22 certainly will be comprehensive and complete, and I do
23 know that we will have some challenges. Dr. Lynch put
24 in 100 megawatts for that winter-peak demand reduction.
25 That's a tall order. In conversations I've had with

1 neighboring utilities, most recently with Duke Energy
2 Carolinas and Duke Energy Progress, some of their
3 demand-reduction programs for residential customers
4 really just get about 1 kilowatt per participant. So in
5 order to hit that 100 megawatts of demand reduction,
6 we'd have to have 100,000 customers participate, so
7 really one out of six or one out of seven customers
8 would need to participate in that program, and that
9 would be, you know, in recognition for maybe a \$24 or
10 \$32 bill credit each year. So it's a tall order, but
11 that Potential Study is going to help us honestly and
12 completely analyze that opportunity.

13 **Q** Would it reduce the reserve margin that has been
14 estimated that's needed?

15 **A** [RAFTERY] Could I pass that to Dr. Lynch?

16 **Q** If you'll answer it quickly. Yes or no?

17 [Laughter]

18 **A** [LYNCH] Doesn't reduce the reserve margin, but it solves
19 a capacity problem. Reserve margin says this is how
20 much resources we need, and demand response would be
21 part of those resources.

22 **Q** Honestly, I'm shocked at the reserve margin of 21
23 percent. I mean, I don't remember, even combining what
24 you think of summer and winter – since I've been on the
25 Commission, that is really shocking, and, I mean, it

1 almost looks like, I mean, that would be something you'd
2 use to come forth for a new facility, it seems like, and
3 I believe you did talk about that with the CT and
4 combined-combustion.

5 A [LYNCH] Can I testify if I'm quick?

6 Q No. I mean, we had that before; that's what I was
7 afraid you were getting into again, but that was
8 transmission loss. I'm sorry.

9 A [LYNCH] Well, no, just a real quick point is that the
10 summer risk is 500 megawatts. I think you can take that
11 to the bank. I mean, the winter risk is 500 megawatts;
12 the summer risk is 200. So there's a 300-megawatt Delta
13 that's real that represents about 6 percent of capacity.
14 So if 14 percent is good in the summer, you're in the
15 neighborhood of 20 percent in the winter. There's no
16 way around that. That doesn't mean you have to build to
17 that capacity. Demand response will help, you know,
18 whatever you're going to do. But the risk is there. I
19 mean, that's - I don't know how to get around that, if
20 you see what I'm saying.

21 COMMISSIONER FLEMING: All right, great.

22 Thank you.

23 CHAIRMAN WHITFIELD: Thank you, Commissioner
24 Fleming.

25 Commissioner Howard or Hamilton, I believe

1 you're the only two that haven't —

2 **COMMISSIONER HAMILTON:** I think my questions —

3 **COMMISSIONER HOWARD:** Mine's been answered.

4 **COMMISSIONER HAMILTON:** — have been answered
5 very well.

6 **CHAIRMAN WHITFIELD:** Asked and answered.

7 Okay.

8 **EXAMINATION**

9 **BY CHAIRMAN WHITFIELD:**

10 **Q** Okay. Quickly, I have a couple for you, and this —
11 we'll be done, I think, with Commissioner questions.
12 I've got one for you, Dr. Lynch, one or two, and then
13 one for you, Mr. Raftery. Dr. Lynch, you had a
14 discussion with Commissioner Bockman about solar not
15 being available in the winter, and I think what the
16 conclusion is, what you really are saying, is it's not
17 available during the peak time, that pre-daylight time
18 on the coldest of cold mornings on a winter peak. Is
19 that what you're saying?

20 **A** [LYNCH] Right. The solar's there, but it's not
21 generating. That's correct.

22 **Q** Not generating. It's not there at the time you need it,
23 whereas in the summer it is there?

24 **A** [LYNCH] To help serve the load.

25 **Q** To help serve the peak, all right.

1 A [LYNCH] Yes, sir.

2 Q That being said, and what Commissioner Fleming just
3 asked you about that 300-megawatt Delta that you have in
4 the winter, and I think you said that was 6 percent of
5 capacity, and you did answer Commissioner Fleming
6 somewhat about demand response, but how – and
7 Commissioner Bockman went down this path a little bit,
8 but I'm just not clear. How is the company replacing
9 this 300 megawatts in the winter?

10 A [LYNCH] All right. So we need 300 megawatts of
11 resources, and that's the need and that's the reserve
12 margin that says the 21 percent's what it is. Well, how
13 you meet that need, that customer need, can vary. One
14 way is with demand response. So if you get a spike,
15 maybe load control, so a customer can control his heat
16 pump, the strips, turn them off, or something like that,
17 and that reduces the demand. But you still have –
18 whatever that reduction is, that's part of your
19 resources, if you see what I'm saying. So somehow we
20 need to address this 21 percent, this 500 megawatts'
21 spike. Somehow you've got to worry about it, and demand
22 response would be one of the ways. Instead of building
23 a power plant, put in some of these demand-response
24 programs, like we do in the – like in the summer we have
25 300 megawatts; also in the winter we have our

1 interruptible program. We've already got that sort of
2 thing going on, but we need more of it because of this
3 winter risk that's showing.

4 **Q** All right. Thank you.

5 Mr. Raftery, I had an exchange with Mr. Delk
6 yesterday about the cogeneration facility, Kapstone, at
7 North Charleston, formerly MeadWestvaco, and he informed
8 me that a 20-year contract for that 85-megawatt
9 generator was in 1998 and it ends this year. Was that
10 something that the company – he didn't get into the
11 details of that arrangement, but is that something that
12 the company would like to have still had? And I'm
13 assuming this falls under your responsibilities. Is
14 that something the company would've liked to have kept,
15 going forward? I realize the paper companies always
16 brought the raw materials, the biomass, in for it, but
17 you're not even going to own the generator anymore.

18 **A** [RAFTERY] And, unfortunately, that is not something that
19 falls under my purview, so I'm not sure I could
20 accurately comment.

21 **Q** Dr. Lynch, is that under your purview?

22 **A** [LYNCH] Not directly, but I know something about it.

23 **Q** Well, please –

24 **A** [LYNCH] I can tell you what I know, if it helps. So I
25 think the company would've been fine keeping it, but the

1 I don't think there are any further questions,
2 and, if not, thank you for your testimony, and you
3 may step down – I'm sorry, hold on one second. Let
4 me check with your attorney.

5 MR. MUSTIAN: No redirect.

6 CHAIRMAN WHITFIELD: No redirect? Now you may
7 step down.

8 [WHEREUPON, the witnesses stood aside.]

9 And at this time, as they step down, Mr. Whitt
10 and Mr. Snowden, I'm going to call on you to
11 present your case.

12 MR. WHITT: Okay.

13 CHAIRMAN WHITFIELD: Your witness.

14 MR. WHITT: Well, I think we had an agreement,
15 Mr. Chairman, to let ORS' witness go first. They
16 had a time crunch more than our witness.

17 MR. BATEMAN: If the Commission would be
18 amenable, we would appreciate if Mr. Horii could –
19 I suppose Mr. Horii and Ms. Johnson could –

20 CHAIRMAN WHITFIELD: Well, I'm hoping time's
21 not going to be an issue, but if all the parties
22 are okay with that –

23 MR. BURGESS: SCE&G has no objection to that.

24 CHAIRMAN WHITFIELD: Okay.

25 MS. OTTENWELLER: [Nodding head.]

1 **CHAIRMAN WHITFIELD:** Then, go ahead –

2 **MR. BATEMAN:** Thank you, Mr. Chairman.

3 **CHAIRMAN WHITFIELD:** Go ahead, Mr. Bateman.

4 **MR. BATEMAN:** ORS would call to the stand Mr.
5 Horii and Ms. Johnson.

6 And as the witnesses are taking their seats,
7 we would again like to reiterate our thanks to the
8 Commission for allowing us to present via panel.

9 **CHAIRMAN WHITFIELD:** You're welcome.

10 [Witnesses affirmed]

11 THEREUPON came,

12 **S A R A H W . J O H N S O N ,**

13 **B R I A N K . H O R I I ,**

14 called as witnesses on behalf of the South Carolina Office of
15 Regulatory Staff, who, having been first duly affirmed, were
16 examined and testified as follows:

17 **DIRECT EXAMINATION**

18 **BY MR. BATEMAN:**

19 **Q** Ms. Johnson, would you please state your name and
20 occupation?

21 **A** [S. JOHNSON] My name is Sarah Johnson. I'm the deputy
22 director of Utility Services for the Office of
23 Regulatory Staff.

24 **Q** And are you the same Sarah Johnson who prefiled six
25 pages of direct testimony on March 23, 2018?

1 **A** [S. JOHNSON] I am.

2 **Q** If I asked you the same questions as those contained in
3 your prefiled direct testimony today, would your answers
4 remain the same?

5 **A** [S. JOHNSON] They would.

6 **MR. BATEMAN:** Mr. Chairman, ORS ask that Ms.
7 Johnson's prefiled direct testimony be entered into
8 the record as if given orally from the stand.

9 **CHAIRMAN WHITFIELD:** Ms. Johnson's prefiled
10 direct testimony will be entered into the record as
11 if given orally from the stand.

12 **BY MR. BATEMAN:**

13 **Q** Ms. Johnson, did you also prepare or cause to be
14 prepared a one-page exhibit marked SWJ-1, which was
15 filed with the Commission on March 23, 2018, as an
16 attachment to your prefiled direct testimony?

17 **A** [S. JOHNSON] I did.

18 **Q** Do you have any changes or corrections to your prefiled
19 exhibit?

20 **A** [S. JOHNSON] I do not.

21 **MR. BATEMAN:** Mr. Chairman, ORS asks that Ms.
22 Johnson's Exhibit SW- – excuse me – SJW – excuse me
23 – SWJ-1, attached to Ms. Johnson's prefiled direct
24 testimony, be entered into the record as the next
25 hearing exhibit in this case.

1 **CHAIRMAN WHITFIELD:** Ms. Johnson's Exhibit
2 SWJ-1 will be entered in as Hearing Exhibit No. 11.
3 [WHEREUPON, Hearing Exhibit No. 11 was
4 marked and received in evidence.]

5 **MR. BATEMAN:** Thank you.

6 **BY MR. BATEMAN:**

7 **Q** Ms. Johnson, did you prepare a summary of your prefiled
8 direct testimony?

9 **A** [S. JOHNSON] I did.

10 **Q** Would you please share your summary with the Commission?

11 **A** [S. JOHNSON] Certainly.

12 Good afternoon, Mr. Chairman and members of the
13 Commission.

14 The purpose of my testimony's to present ORS's
15 evaluation of DERP expenses from January 2017 to April
16 2019.

17 ORS reviewed the proposed annual DERP charges of
18 \$12 for Residential customers, \$64.39 for Small and
19 Medium General Service customers, and \$1200 for Large
20 General Service customers. ORS finds that the company's
21 DERP expenses were reasonably incurred and their
22 calculations are in compliance with Act 236 and
23 Commission Orders. The company updated the value of
24 Distributed Energy Resources in accordance with
25 Commission Order 2015-194.

1 This concludes my summary. .

2 MR. BATEMAN: Thank you, Ms. Johnson.

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23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED DIRECT TESTIMONY OF SARAH W.
25 JOHNSON FOLLOWS AT PGS 555-561]

THE OFFICE OF REGULATORY STAFF

DIRECT TESTIMONY & EXHIBIT

OF

SARAH W. JOHNSON

MARCH 23, 2018



DOCKET NO. 2018-2-E

**Annual Review of Base Rates for Fuel Costs for South
Carolina Electric & Gas Company**

DIRECT TESTIMONY AND EXHIBIT OF

SARAH W. JOHNSON

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-2-E

IN RE: ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS

FOR SOUTH CAROLINA ELECTRIC & GAS COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Sarah W. Johnson. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina 29201. I am employed by the State of South Carolina as the Deputy Director of Utility Services in the Utility Rates and Services Division of the Office of Regulatory Staff ("ORS").

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received my Bachelor of Science from the University of South Carolina in 1995. Prior to my employment with ORS, I held a variety of positions supporting both regulated and deregulated utility operations for electric, natural gas, and telecommunication providers across the southeast. My duties included customer service, information technology, product marketing, and regulatory consulting.

I joined ORS in 2016 as Deputy Director of Utility Services. In this role I supervise the daily activities related to the technical areas of Distributed Energy Resources, solar leasing, and Demand Side Management and Energy Efficiency. I am also responsible for the daily operations of the ORS Consumer Services Division.

1 **Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF**
2 **SOUTH CAROLINA (“COMMISSION”)?**

3 **A.** Yes. I have testified before the Commission in matters related to electric utility
4 annual fuel clause proceedings.

5 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

6 **A.** The purpose of my testimony is to set forth ORS’s recommendations resulting from
7 the examination of South Carolina Electric and Gas Company’s (“SCE&G” or
8 “Company”) Distributed Energy Resource Program (“DERP”) expenses for the period of
9 January 2017 through December 2017 (“Actual Period”), January 2018 through April 2018
10 (“Estimated Period”), and May 2018 through April 2019 (“Forecasted Period”).

11 **Q. WHAT EXPENSES RELATED TO THE COMPANY’S DERP ARE INCLUDED IN**
12 **THIS PROCEEDING?**

13 **A.** Pursuant to S.C. Code Ann. § 58-39-130(A)(2) (2015), an electrical utility with an
14 approved DERP may recover associated costs that are reasonably and prudently incurred,
15 and pursuant to S.C. Code Ann. § 58-39-140(F) (2015), cost recovery shall remain in force
16 until all approved DERP components have been recovered. The Company’s DERP was
17 approved in Commission Order No. 2015-512, and the Company included in this filing
18 actual and forecasted avoided and incremental costs for the period of January 1, 2017
19 through April 30, 2019.

20 **Q. PLEASE EXPLAIN THE INCLUSION OF DERP AVOIDED COSTS TO BE**
21 **RECOVERED IN THIS PROCEEDING.**

22 **A.** According to S.C. Code Ann. § 58-39-140 (2015), payments for electricity provided
23 under the DERP that are paid at avoided cost rates or rates negotiated pursuant to the Public

1 Utility Regulatory Policy Act of 1978 (“PURPA”), whichever is lower, are eligible to be
2 recovered through the DERP avoided cost component.

3 The Company incurred DERP avoided costs during the Actual Period for Bill
4 Credit Agreements (“BCAs”) paid to customers, purchased power from utility-scale solar
5 facilities, and excess net energy metering (“NEM”) payments to customers. These costs
6 were allocated using the same method the Company uses to allocate and recover variable
7 environmental costs. Actual and Estimated DERP avoided cost totals are shown in ORS
8 witness Smith’s Audit Exhibit GS-8.

9 **Q. WHAT TYPES OF EXPENSES HAS THE COMPANY INCLUDED AS DERP**
10 **INCREMENTAL COSTS?**

11 **A.** The Company included costs in excess of avoided costs, administrative and general
12 costs, NEM and BCA incentives, NEM future benefits, NEM performance based
13 incentives, depreciation costs, and associated carrying costs. Actual and estimated cost
14 totals are shown in ORS witness Smith’s Exhibit GS-9. Exhibit SWJ-1 reflects the under-
15 recovered and total estimated and forecasted incremental costs.

16 **Q. DID THE ORS FIND THE COMPANY’S DERP AVOIDED AND INCREMENTAL**
17 **COSTS TO BE REASONABLE?**

18 **A.** Yes. ORS met with Company personnel to discuss continued DERP
19 implementation, to evaluate the prudence and reasonableness of expenses, and review the
20 Company’s methodology for allocating and recovering DERP expenses. ORS found the
21 Company’s DERP avoided and incremental costs to be reasonably and prudently incurred
22 in implementing the Company’s DERP. As of this proceeding, the Company has met the
23 Customer Scale and Utility Scale goals of Act 236, and has incurred reasonable expenses

1 to achieve those goals. ORS also reviewed the Company's Estimated and Forecasted DERP
2 avoided and incremental costs, which include costs for implementation of the Company's
3 Community Solar Program, and found them to be reasonable.

4 **Q. PLEASE EXPLAIN THE DERP CHARGE PER ACCOUNT.**

5 **A.** The fixed charge by which the Company proposes to recover DERP incremental
6 costs ("DERP Charge") is determined by allocating DERP incremental expenses in the
7 same way the Company allocates variable environmental expenses. The revenue is
8 collected as a fixed charge per account to ensure that no account charge exceeds the annual
9 recovery caps prescribed in S.C. Code Ann. § 58-39-150 (2015).

10 **Q. WILL THE PROPOSED ANNUAL DERP CHARGES RECOVER ALL THE**
11 **INCREMENTAL COSTS?**

12 **A.** No. The proposed Residential and Large General Service DERP Charges will not
13 recover all the incremental costs allocated to those customer classes. A full recovery of
14 DERP incremental costs would require an annual DERP charge of \$16.90 for Residential
15 customers and \$16,455.05 for Large General Service customers. However, the annual
16 recovery caps prescribed in S.C. Code Ann. § 58-39-150 (2015) limit the amount
17 Residential and Large General Service customers can be charged each year to \$12.00 and
18 \$1,200.00 respectively. SCE&G's proposed annual DERP charge will recover all DERP
19 incremental costs from Small and Medium General Service customers as the cost is under
20 the \$120.00 annual recovery cap for that class.

21 **Q. HOW WILL UNDER-COLLECTED INCREMENTAL COSTS BE TREATED?**

22 **A.** Under-collected incremental costs will be treated in the same manner other fuel and
23 fuel-related under collected balances are treated. The under-collection will earn carrying

1 costs until next year when it will be reallocated using each class's contribution to peak
2 demand.

3 **Q. DOES ORS HAVE ANY FURTHER RECOMMENDATIONS REGARDING THE**
4 **AVOIDED COST COMPONENTS OR DERP CHARGES PROPOSED BY THE**
5 **COMPANY?**

6 **A.** No. ORS finds that the Company's calculations are in compliance with the
7 Distributed Energy Resource Program Act and with the Commission's orders in previous
8 DERP-related proceedings and supports the following annual proposed DERP Charges:
9 Residential \$12.00, Small and Medium General Service \$64.39, and Large General Service
10 \$1,200.00. Exhibit SWJ-1 details the totals by class.

11 **Q. DID THE COMPANY UPDATE THE VALUE OF DISTRIBUTED ENERGY**
12 **RESOURCES?**

13 **A.** Yes. As shown in Company witness Lynch's direct testimony (page 27), SCE&G
14 proposes a total value of NEM distributed generation of \$0.03329 over a one (1)-year
15 planning horizon and \$0.03264 over a fifteen (15)-year planning horizon. The one (1)-year
16 value is used by the Company to determine the NEM incentive. The Company then uses
17 the difference between the one (1)-year value and fifteen (15)-year value to determine the
18 NEM future benefits.

19 A significant change in the updated value of distributed generation is the reduction
20 of the avoided capacity value to zero. ORS witness Horii discusses the Company's
21 methodology and the change to avoided capacity in more detail in his testimony.

22 **Q. IS THE COMPANY'S CALCULATION OF THE NEM INCENTIVE**
23 **CONSISTENT WITH DOCKET NO. 2014-246-E?**

1 **A.** Yes. The Company used the methodology approved in Commission Order No.
2 2015-194 to calculate the NEM incentive. SCE&G determined the difference between the
3 expected revenues from NEM customers with and without DERP. Once the revenue gap
4 was identified, the value of the customers' distributed generation was calculated using the
5 amount from the NEM tariff approved in Commission Order No. 2017-246 in Docket No.
6 2017-2-E. The outstanding revenue was divided by the number of kilowatt hours the
7 customers of each applicable rate schedule generated to calculate the NEM incentive.

8 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

9 **A.** Yes.

1 **BY MR. BATEMAN:**

2 **Q** Mr. Horii, would you please state your name and
3 occupation?

4 **A** [HORII] Yes, my name is Brian Horii. I am a senior
5 partner at Energy and Environmental Economics, and my
6 business address is 101 Montgomery Street, San
7 Francisco, California.

8 **Q** Thank you, Mr. Horii. Are you the same Brian Horii who
9 prefiled 25 pages of direct testimony in this case on
10 March 23, 2018?

11 **A** [HORII] Yes, I am.

12 **Q** If I asked you the same questions as those contained in
13 your prefiled direct testimony, would your answers
14 remain the same?

15 **A** [HORII] No, I have three small corrections to my
16 testimony. Starting on page 18, at Table 5, the value
17 for 2021 should be changed from 3.1 percent to 2.1
18 percent. Then on page 20, Table 7, the value for 2021
19 should be changed from 2.9 percent to 1.9 percent. And,
20 finally, on page 22, line 14, the word "update" should
21 be changed to "uptake."

22 **Q** Thank you, Mr. Horii. And just to confirm, that was
23 your direct testimony; is that correct?

24 **A** [HORII] Yes, that is correct.

25 **Q** And are you the same Brian Horii who prefiled 16 pages

1 of surrebuttal testimony in this case on April 4, 2018?

2 A [HORII] Yes.

3 Q If I asked you the same questions today as those
4 contained in your surrebuttal, would your answers remain
5 the same?

6 A [HORII] Yes.

7 MR. BATEMAN: Mr. Chairman, at this point in
8 time, ORS asks that the prefiled direct testimony,
9 with corrections as just mentioned by Mr. Horii, as
10 well as the prefiled surrebuttal testimony of Mr.
11 Horii be read into the record as if given orally
12 from the stand.

13 CHAIRMAN WHITFIELD: Mr. Horii's prefiled
14 direct testimony, with corrections, and Mr. Horii's
15 surrebuttal testimony will be entered into the
16 record as if given orally from the stand.

17 MR. BATEMAN: Thank you.

18 BY MR. BATEMAN:

19 Q Mr. Horii, did you also prepare or cause to be prepared
20 a seven-page exhibit marked BKH_[sic]-1, which was filed as
21 an attachment to your prefiled direct testimony?

22 A [HORII] Yes.

23 Q Do you have any changes or corrections to your prefiled
24 exhibit?

25 A [HORII] No, I do not.

1 **MR. BATEMAN:** Mr. Chairman, ORS asks that Mr.
2 Horii's exhibit attached to his prefiled direct
3 testimony be entered into the record of this case
4 as the next hearing exhibit.

5 **CHAIRMAN WHITFIELD:** Mr. Horii's Exhibit
6 BKH_[sic]-1 will be entered in as Hearing Exhibit No.
7 12.

8 [WHEREUPON, Hearing Exhibit No. 12 was
9 marked and received in evidence.]

10 **MR. BATEMAN:** Thank you.

11 **BY MR. BATEMAN:**

12 **Q** Mr. Horii, did you also prepare or cause to be prepared
13 a two-page surrebuttal exhibit marked Surrebuttal
14 Exhibit BHK-1_[sic], which was filed as an attachment to
15 your prefiled surrebuttal testimony?

16 **A** [HORII] Yes.

17 **Q** Do you have any changes or corrections to your prefiled
18 exhibit?

19 **A** [HORII] No.

20 **MR. BATEMAN:** Mr. Chairman, ORS asks that Mr.
21 Horii's surrebuttal exhibit attached to his
22 surrebuttal testimony be entered into the record of
23 this case as the next hearing exhibit.

24 **CHAIRMAN WHITFIELD:** Mr. Horii's Surrebuttal
25 Exhibit BHK-1_[sic] will be entered in as Hearing

1 Exhibit No. 13.

2 [WHEREUPON, Hearing Exhibit No. 13 was
3 marked and received in evidence.]

4 MR. BATEMAN: Thank you, Mr. Chairman. Mr.
5 Chairman, just to clarify, I don't have his exhibit
6 to the direct testimony right in front of me, but I
7 think it may inadvertently be mislabeled "BHK-1."
8 I just wanted to ensure that the exhibit to his
9 prefiled direct, whether it was BHK or BKH be
10 marked and entered into the record as a hearing
11 exhibit, and I believe you said 11.

12 CHAIRMAN WHITFIELD: I do note that his
13 Surrebutta] has "BHK_[sic]," and those initials are
14 noted that they are reversed, but we did identify
15 it as his surrebuttal.

16 MR. BATEMAN: Okay. Thank you.

17 CHAIRMAN WHITFIELD: So noted.

18 BY MR. BATEMAN:

19 Q Mr. Horii, did you prepare a summary of your testimony?

20 A [HORII] I did.

21 Q Would you please share your summary with the Commission?

22 A [HORII] Good afternoon, Mr. Chairman, and members of the
23 Commission.

24 ORS retained me in reviewing SCE&G's avoided cost
25 calculations, specifically to (1) verify the company is

1 using the avoided cost methodology approved by the
2 Commission; (2) confirm the methodology meets the PURPA
3 requirements; (3) verify the avoided cost rates
4 requested by SCE&G are a reasonable result of the
5 approved avoided cost methodology; (4) verify the
6 company has populated each of the 11 categories in the
7 value of DER according to the methodology established in
8 Order No. 2015-194; (5) confirm, for each category with
9 a value of zero, that the company does not have
10 sufficient capability to accurately quantify those costs
11 or benefits to the utility system; and (6) verify for
12 each category with a value other than zero that the
13 value assigned is a reasonable result of the company's
14 ability to accurately quantify the costs or benefits to
15 the utility system.

16 With respect to energy avoided costs, I note that
17 SCE&G did change the resource increment to reflect a
18 100-megawatt solar resource instead of a 100-megawatt
19 base-load unit. However, I believe that their approach
20 is still consistent with the prior methodology and
21 PURPA, and that their energy avoided costs are
22 reasonable.

23 With respect to the 11 categories in the value of
24 DER, I find all of SCE&G's results reasonable, with the
25 exception of their setting the capacity value to zero.

1 I disagree with the company's declaration that there is
2 no capacity value for incremental solar and object to
3 their refusal to calculate a capacity value for non-
4 solar resources in this docket. SCE&G bases its
5 assertion of zero avoided capacity costs for solar
6 products on SCE&G being constrained by winter capacity
7 needs and unaided by summer capacity additions. This is
8 a substantial change from the methodology and inputs
9 used by SCE&G to calculate PR-1 and PR-2 rates, and
10 relies upon assumptions and studies conducted in the
11 2018 IRP that have not been fully reviewed and vetted.

12 Given the large change in SCE&G's position and the
13 uncertainty over the accuracy of its new position, I
14 recommend that SCE&G's position of zero avoided capacity
15 costs be rejected at this time.

16 To illustrate the uncertainty over the accuracy of
17 SCE&G's new position, I show in my testimony that there
18 are flaws in SCE&G's 2017 Reserve Margin Study and 2018
19 IRP to hide the actual need for summer capacity over
20 winter capacity in many years. The need for summer
21 capacity over winter capacity would indicate that there
22 would be a capacity value from incremental solar and
23 that SCE&G's position of zero capacity costs should
24 therefore be rejected.

25 The specific flaws that I identified in SCE&G's

1 analysis are: (1) an overly high estimate of winter
2 planning reserve margin because of an overestimate of
3 the winter demand-side risk due to a flawed regression
4 analysis; and (2) a bias in the IRP load forecast that
5 overestimates winter peak demand compared to the summer
6 peak demand. Both flaws make it appear that winter
7 capacity is more crucial than it actually is.

8 In place of SCE&G's position of zero capacity
9 costs, I recommend that SCE&G be directed to calculate
10 an avoided capacity cost value for a standard 100-
11 megawatt resource and that 19.5 percent of that value be
12 used to set the PR-1 and PR-2 capacity avoided costs.
13 The 19.5 percent factor is SCE&G's estimate of the
14 coincidence of incremental solar-farm production with
15 SCE&G's summer peak demand.

16 I similarly recommend that SCE&G produce a capacity
17 cost that can be used for PR-2 – the PR-2 rate for non-
18 solar resources. If SCE&G cannot provide an estimate
19 that can be vetted by parties in this docket, then I
20 recommend that the current PR-1 and PR-2 avoided
21 capacity cost components be retained until this issue
22 can be revisited in the next rate filing.

23 I also sponsor surrebuttal testimony to address the
24 rebuttal testimony of SCE&G Witness Lynch. My testimony
25 adds to the record by correcting misleading or erroneous

1 statements made by SCE&G.

2 And I think in the interest of time, I'll stop my
3 summary there. Thank you.

4 **Q** Thank you, Mr. Horii. - I do have a question. I may have
5 misheard you. You mentioned, a second ago, that SCE&G
6 bases its assertion of zero avoided capacity cost for
7 solar projects on SCE&G being constrained by winter
8 capacity needs and unaided by summer capacity additions?
9 Did you say additions or reductions?

10 **A** [HORII] That would be unaided by capacity addition from
11 solar or, I guess the reverse way, you could think of it
12 as aided by summer capacity sort of reductions by
13 customers. So it's sort of that resource-balance issue.
14 But in either case, summer capacity is important.

15 **MR. BATEMAN:** Okay. Thank you for clarifying
16 that for me.

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23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED DIRECT TESTIMONY {W/CORRN'S} OF
25 BRIAN K. HORII FOLLOWS AT PGS 570-595]

THE OFFICE OF REGULATORY STAFF
DIRECT TESTIMONY & EXHIBIT
OF
BRIAN HORII
MARCH 23, 2018



DOCKET NO. 2018-2-E

**Annual Review of Base Rates for Fuel Costs for South
Carolina Electric & Gas Company**

DIRECT TESTIMONY AND EXHIBIT

OF

BRIAN HORII

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-2-E

IN RE: ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS FOR

SOUTH CAROLINA ELECTRIC & GAS COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Brian Horii. My business address is 101 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3") and have been retained by the South Carolina Office of Regulatory Staff ("ORS") to assist in the analysis of South Carolina Electric & Gas Company's ("SCE&G" or "Company") avoided capacity cost and avoided energy cost calculations, and review the Value of NEM methodology, in this Docket.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have thirty (30) years of experience in the energy industry. My areas of expertise include avoided costs, utility ratemaking, cost-effectiveness evaluations, transmission and distribution planning, and distributed energy resources. Prior to joining E3 as a partner in 1993, I was a researcher in Pacific Gas and Electric Company's ("PG&E") Research & Development department, and was a supervisor of electric rate design and revenue allocation. I have testified before commissions in California, British Columbia, and

1 Vermont, and have prepared testimonies and avoided cost studies for utilities in New York,
2 New Jersey, Texas, Missouri, Wisconsin, Indiana, Alaska, Canada and China.

3 I received both a Bachelor of Science and Master of Science degree in Civil
4 Engineering and Resource Planning from Stanford University. My full curricula vita is
5 provided as Exhibit BKH-1.

6 **Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE**
7 **COMMISSION OF SOUTH CAROLINA (“COMMISSION”)?**

8 **A.** Yes, I testified before this Commission on behalf of ORS in reviewing SCE&G’s
9 avoided cost calculations.

10 **Q. WHY WERE YOU RETAINED BY ORS IN THIS PROCEEDING?**

11 **A.** ORS retained E3 to once again assist in reviewing SCE&G’s avoided cost
12 calculations to:

- 13 1) Verify the Company is using the avoided cost methodology approved by the
14 Commission;
- 15 2) Confirm the methodology meets the Public Utility Regulatory Policies Act of
16 1978 (“PURPA”) requirements; and
- 17 3) Verify the avoided cost rates requested by SCE&G in this Docket are a
18 reasonable result of the approved avoided cost methodology.

19 ORS also retained E3 to conduct an analysis of the SCE&G’s Value of Distributed Energy
20 Resource (“DER”) calculation to:

- 21 1) Verify the Company has populated each of the eleven (11) categories according
22 to the methodology established in Order No. 2015-194;

- 1 2) Confirm, for each category with a value of zero, that the Company does not
2 have sufficient capability to accurately quantify those costs or benefits to the
3 utility system; and
- 4 3) Verify, for each category with a value other than zero, that the value assigned
5 is a reasonable result of the Company's ability to accurately quantify the costs
6 or benefits to the utility system.

7 My prior work experience in this subject matter includes the following:

- 8 • Developed the methodology for calculating avoided costs used by the
9 California Public Utilities Commission for evaluation of Distributed Energy
10 Resources since 2004;
- 11 • Developed the methodology for calculating avoided costs used by the
12 California Energy Commission for evaluation of building energy programs;
- 13 • Authored avoided cost studies for BC Hydro, Wisconsin Electric Power
14 Company, and PSI Energy;
- 15 • Provided review of, and corrections to, PG&E avoided cost models used in their
16 general electric rate case;
- 17 • Developed the integrated planning model used by Con Edison and Orange and
18 Rockland Utilities to determine least cost DER supply plans for their network
19 systems;
- 20 • Developed the hourly generation dispatch model used by El Paso Electric
21 Company to evaluate the marginal cost impacts of their off-system sales and
22 purchases;

- 1 • Produced publicly vetted tools used in California for the evaluation of energy
- 2 efficiency programs, distributed generation, demand response, and storage
- 3 programs;
- 4 • Analyzed the cost impacts of electricity generation market restructuring in
- 5 Alaska, Canada, and China; and
- 6 • Developed the “Public Tool” used by California stakeholders to evaluate Net
- 7 Energy Metering program revisions in California.

8 **Q. PLEASE BRIEFLY DESCRIBE THE REQUIREMENTS OF PURPA AND HOW**
9 **THEY RELATE TO THE PR-1 AND PR-2 RATE SCHEDULES PROPOSED BY**
10 **THE COMPANY.**

11 **A.** In 1978, as part of the National Energy Act, Congress passed PURPA which was
12 designed, among other things, to encourage conservation of electric energy, increase
13 efficiency in use of facilities and resources by utilities, and produce more equitable retail
14 rates for electric consumers.

15 To help accomplish PURPA goals, a special class of generating facilities called
16 Qualifying Facilities (“QFs”) was established. QFs receive special rate and regulatory
17 treatments, including the ability to sell capacity and energy to electric utilities. All electric
18 utilities, regardless of ownership structure, must purchase energy and/or capacity from,
19 interconnect to, and sell back-up power to a QF. This obligation is waived if the QF has
20 non-discriminatory access to competitive wholesale energy and long-term capacity
21 markets.

22 In SCE&G’s service territory, Small Power Producers and Cogenerators that are
23 designated as QFs and have capacity less than or equal to 100 kilowatts (“kW”) are

1 compensated under SCE&G's Rate PR-1. Power purchased from QFs with capacity greater
2 than 100 kW and less than or equal to 80 megawatts ("MW") is compensated under
3 SCE&G's Rate PR-2

4 **Q. PLEASE DESCRIBE THE METHODOLOGY SCE&G USED IN THIS FILING TO**
5 **CALCULATE ITS AVOIDED ENERGY AND AVOIDED CAPACITY COSTS.**

6 **A.** SCE&G calculates avoided energy costs using the avoided cost methodology
7 known as the Differential Revenue Requirement ("DRR"). This method calculates the
8 revenue requirements associated with two (2) resource plan scenarios: a base case without
9 the QF, and a change case with the QF. This methodological framework is one of the
10 accepted methods for calculating PURPA avoided costs.

11 For the long-run avoided energy cost calculations, in both the base case and the
12 change case, SCE&G uses PROSYM, a production cost model, to simulate the
13 commitment of generating units to serve load on an hourly basis over a 15-year Integrated
14 Resource Plan ("IRP") planning horizon. The base case is constructed by using load
15 forecasts and supply side resources as described in the IRP. The change case modifies the
16 base case load forecast by subtracting zero-cost energy following the profile of a 100 MW
17 solar photovoltaic ("PV") generator. Finally, the avoided energy costs are levelized and
18 adjusted for taxes and working capital.

19 SCE&G has not provided a calculation for long-run avoided capacity costs.

20 **Q. IS THE METHOD USED BY SCE&G TO CALCULATE AVOIDED ENERGY**
21 **COSTS CONSISTENT WITH THE METHODOLOGY APPROVED BY THE**
22 **COMMISSION?**

1 A. Yes. The DRR methodology, as approved by the Commission in Order No. 2016-
2 297, supports various input models. In Docket Nos. 2016-2-E and 2017-2-E, SCE&G
3 calculated avoided energy costs by using the DRR approach modeling a QF with a constant
4 100 MW generation profile for the change case. In this Docket, SCE&G applies the DRR
5 approach modeling a QF with a solar profile for the change case. The shift of input models
6 for the change case from a constant profile to solar PV profile is a valid application of the
7 DRR methodology for the specific case of a solar generator.

8 **Q. PLEASE EXPLAIN WHY SHIFTING TO A SOLAR PROFILE IS AN**
9 **IMPROVEMENT OVER THE PRIOR METHOD.**

10 A. Previously a constant generator profile was used to calculate the difference in
11 revenue requirements between the base case and the change case, with costs collected into
12 four (4) time of use ("TOU") periods comprised of peak season and off-peak season, and
13 peak hours and off-peak hours within each season. The profile essentially assumed constant
14 solar output over the TOU period. Under the updated methodology, SCE&G derives a
15 change case by using a 100 MW solar profile. Given SCE&G's assertion that the vast
16 majority of recent and future QF resources are solar, it is an improvement to use an avoided
17 energy cost which more closely tracks the avoided energy for solar generation.

18 **Q. PLEASE DESCRIBE ANY OTHER UPDATES MADE BY SCE&G TO THE**
19 **AVOIDED ENERGY COSTS.**

20 A. In addition to the change as described above, changes in avoided energy costs are
21 driven by differences in fuel forecasts, load forecast, and in supply side resources as
22 reported in the 2018 IRP. In the 2017 IRP, SCE&G projected supply purchases from new
23 nuclear plants in 2020 and 2021. In the 2018 IRP, the construction of these nuclear plants

1 was canceled, with the capacity shortfall made up by increased solar and baseload
2 combined-cycle gas plants. This change in supply side resources likely had a small effect
3 on avoided energy cost calculation because the avoided energy cost is dependent on cost
4 for marginal units, and both nuclear and combined-cycle gas plants are listed as baseload
5 resources in the SCE&G IRP. I have reviewed the fuel price forecasts which SCE&G used
6 in calculating the avoided energy cost for both the 2017 and 2018 fuel adjustment
7 proceedings. These fuel price forecasts are consistent and similar. Finally, there is a slight
8 change in long-term annual sales growth (from 1.2% territorial sales growth annually to
9 1.1%) (SCE&G 2018 IRP). There appears to be no major changes in network
10 configurations or import/export assumptions used by SCE&G.

11 **Q. ARE THE UPDATES IN AVOIDED ENERGY COSTS A REASONABLE AND**
12 **CONSISTENT RESULT OF THE METHODOLOGY USED BY SCE&G?**

13 **A.** Yes. SCE&G applied the approved DRR methodology to calculate avoided energy
14 costs. SCE&G presents avoided energy costs calculated using a solar profile, as well as
15 avoided energy costs calculated using a constant 100 MW profile (Lynch, p. 11). Given
16 the relative similarity in fuel forecasts and minor changes in load, it is reasonable that the
17 avoided energy costs using the constant 100 MW do not change significantly from last
18 year. Furthermore, as SCE&G is proposing to set these avoided energy rates for solar
19 resources, it is reasonable to use a solar specific profile in calculating the avoided energy
20 costs. I agree with SCE&G's assertion that a solar generation profile can cause operational
21 and ramping issues which a constant profile does not cause. Thus, it is reasonable that the
22 avoided cost for energy using a solar profile is lower than the avoided cost for energy using
23 a constant energy profile.

1 Q. IN YOUR OPINION, IS THE METHOD USED BY SCE&G TO CALCULATE
2 AVOIDED ENERGY COSTS APPROPRIATE?

3 A. Yes, it is appropriate for solar generators.

4 Q. PLEASE DESCRIBE THE UPDATES MADE BY SCE&G TO THE AVOIDED
5 CAPACITY COSTS.

6 A. SCE&G has implemented a dramatic change in approach by not providing any
7 avoided capacity cost calculations in this proceeding.

8 Q. WHAT ARE SCE&G'S STATED REASONS FOR NOT PROVIDING ANY
9 CALCULATIONS OF AVOIDED CAPACITY COST?

10 A. Company witness Lynch asserts that new solar projects would not provide any
11 capacity reductions, so the avoided capacity value for the PR-2 rate is de-facto zero. He
12 further states that SCE&G will not offer the PR-2 rate to non-solar resources, so there is
13 no reason to provide an avoided capacity cost estimate in this proceeding. Further, when
14 ORS requested SCE&G to provide a calculation of avoided capacity costs for potential
15 non-solar resources, SCE&G did not provide any estimate, stating that it had no
16 information responsive to the request.

17 Q. DO YOU AGREE WITH SCE&G THAT NEW SOLAR PROJECTS WILL
18 PROVIDE NO CAPACITY VALUE?

19 A. No.

20 Q. WHAT IS THE BASIS FOR YOUR DISAGREEMENT WITH SCE&G ON THE
21 CONTRIBUTION OF SOLAR TOWARD REDUCING CAPACITY COSTS?

22 A. SCE&G asserts that "SCE&G needs as much capacity in the winter as it does in the
23 summer" (Lynch, p. 15) and "[b]ecause solar does not provide capacity during the winter

1 period, the Company is unable to avoid any of its projected future capacity.” (Lynch pp15-
2 16). SCE&G, however, has not adequately demonstrated that winter capacity needs are
3 the same or greater than summer capacity needs. If SCE&G capacity needs are instead
4 driven by the summer season, as SCE&G has historically stated (e.g.: SCE&G 2017 IRP
5 pp. 37-38), then incremental solar would continue to provide capacity benefits, and
6 incremental solar should therefore continue to receive avoided capacity cost compensation
7 in the PR-1 and PR-2 rate.

8 **Q. WHAT INFORMATION HAS SCE&G PROVIDED TO SUPPORT SCE&G BEING**
9 **CONSTRAINED BY WINTER CAPACITY?**

10 **A.** SCE&G states that “Since SCE&G’s Reserve Margin Study shows that SCE&G
11 needs as much capacity in the winter as it does in the summer, a resource has to provide
12 capacity in the winter as well as the summer in order to avoid the need for capacity and
13 thereby have capacity value.” (Lynch, p. 15). The reserve margin study states that SCE&G
14 requires 50% more capacity reserves in the winter as compared to the summer (21% vs
15 14% reserve margin). Referring to the SCE&G forecast of summer and winter loads and
16 resources from their 2018 IRP in Exhibit JML-1, one sees that, in many years, the winter
17 reserve margin target of 21% would be violated before the summer reserve margin target
18 of 14%.

19 **Q GIVEN THAT INFORMATION, WHAT ARE YOUR CONCERNS WITH**
20 **SCE&G’S POSITION OF ZERO AVOIDED COST FOR INCREMENTAL**
21 **SOLAR?**

22 **A.** SCE&G has not provided a straightforward update to its avoided capacity cost
23 estimates in this Docket. Rather than simply updating inputs used to estimate the avoided

1 capacity cost, SCE&G introduced a new concept of 100% winter capacity constraints as
2 the basis for not calculating any avoided capacity cost. I have concerns that parties have
3 not had adequate opportunity to evaluate the accuracy of this winter capacity constraint.
4 In addition, the flaws and inconsistencies in SCE&G's 2017 Reserve Margin study make
5 this process even more difficult. For example, only through conversations with SCE&G
6 witnesses was I informed of the differences in the data SCE&G used to derive their
7 regression models of seasonal weather response. This data was not provided when ORS
8 requested SCE&G to provide all of the support calculations and documentation to
9 substantiate its calculations. Those differences substantially sidetracked and delayed our
10 analysis of the reasonableness of SCE&G's study. Other parties, not informed of the data
11 inconsistency, may have been similarly misdirected.

12 SCE&G's assertion that there are no avoided capacity costs for fifteen (15) years if
13 there are no winter capacity reductions, strikes me as a position that requires that the winter
14 capacity constraint be nearly indisputable. I do not believe that SCE&G has proven that
15 condition. They may be correct, but given the large shift in approach and shift in the way
16 one would think about capacity needs, I believe that SCE&G's position should not be
17 adopted in this Docket.

18 **Q. YOU MENTIONED THE DIFFICULTY IN EVALUATING SCE&G'S FILINGS,**
19 **BUT ARE THERE ANY SPECIFIC ISSUES THAT YOU COULD IDENTIFY?**

20 **A.** Yes, I believe that SCE&G is overestimating the amount of excess capacity the
21 utility needs in the winter season because of a flawed 2017 Reserve Margin Study
22 ("Study"). I also believe the Company is forecasting summer and winter peak demands

for future years in an inconsistent manner that creates a potentially false indication of higher capacity need for the winter season.

Q. HOW IS SCE&G'S 2017 RESERVE MARGIN STUDY FLAWED?

A. The study (Exhibit JML-2) starts with a very simplistic method of simply adding together estimated peak variation from weather and variation in supply capacity to arrive at "Total Reserve MWs". This is done separately for the summer and winter season and divided by the summer and winter peak loads to arrive at the Reserve Margin Percentage (Exhibit JML-2, p. 8). These calculations are shown in Table 4 of the study, reproduced below.

Table 1: Reproduction of Table-4, Exhibit JML-2, p. 8

Reserve Margin for Summer and Winter Peak Periods		
	Summer	Winter
VACAR Operating	200	200
Demand-Side Risk	208	542
Supply-Side Risk	230	224
Total Reserve MWs	638	966
Normal Peak Demand	4744	4630
Reserve Margin %	13.4%	20.9%
Reserve Margin Policy	14%	21%

To my knowledge, this is not an industry standard approach (in contrast to the industry standard approaches such as the Loss of Load Probability method presented by SCE&G in its prior 2012 Reserve Margin Study).

Setting aside, however, the appropriateness of the method, the implementation of the method is flawed because SCE&G's determination of the winter season peak demand variation is overstated. By overstating the winter variability, SCE&G would be overstating the need for reserve margin in the winter. Indeed, in looking at Table-4 reproduced above,

one sees that the variation in peak demand (called the “Demand-Side Risk” in the table) accounts for the entirety of the increase in the winter reserve margin over the summer reserve margin.

To emphasize this point, the table below shows the exact same reserve margin calculations, but replaces SCE&G’s estimate of winter demand-side risk with an estimate I produced using SCE&G’s data (once I was informed of the data inconsistency problem with their provided data). The table shows that with E3’s demand-risk, the amount of extra capacity required in the winter compared to summer is only 211 MW (849 MW – 638 MW) --- not 328 MW as SCE&G claims.

Table 2: Reserve Margin with Alternate Winter Peak Variation

Reserve Margin for Summer and Winter Peak Periods			Difference
	Summer	Winter	
VACAR Operating	200	200	211
Demand-Side Risk	208	425	
Supply-Side Risk	230	224	
Total Reserve MWs	638	849	
Normal Peak Demand	4744	4630	4.9%
Reserve Margin %	13.4%	18.3%	

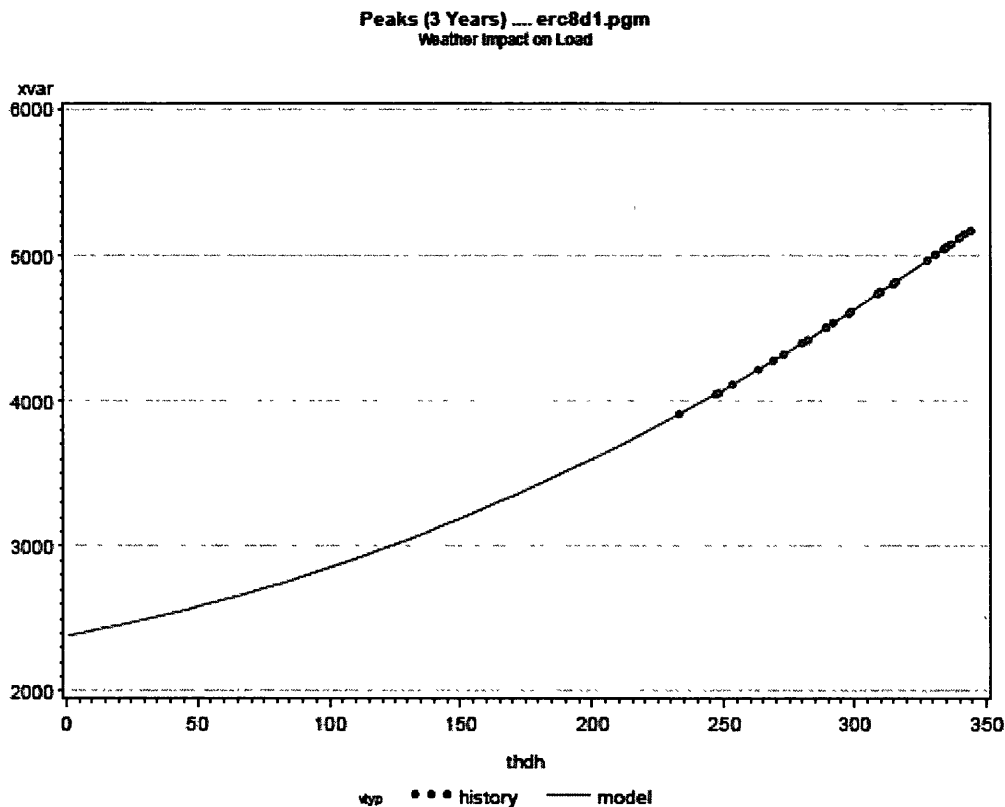
With this change, the winter reserve margin drops 2%, and the gap between the winter and summer reserve margins drops from 7% (21% - 14%) to about 5%.

Q. WHY DO YOU BELIEVE THAT SCE&G HAS OVERSTATED THE WINTER VARIABILITY?

A. SCE&G uses regression equations to estimate what peak demand would be on SCE&G’s system today given the weather that occurred on historical peak days since 1991. The lower figure on Exhibit JML-2, page 4, shows the estimated peak demands from the winter regression equation, with the points corresponding to the historical peak day

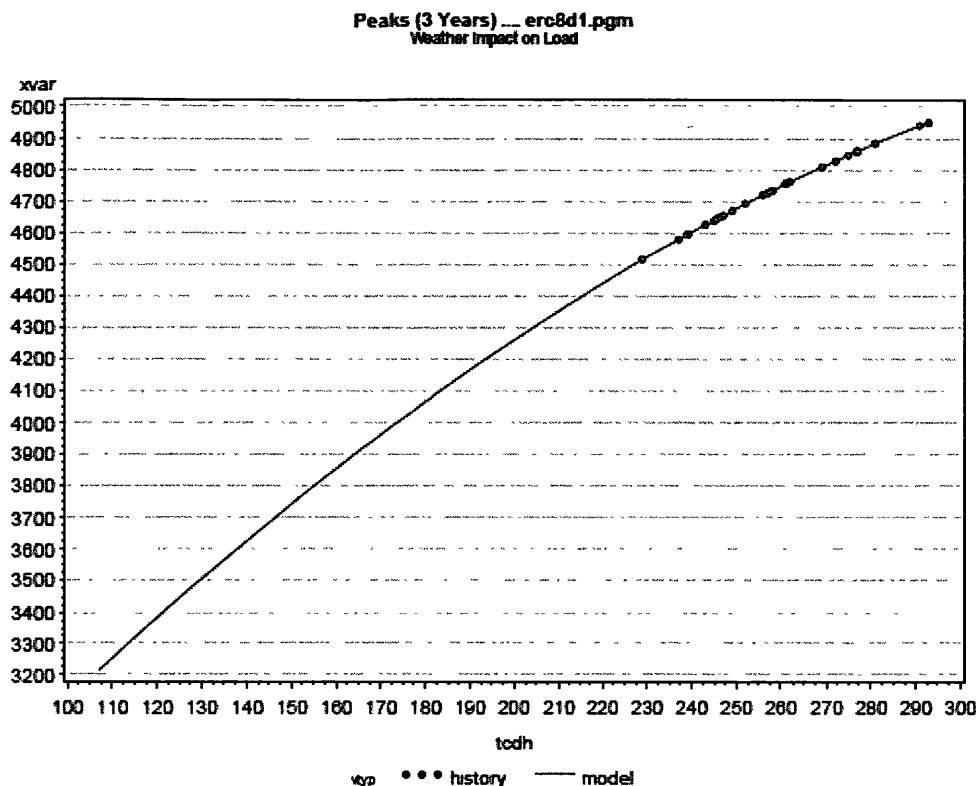
temperatures and corresponding simulated peak loads indicated by the black dots. The figure is reproduced below. The x-axis is cooling degree hours. They represent the sum of the differences between a design temperature, say 60 degrees, and the actual temperature in each hour of the day. The colder the day, the higher the cooling degree hours.

Figure 1: SCE&G Estimate of Winter Peak Demand using Historical Weather (Exhibit JML-2, p. 4)



Note the shape of the regression line. It slopes upward at an increasing rate, so that it predicts that peak load will rise at an ever increasing rate as the days get colder. Contrast that to the shape of SCE&G's predicted peak loads in the summer. In the summer figure, reproduced below, the rate of increase declines as weather becomes more extreme. This is indicated by the slight downward curve of the regression results.

Figure 2: SCE&G Estimate of Summer Peak Demand using Historical Weather (Exhibit JML-2, p. 4)



The summer shape is what I would expect. As weather becomes more extreme, the cooling equipment becomes more heavily used, but eventually top out and cannot increase electricity usage any further. As individual units top out, one sees diminishing increases in load as temperatures worsen.

In contrast, the winter shape has an upward curve, which is counter to engineering-based expectations. This upward curve also exacerbates the variation in peak demand, compared to the downward curve of the summer predictions. This can result in an overly large estimate of winter variability for the winter season compared to the summer season.

Q. WHAT IS YOUR ESTIMATE OF SCE&G WINTER VARIABILITY?

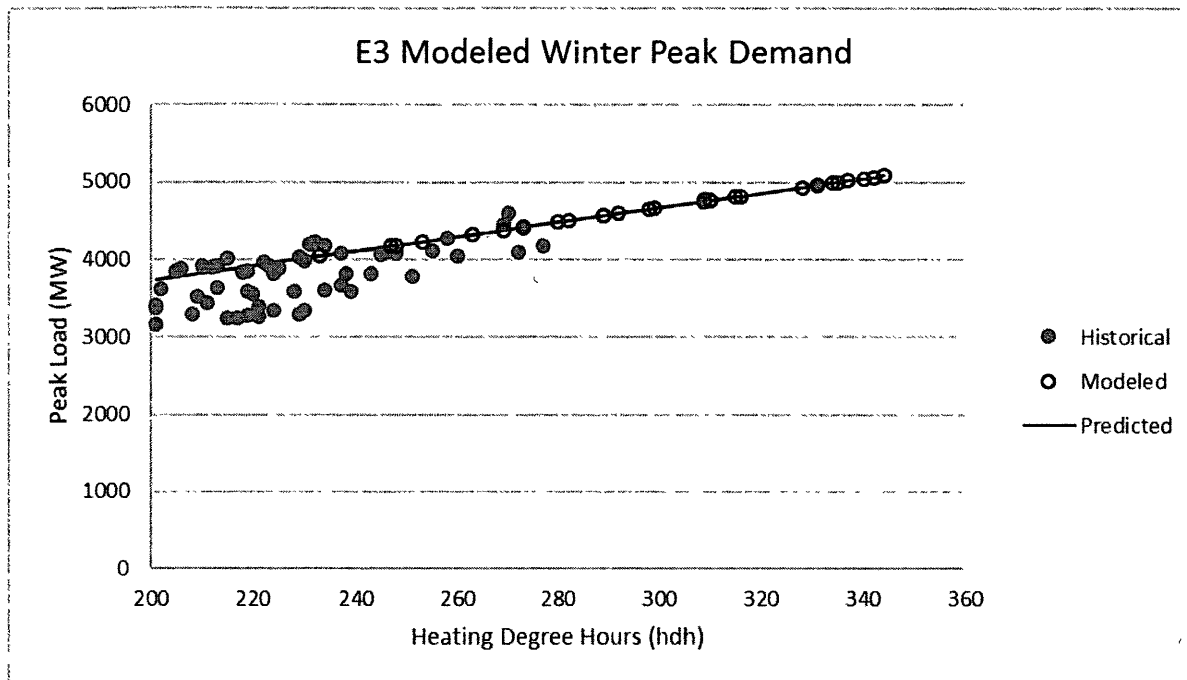
1 A. I estimate that SCE&G winter variability is 425 MW, as compared to SCE&G's
2 estimate of 542 MW. I estimated the variability using a corrected version of SCE&G's
3 regression data set. The most significant correction I made was to remove days that had
4 relative low temperatures. In the 27 years of historical winter peak data that SCE&G
5 provided, the lowest heating degree hour ("hdh") was 233. Hdh are the sum of the
6 difference between a day's hourly temperatures and a base temperature such as 60 degrees.
7 The colder the day, the larger the hdh. I, therefore, excluded all days with hdh at or below
8 200 from the dataset, as such moderate days would have little chance of being a peak winter
9 day. By doing this, the remaining data produced a regression model that gave a better
10 representation of peak electricity demand on winter peak days, and also revealed a more
11 logical linear relationship with hdh, rather than the quadratic relationship that SCE&G
12 obtained with the overly large dataset.

13 Put another way, SCE&G created a model to estimate daily peak load for any day
14 in the winter. The response of customers to changes in hdh at moderate levels is likely not
15 the same as their response at higher hdh levels. This is probably why the SCE&G model
16 has the curved shape. It is trying to fit two different response shapes. By reducing the data
17 set to exclude those moderate hdh days, my model specification is not affected by the
18 moderate days, and the curved shape is rejected for my data set --- which shows that the
19 curved response shape is not fundamental to customer response at high hdh levels.

20 The figure below shows the historical data that I used in my analysis, as well as the
21 predicted peak loads based on hdh. The round circles are the predicted peak loads for 2016,
22 at the peak day hdh observed over the last 27 years. The predicted peak would vary by

month, so I have assumed January peaks for the figure. Note that the January assumption does not affect the calculation of winter demand-side risk.

Figure 3: E3 Modeled Winter Peak Demand using Historical Weather



SCE&G defined demand-side risk as the difference between the modeled maximum peak demand and average peak demand using the 27 years of peak hdd. The table below compares SCE&G's values used in their 2017 Reserve Margin study, and the results from my regression model. The lower deviation of 425 MW is the value used in my Reserve Margin calculation earlier in this testimony.

Table 3: Winter Demand Side Risk

MW Peak Demand - Winter				
	Maximum	Normal	Deviation	%Deviation
SCE&G JML-2, Table 1	5172	4630	542	11.7%
E3	5087	4662	425	9.1%

Table 4: E3 Regression Model Specifications

SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.960166241							
R Square	0.921919211							
Adjusted R Square	0.891950135							
Standard Error	118.9069773							
Observations	56							
ANOVA								
	df	SS	MS	F	Significance F			
Regression	7	8180115.389	1168587.913	96.42585561	4.61588E-26			
Residual	49	692804.5932	14138.86925					
Total	56	8872919.982						
	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	1747.325757	153.9953487	11.34661386	2.57753E-15	1437.860518	2056.790996	1437.860518	2056.790996
ihol	-647.1513228	123.0564432	-5.258979586	3.1645E-06	-894.4425039	-399.8601417	-894.4425039	-399.8601417
wkend	-436.1093908	35.3924265	-12.32211052	1.26743E-16	-507.2331347	-364.9856469	-507.2331347	-364.9856469
hdh	9.390656604	0.640992562	14.65018031	#NUM!	8.102533825	10.67877938	8.102533825	10.67877938
Jan	109.0530828	47.81469373	2.280744146	0.026949729	12.96585833	205.1403073	12.96585833	205.1403073
Feb	154.3791379	49.20292825	3.137600614	0.002881245	55.50215169	253.2561241	55.50215169	253.2561241
Nov	-141.8875	64.24746114	-2.208453027	0.031921619	-270.997607	-12.77739305	-270.997607	-12.77739305

Q. IF YOUR LOWER WINTER RESERVE MARGIN VALUES WERE USED IN SCE&G'S IRP PROCESS, WOULD SUMMER CAPACITY NEEDS SURPASS WINTER CAPACITY NEEDS IN SOME YEARS AND THEREBY RESULT IN AVOIDED CAPACITY VALUE FOR SUMMER-FOCUSED RESOURCES LIKE SOLAR?

A. Yes, but additional corrections should be applied to the load and resource balance table to properly reflect the difference in summer and winter capacity needs. The current table would suggest that six (6) in fifteen (15) years would benefit from summer capacity. That is to say, in six (6) of the fifteen (15) years the winter reserve percentage (line 15 in Exhibit JML-1) is more than 5% greater than the summer reserve percentage (I do not count years with baseload additions or seasonal capacity purchases). The 5% "rule" is based on the winter reserve margin requirement being 4.9% higher than the summer reserve margin

requirement. For example, if the winter reserve margin percentage in 2025 were 20%, and the summer percentage was 18%, there is only a 2% difference, and winter capacity needs would be binding over summer needs. Put another way, my winter reserve margin threshold is 18.4% and my summer reserve margin threshold is 13.4%. At 20% in the winter, there is 1.6% capacity above the threshold (20% - 18.4%). At 18% in the summer, there is 4.6% capacity above the threshold (18% - 13.4%). Since 1.6% is smaller than 4.6%, winter is the constrained season.

Table 5: Seasonal Reserve Margin Difference from Exhibit JML-1

	Winter reserves in excess of summer reserves	Note
2018	6.0%	Baseload and Firm Purchase
2019	1.4%	Firm Purchase
2020	0.6%	Firm Purchase
2021	~~3.1%~~ 2.1%	Firm Purchase
2022	4.5%	Firm Purchase
2023	12.9%	Baseload added
2024	3.9%	
2025	4.3%	
2026	4.7%	
2027	5.0%	
2028	5.2%	
2029	5.4%	
2030	5.4%	
2031	7.2%	
2032	5.6%	

Q. WHAT CHANGES ARE NEEDED FOR THE LOAD AND RESOURCE TABLE, AND HOW WOULD THAT AFFECT THE VALUE OF SUMMER CAPACITY?

A. In order to properly value summer and winter capacity, it is important to remove any unintended bias between summer and winter values. Recall that SCE&G's method of

deriving the reserve margin threshold is to add up the extra capacity requirements from three components: 1) VACAR operating reserves, 2) demand-side risk, and 3) supply-side risk. The demand-side risk is the difference between the average annual peak and the maximum annual peak based on 27 recent years of data. It is therefore logical that the reserve margin threshold would be applied to forecasts of average annual peaks, since the risk of higher peaks is already embedded in the reserve margin threshold percentage.

The problem is that the load forecasts in the load and resource table (Exhibit JML-1) appear to be higher than any reasonable expectation of average peak, and moreover deviate more in the winter than the summer, which would be introducing a bias toward making winter the constrained capacity season. Table 6 shows that the gross territorial peak values in 2018 in the SCE&G load and resource table are higher than what normal loads should be given typical 1% per year growth rates since 2016. More importantly, the difference in MW is greater for winter than summer, which makes the winter appear relatively more capacity constrained than the summer.

Table 6: Potential Bias of Seasonal Peak Demands in SCE&G 2018 IRP (MW)

		Summer	Winter	Difference
1	Gross Territorial Peak from JML-1 for 2018	5077	5024	
2	Normal 2016 Peak from JML-2, table 1	4744	4630	
3	Assumed growth from 2016 to 2018	2%	2%	
4	Normal 2018 consistent with JML-2, table 1	4839	4723	
5	Difference (L1 - L4)	238	301	63

While the 63 MW bias appears small, if we apply these corrections to the SCE&G load and resource table by subtracting the seasonal differences shown in line 5 of Table 6 then summer becomes the constraining season in nine (9) of the fifteen (15) forecast years. That is a 50% increase from the six (6) out of fifteen (15) years when SCE&G's

uncorrected load and resource table is used. This is shown in Table 7, which excludes winter short term purchases and the 2023 addition of 540 MW of baseload capacity.

Table 7: Seasonal Reserve Margin Difference with Correction to Average Peak

	Winter reserves in excess of summer reserves	Note
2018	8.1%	Baseload added
2019	2.1%	
2020	1.9%	
2021	~~2.9%~~ 1.9%	
2022	3.4%	
2023	4.6%	
2024	5.5%	
2025	5.8%	
2026	6.2%	
2027	6.5%	
2028	6.6%	
2029	6.8%	
2030	6.8%	
2031	8.6%	
2032	7.0%	

Q. DO YOU BELIEVE THAT YOUR CHANGES ABOVE PROVIDE AN ACCURATE REPRESENTATION OF THE VALUE OF SOLAR CAPACITY?

A. While I believe that my changes provide a better indication of the value of solar capacity, I suspect that there are other changes that should also be applied. While the corrections that I present are relatively small individually, their impact on the relationship between winter and summer capacity need highlights the sensitive nature of this problem. Essentially a new dimension has been added into the evaluation of peak capacity and avoided capacity costs. Because of the effect of solar on summer versus winter peaks, the

1 difference in summer versus winter capacity needs becomes critical to evaluate solar, and
2 I believe it has not received sufficient exploration in this Docket.

3 **Q. IN YOUR OPINION, ARE SCE&G'S AVOIDED CAPACITY COSTS**
4 **APPROPRIATE?**

5 **A.** No. SCE&G bases its assertion of zero avoided capacity cost for solar projects on
6 SCE&G being constrained by winter capacity needs, and unaided by summer capacity
7 reductions. This is a substantial change from the methodology and inputs used by SCE&G
8 to calculate prior PR-1 and PR-2 rates, and relies upon assumptions and studies conducted
9 in the 2018 IRP that have not been fully reviewed, vetted and/or approved by the
10 Commission. Given the large change in SCE&G's position, and the uncertainty over the
11 accuracy of its new position, I recommend that SCE&G's position of zero avoided capacity
12 costs be rejected at this time.

13 **Q. GIVEN THE PROBLEMS WITH SCE&G'S ANALYSIS, WHAT DO YOU**
14 **RECOMMEND THE COMMISSION ADOPT FOR PR-2 CAPACITY VALUE?**

15 **A.** I recommend that the PR-2 capacity value be set at 19.5% of the avoided cost of
16 per kW from a 100 MW change to SCE&G's base resource plan that excludes any non-
17 committed future resources and reflects any planned plant retirements of firm capacity.
18 Including 19.5% of the avoided capacity value is based on SCE&G's solar analysis that
19 found that a 100 MW increment of new solar would reduce summer peak demand by about
20 19.5 MW (Exhibit JML-4, p. 6). For example, in Docket No. 2016-2-E, SCE&G estimated
21 the long run avoided capacity cost for a 100 MW change to be \$21.34/kW-yr (Lynch direct
22 testimony, p. 15). Applying the 19.5% factor would have resulted in an avoided capacity
23 cost for solar of \$4.16/kW-yr.

1 Unfortunately, SCE&G has not provided a long-run avoided capacity cost in this
2 Docket. ORS attempted to acquire a capacity cost estimate from SCE&G, but SCE&G
3 declined.

4 Because of the time constraints and the lack of an avoided capacity cost calculation
5 by SCE&G in this Docket, I was unable to produce an independent estimate of avoided
6 capacity costs for a 100 MW change in supply. I recommend that SCE&G be required to
7 provide an estimate of long-run avoided capacity cost and the calculation for the long-run
8 avoided capacity costs. In addition, ORS and other parties should be allowed to review
9 and provide comment to the Commission based on SCE&G's estimate and calculation.
10 Alternatively, I recommend that the current capacity value be maintained for both PR-1
11 and PR-2 until a better capacity value can be provided in the next rate update.

12 **Q. DO YOU HAVE AN OPINION ON SCE&G'S POSITION OF NOT PROVIDING A**
13 **STANDARD RATE OFFER FOR NON-SOLAR RESOURCES?**

14 A. Yes. Despite the lack of ^{uptake}~~update~~ of the PR-2 rate by non-solar resources, I believe
15 that SCE&G should continue to provide a standard published rate for such resources. The
16 lack of a published rate would increase the uncertainty and engagement costs for new
17 resources. The need to commence a negotiation on compensation terms would increase
18 project lead times and costs for the developers, which could be a significant barrier for such
19 small projects.

20 **Q. PLEASE DESCRIBE CHANGES TO SCE&G'S FILED TOTAL VALUE OF NEM**
21 **DISTRIBUTED ENERGY RESOURCES.**

22 A. As required by Commission Order No. 2015-194, SCE&G must calculate 11
23 components of value for NEM Distributed Energy Resources ("DERs"). In Docket No.

2017-2-E, SCE&G calculated these 11 components of value; in Order No. 2017-246, the Commission determined the values SCE&G calculated complied with the NEM Methodology as approved by the Commission in Order No. 2015-194. On page 27 of witness Lynch's direct testimony, SCE&G reports the updated values for these same 11 components. Table 8 below summarizes the values as approved in Order No. 2017-246 and as filed in the current Docket. The significant changes are in the Avoided Energy Costs and Avoided Capacity Costs line items.

Table 8. Value of NEM Distributed Energy Resources (\$/kWh): 2017 Approved and 2018 Filed (Lynch pp. 26,27)

	Order No. 2017-246: IRP Planning Horizon (15-yr Levelized)	Docket No. 2018-2-E IRP Planning Horizon (15-yr Levelized)	Components
1	\$.03199	\$.03014	Avoided Energy Costs
2	\$.00172	\$0	Avoided Capacity Costs
3	\$0	\$0	Ancillary Services
4	\$0	\$0	T&D Capacity
5	\$.00004	\$.00004	Avoided Criteria Pollutants
6	\$0	\$0	Avoided CO ₂ Emission Cost
7	\$0	\$0	Fuel Hedge
8	\$0	\$0	Utility Integration & Interconnection Costs
9	\$0	\$0	Utility Administration Costs
10	\$0	\$0	Environmental Costs
11	\$.03375	\$.03018	Subtotal
12	\$.00276	\$.00246	Line Losses @ 0.9245
13	\$.03651	\$.03264	Total Value of NEM Distributed Energy Resources

1 **Q. WHAT CAUSED THE DIFFERENCES IN AVOIDED ENERGY AND AVOIDED**
2 **CAPACITY COSTS FOR NEM DISTRIBUTED ENERGY RESOURCES?**

3 **A.** As described in witness Lynch's Direct Testimony, SCE&G bases its NEM DERs
4 avoided energy and avoided capacity costs on the PURPA avoided cost values. The
5 avoided energy costs are adjusted to remove criteria pollutants, which are accounted for
6 separately in the "Avoided Criteria Pollutants" line item. The PURPA avoided energy cost
7 decreased from last year, leading to a reduction in the NEM DERs avoided energy cost.
8 Similarly, this year SCE&G claimed zero value for PURPA avoided capacity cost, which
9 led to a zero value for the corresponding NEM DERs avoided capacity cost.

10 **Q. ARE SCE&G's REASONS FOR WHY IT HAS ZERO VALUE FOR 7 OF THE**
11 **OTHER COMPONENTS OF THE NEM DISTRIBUTED ENERGY RESOURCES**
12 **TOTAL VALUE STACK REASONABLE?**

13 **A.** Yes. SCE&G is following the methodology approved by the Commission in Order
14 No. 2015-194 in evaluating the value of each component of the NEM DERs Total Value
15 stack. Regarding T&D Capacity, it should be noted that some jurisdictions recognize the
16 value NEM resources can provide in deferring T&D investments and therefore attribute
17 capacity value to resources like solar. SCE&G's practice of designing transmission and
18 distribution circuits to assume DER is not generating due to weather factors or because
19 DER resources are off line does follow the Commission approved methodology, but it is a
20 conservative approach. Regarding avoided CO₂ emissions, while some jurisdictions
21 recognize value in avoided CO₂ Emissions, Commission Order No. 2015-194 directs
22 SCE&G to use zero monetary value for CO₂ "until state or federal laws or regulations result

1 in an avoidable cost on Utility systems for these emissions.” (PSC Order No. 2015-194, p.
2 9)

3 **Q. IN YOUR OPINION, ARE SCE&G’S VALUE OF NEM DISTRIBUTED ENERGY**
4 **RESOURCES COSTS APPROPRIATE?**

5 **A.** Excepting the Avoided Capacity Cost component, the filed SCE&G Value of NEM
6 Distributed Energy Resources components are conservative, but appropriate. The Avoided
7 Capacity Cost component is based on the PURPA Avoided Capacity Cost values, and I
8 have previously discussed why I find the filed PURPA Avoided Capacity Cost values
9 inappropriate. Should the Commission reject the Company’s proposed Avoided Capacity
10 Cost values, the Total Value of NEM Distributed Energy Resources would be impacted.

11 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

12 **A.** Yes.

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[PURSUANT TO PREVIOUS INSTRUCTION, THE
PREFILED SURREBUTTAL TESTIMONY OF BRIAN K.
HORII FOLLOWS AT PGS 597-613]

THE OFFICE OF REGULATORY STAFF
SURREBUTTAL TESTIMONY & EXHIBIT
OF
BRIAN HORII
APRIL 4, 2018



DOCKET NO. 2018-2-E

**Annual Review of Base Rates for Fuel Costs for South
Carolina Electric & Gas Company**

SURREBUTTAL TESTIMONY AND EXHIBIT

OF

BRIAN HORII

ON BEHALF OF THE

SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-2-E

IN RE: ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS FOR

SOUTH CAROLINA ELECTRIC & GAS COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Brian Horii. My business address is 101 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3").

Q. DID YOU FILE DIRECT TESTIMONY AND AN EXHIBIT RELATED TO THIS PROCEEDING?

A. Yes. I filed direct testimony and an exhibit with the Public Service Commission of South Carolina ("Commission") on March 23, 2018.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My surrebuttal testimony addresses the rebuttal testimony of South Carolina Electric and Gas Company's ("SCE&G" or "Company") witness Lynch regarding SCE&G's forecast need for winter capacity and a flaw within the regression analysis conducted by SCE&G.

1 **Q. WERE YOU ABLE TO VERIFY THE ANALYSIS CONTAINED IN SCE&G'S**
2 **REBUTTAL TESTIMONY FILED ON MARCH 29, 2018?**

3 **A.** No. The analysis contained in witness Lynch's rebuttal testimony required the
4 South Carolina Office of Regulatory Staff ("ORS") to request additional information from
5 SCE&G. On March 30, 2018, ORS issued a Utility Services Request #6 (Surrebuttal
6 Exhibit BKH-1). ORS received the requested information on April 3, 2018, which did not
7 allow me sufficient time to thoroughly review or analyze.

8 **Q. HAS SCE&G PROVIDED EVIDENCE OF THE ZERO POINT FOR SOLAR**
9 **CAPACITY AS STATED ON PAGE 3 OF WITNESS LYNCH'S REBUTTAL**
10 **TESTIMONY?**

11 **A.** No. While witness Lynch cites to the size of the interconnection queue, the size of
12 the queue is irrelevant. Under the Public Utility Regulatory Policies Act of 1978
13 ("PURPA") methodology, the capacity value is based on the next 100 megawatts ("MW")
14 of capacity incremental to current or already contracted resources. SCE&G further
15 contends that "with 865 MW of solar under contract ... solar has already reached this zero
16 point for capacity." (Lynch Rebuttal, p. 3) However, SCE&G provides no specific
17 evidence to support that contention. Perhaps SCE&G is relying upon its position that solar
18 provides no capacity value because it provides no winter peak reductions. However, as I
19 show throughout my direct and surrebuttal testimony, SCE&G has not adequately proven
20 that point, and therefore has not proven that the capacity zero point has been reached for
21 solar.

1 **Q. SCE&G REJECTS YOUR CLAIM THAT THERE ARE FLAWS AND**
2 **INCONSISTENCIES IN THEIR 2017 RESERVE MARGIN STUDY. CAN YOU**
3 **PROVIDE MORE DETAILS TO SUPPORT YOUR CLAIM?**

4 **A.** Yes. I had difficulty in verifying the results listed by SCE&G in Exhibit JML-2
5 2017 Reserve Margin Study (“Study”) because SCE&G did not only use the data contained
6 in its Study. SCE&G witness Lynch’s direct testimony Exhibit JML-2 uses regression
7 equations (page 13) to create the graph of winter peak demand response to temperature
8 (page 4) and to calculate the amount of winter peak deviations contained in Table 1 (page
9 5). I found the regression equations use different temperature variables than those shown
10 in the graph on page 4. It is not possible to recreate the graph on page 4 or Table 1 using
11 the regression equation and data provided by SCE&G in Exhibit JML-2. Moreover, one
12 cannot draw conclusions or insights from the graphs on page 3, because those also fail to
13 match the regression equation that SCE&G presented.

14 Only through a phone conversation with SCE&G on March 21, 2018, two (2) days
15 prior to the ORS testimony filing date, did I learn of the data inconsistency that gives the
16 false impression of temperature response implied by the regression equations. SCE&G
17 presented regression equations with the variable labeled “hdh” which implies the data is
18 the well understood and commonly used Heating Degree Hour temperature metric. In
19 addition, on page 2 of Exhibit JML-2, SCE&G even states “two regression equations were
20 estimated: one for summer relating daily summer peak demands to cooling degree hours
21 and one for winter relating daily winter peak demands to heating degree hours.”

22 However, the “hdh” variable used by SCE&G is actually a transformed variable
23 that, while related to hdh is not heating degree hours. SCE&G informed me during the

1 phone conversation on March 21, 2018, the Company subtracted 109.341 from the actual
2 hdh to create the value used in its regression modeling and provided to ORS. Due to this
3 variation in method to calculate hdh, which is not disclosed in witness Lynch's testimony
4 or revealed in the Study, I was unable to accurately evaluate SCE&G's Study results.

5 **Q. DO YOU AGREE WITH SCE&G'S CLAIM ON PAGE 7 OF WITNESS LYNCH'S**
6 **REBUTTAL TESTIMONY THAT COMPARING SUMMER AND WINTER**
7 **GROWTH RATES IS A WAY TO DEMONSTRATE THERE IS NO BIAS**
8 **TOWARDS A LARGER WINTER PEAK FORECAST?**

9 **A.** No. I show on page 19 of my direct testimony, the first year in the SCE&G forecast
10 (2018) is biased to reduce the gap between summer and winter peak demand and thereby
11 make the argument for the need for winter capacity look more compelling. Any growth
12 rates applied to the erroneous first year values would simply continue the bias throughout
13 the forecast.

14 **Q. DO YOU AGREE WITH SCE&G'S ASSERTIONS ON PAGE 9 OF WITNESS**
15 **LYNCH'S REBUTTAL TESTIMONY REGARDING THE HEATING ASPECTS**
16 **OF HEAT PUMPS AND SPACE HEATERS SUCH THAT IT CHANGES YOUR**
17 **VIEW ON THE UPWARD SLOPE OF WINTER PEAK DEMAND?**

18 **A.** No. SCE&G's explanation fits with my statement that there are two (2) types of
19 heating response relationships displayed in the daily winter peak data. On more moderate
20 days, the rise in demand with colder temperatures is moderate because the heat pumps can
21 operate in the efficient range without the need for the supplemental heat strips. During
22 cold temperatures, however, heat strips and other space heaters are used, so the rise in peak
23 demand with colder temperatures is larger. At some point, one would expect even those

1 heat strips and space heaters to begin to reach usage saturation, so further heating load
2 would tail off.

3 This strengthens my argument that all winter days should not be used in the
4 regression modeling. By taking SCE&G's approach, one is forcing a single regression
5 equation to try to fit two different types of temperature response.

6 **Q. DO YOU AGREE WITH SCE&G'S CLAIM ON PAGE 11 OF WITNESS LYNCH'S**
7 **REBUTTAL TESTIMONY THAT, BECAUSE A LINEAR EQUATION SHOULD**
8 **NOT PRODUCE SIGNIFICANTLY DIFFERENT RESULTS THAN THE**
9 **QUADRATIC EQUATION, IT IS SATISFACTORY TO USE SCE&G'S**
10 **QUADRATIC EQUATION?**

11 **A.** No. While the difference in the winter reserve margin due to correcting SCE&G's
12 regression model may appear to be relatively small in isolation, when combined with other
13 corrections to SCE&G's approach, the total impact is a rejection of their position that solar
14 provides no capacity value.

15 **Q. DO YOU AGREE WITH SCE&G'S ASSERTIONS ON PAGES 13-14 OF WITNESS**
16 **LYNCH'S REBUTTAL TESTIMONY THAT YOUR CALCULATION OF**
17 **WINTER DEMAND SIDE RISK IS INCORRECT, AND THAT WITH HIS**
18 **CORRECTIONS, YOUR RESULTS WOULD BE COMPARABLE TO SCE&G'S**
19 **ESTIMATE OF WINTER DEMAND SIDE RISK?**

20 **A.** No. This point highlights the difficulty in addressing SCE&G's substantial change
21 in approach in its resource plan filed in this docket (Exhibit JML-1). SCE&G makes two
22 (2) changes to my estimation of demand side risk. First, they use February as the peak
23 month instead of January. That change does not actually affect my estimate of winter

1 demand side risk, as both my estimate of winter maximum peak and average peak change
2 by the same MW if the peak were to occur in February. Since the demand side risk is the
3 difference between maximum and average peak, increasing both by the same amount
4 results in no change in risk

5 Second, SCE&G calculates the average peak using a mix of months, whereas my
6 method uses the same month for calculating all peak values. Whether this change is
7 appropriate depends upon how SCE&G performs its Integrated Resource Plan ("IRP")
8 forecasts. In other state jurisdictions, there is a strong direct link between how utility
9 forecasts are prepared in the IRP and how risk is applied on top of that forecast. The basic
10 question is how much risk is recognized in the IRP forecast, and how much additional risk
11 needs to be reflected in the reserve margin. While SCE&G did provide some information
12 on their IRP forecasting process in response to the ORS Utility Service Request #6, it
13 would require more time and additional detailed information in order to determine whether
14 SCE&G's second adjustment to my demand side risk is correct.

15 If SCE&G's second change were appropriate, then their change of my demand side
16 risk from 9.1% to 10.2% would be correct. However, that estimate is still 1.5% lower than
17 the 11.7% value from their reserve margin study, and I would consider the 10.2% to be
18 closer, but not comparable, to the SCE&G estimate of winter demand side risk.

19 **Q. IF SCE&G'S ASSERTION IS CORRECT THAT YOUR WINTER DEVIATION**
20 **SHOULD HAVE BEEN HIGHER, WOULD THAT CHANGE YOUR POSITION?**

21 **A.** No. Such a change might change the number of years during which summer would
22 be the binding capacity constraint, but it would not change the fact there will be some
23 number of years over the next fifteen (15) years where summer capacity would be the driver

1 of capacity need. This debate over regression models and reserve margin methodologies
2 highlights that this is a complex issue that depends upon the relationship between summer
3 and winter capacity needs. This topic area has not received careful scrutiny in South
4 Carolina, nor in North America in general.

5 **Q. DO YOU AGREE WITH SCE&G'S ASSERTION ON PAGE 15 OF WITNESS**
6 **LYNCH'S REBUTTAL TESTIMONY THAT ITS PEAK DEMAND**
7 **FORECASTING IS REASONABLE BASED ON A COMPARISON OF**
8 **HISTORICAL FORECASTS AND ACTUAL PEAKS?**

9 **A.** No. In fact, the analysis provided by SCE&G in pages 15 and 16 of witness Lynch's
10 rebuttal raises more doubt over the forecasts that SCE&G has used in its 2018 IRP. Over
11 the past four (4) years, SCE&G forecast average winter growth of 36.25 MW per year.¹
12 The highest growth in any of those years was 106 MW between 2014 and 2015.² Yet for
13 2018 in the IRP, SCE&G forecasts a gross territorial peak of 5024 MW for winter 2018,
14 which is 388 MW higher than the forecast for winter 2017³ and 256 MW higher than the
15 actual 2017 winter peak.⁴

16 **Q. IS SCE&G'S STATEMENT ON PAGE 19 OF WITNESS LYNCH'S REBUTTAL**
17 **TESTIMONY THAT "PJM HAS A 16% SUMMER RESERVE MARGIN AND A**
18 **27% WINTER RESERVE MARGIN" PERTINANT TO THIS DOCKET?**

19 **A.** No, and I believe that statement is misleading because it implies that it is
20 appropriate for SCE&G to have a higher winter planning reserve margin than summer

¹ 36.25 MW = (4,636 MW in 2017 minus 4,491 MW in 2013) divided by four years.

² 106 MW = 4,602 MW in 2015 minus 4,496 MW in 2014.

³ 388 MW = 5,024 MW (2018 IRP) minus 4,636 MW (forecast 2017).

⁴ 256 MW = 5,024 MW (2018 IRP) minus 4,768 MW (actual 2017).

1 planning reserve margin because PJM has that as well. PJM does not have a higher
2 planning reserve margin in the winter. SCE&G fails to point out that it is quoting a 16%
3 summer Installed Reserve Margin (“IRM”) and a 27% Winter Weekly Reserve Target
4 (“WWRT”). While they both have “reserve” margin in their description, they are not
5 comparable.

6 The summer IRM is equivalent to the planning reserve margins that we have been
7 debating in this docket. PJM bases its IRM on the common 1 day in 10 years Loss of Load
8 Expectation (“LOLE”) criteria. The IRM is valid for determining amounts of installed
9 capacity that are needed to provide adequate reliability.

10 The WWRT, on the other hand, is not used to determine the amount of capacity
11 that needs to be installed. Rather, it is used as a metric for determining when units can go
12 down for maintenance outages in the winter. The WWRT calculation begins with the
13 resources identified as needed using the summer IRM, and then simulates additional
14 planned maintenance outages of these units in the winter until they increase the annual
15 LOLE risk by one (1) event in one million years. The available reserves from the units that
16 were not put in maintenance outage mode comprise the WWRT. In other words, the
17 WWRT starts with the capacity that is determined to be needed because of the summer
18 capacity need, and then finds how much that capacity can be reduced while still
19 maintaining annual reliability. The 27% WWRT represents less capacity need than the
20 15% summer IRM.

21 PJM is undertaking an evaluation of winter IRM, but I do not believe that study has
22 been completed yet. In the interim, however, it is incorrect to think that the 27% WWRT
23 represents what a winter planning reserve margin would be for PJM.

1 **Q. DO YOU AGREE WITH SCE&G'S CLAIM ON PAGE 22 OF WITNESS LYNCH'S**
2 **REBUTTAL TESTIMONY THAT THE LOSS OF LOAD EXPECTATION**
3 **MODEL USED BY THE ELECTRIC RELIABILITY COUNCIL OF TEXAS**
4 **("ERCOT") "DOES NOT ALWAYS GIVE A REASONABLE ANSWER"**
5 **BECAUSE THE MODEL RESULTS IN A LOWER RESERVE MARGIN?**

6 **A.** No. SCE&G's claim is not supported by their own example. The ERCOT example
7 is a case where the balance of the cost of adding new capacity and the estimated value of
8 added reliability to customers justifies a lower reserve margin than that which is estimated
9 using the 1 day in 10-year criteria. The fact that the SERVVM model estimated a lower
10 reserve margin than the 1 day in 10-year criteria does not prove that the SERVVM model or
11 methodology are incorrect.

12 **Q. DO YOU BELIEVE THAT HISTORY JUSTIFIES SCE&G'S USE OF THE**
13 **"COMPONENT METHOD" FOR THIS DOCKET TO DETERMINE ITS**
14 **RESERVE MARGIN, AS STATED ON PAGE 8 OF WITNESS LYNCH'S**
15 **REBUTTAL TESTIMONY?**

16 **A.** No. The SCE&G method may have been adequate in the past. Indeed, in looking
17 at the reserve margin results from the 2016 IRP, the planning reserve margin from the
18 method produced results that were consistent with the range of reserve margins that I have
19 seen for other utilities and other jurisdictions. However, in this docket, we are reliant upon
20 the reserve margin methodology to determine the difference in reserve margin
21 requirements between the summer and winter season. For this purpose, it is unclear if the
22 component methodology is appropriate. My research indicates that LOLE, Loss of Load
23 Probability ("LOLP"), or related Expected Unserved Energy are commonly accepted

methodologies in the industry. I am not aware of the component method being used elsewhere. I believe that a large change in treatment for valuing PR-2 capacity should not be based on the component method, but should only be considered after the seasonal capacity question is evaluated using industry standard methods.

Q. IS SCE&G'S CLAIM ON PAGE 5 OF WITNESS LYNCH'S REBUTTAL TESTIMONY THAT WINTER CAPACITY NEED IS GREATER THAN SUMMER CAPACITY NEED IN ALL YEARS OF THE PLANNING HORIZON CONSISTENT WITH THE 2018 IRP LOAD AND RESOURCES FORECAST THAT SCE&G PROVIDED AS EXHIBIT JML-1?

A. No. SCE&G's tables on page 5 are not consistent with the IRP forecast and load resource plan supplied by SCE&G as Exhibit JML-1. To check SCE&G's tables, I reconstructed them using the data in Exhibit JML-1, which allowed me to identify SCE&G's error. Shown below are examples of my IRP-based reconstruction calculations for 2019 and 2028.

Table 1: E3 Reconstruction of 2019 Difference in Winter-Summer Need

	2019 Reconstruction	Summer	Winter	Source
1	Peak Demand MW	5111	5071	JML-1, L3
2	Reserve Margin	14%	18%	
3	Total Capacity Need	5827	5984	(L1*(1+L2))
4	Less DSM	-275	-223	JML-1, L6
5	Less Solar	-162	0	JML-1, L5 + L7
6	Less Existing Capacity 2018 (S)	-5278	-5278	JML-1, L4
7	Less extra Incremental Winter Capacity (2018)		-186	JML-1, L4 W-S
8	Net Incremental Need	112	297	(Sum L3:L7)
9	Difference in Winter-Summer Need		185	(L8 W-S)

Table 2: E3 Reconstruction of 2028 Difference in Winter-Summer Need

	2028 Reconstruction	Summer	Winter	Source
1	Peak Demand MW	5750	5473	JML-1, L3
2	Reserve Margin	14%	18%	
3	Total Capacity Need	6555	6458	(L1*(1+L2))
4	Less DSM	-286	-332	JML-1, L6
5	Less Solar	-303	0	JML-1, L5 + L7
6	Less Existing Capacity 2018 (S)	-5278	-5278	JML-1, L4
7	Less extra Incremental Winter Capacity (2018)		-186	JML-1, L4 W-S
8	Net Incremental Need	688	662	(Sum L3:L7)
9	Difference in Winter-Summer Need		-26	(L8 W-S)

My Table 1 results match the SCE&G table shown at the top of page 5 of the rebuttal testimony of SCE&G witness Lynch. Table 2 for 2028 matches the SCE&G summer net incremental need, but the winter net incremental need and the Difference in Winter-Summer Need are 100 MW lower than SCE&G's estimate of 762 MW and 74 MW for 2028. This 100 MW difference exists for all years after 2019, and exists in both the 21% reserve margin and the 18% reserve margin scenarios. This error by SCE&G makes the winter peak look more severe and masks the fact that the summer peak would become dominant in the later years when my 18% winter reserve margin is used.

The errors in the SCE&G tables on page 5 of the rebuttal testimony are due to the Company using estimates of winter Demand Side Management ("DSM") reductions after 2020 that are 100 MW lower than the values presented in SCE&G's 2018 IRP (Exhibit JML-1). SCE&G did not provide a reason for departing from the IRP values, and even if there were a reason, such a change would exacerbate my concerns over assuming zero capacity for PR-2 based on SCE&G's IRP and reserve margin analyses.

My IRP-based reconstructed values for all years are shown in the following tables in Columns A through D. Column E reproduces the difference values from SCE&G's

rebuttal testimony, and Column F shows SCE&G's difference calculation minus my IRP-based results.

Table 3: IRP-Based Reconstruction of Net Incremental Capacity Need and Seasonal Differences (21% Case)

Smr: 14.0% Wtr: 21.0%					
A	B	C	D	E	F
Year	IRP-based Summer Net Incremental Need	IRP-based Winter Net Incremental Need	IRP-based Net Incremental Need Difference	SCE&G Difference (Lynch rebuttal, p. 5)	SCE&G minus IRP-based
2019	112	449	337	337	0
2020	48	404	355	455	100
2021	131	486	355	455	100
2022	250	536	285	385	100
2023	341	570	229	329	100
2024	409	620	210	310	100
2025	486	677	191	291	100
2026	561	729	168	268	100
2027	627	778	151	251	100
2028	688	826	138	238	100
2029	745	870	125	225	100
2030	797	921	124	224	100
2031	854	971	117	217	100
2032	909	1022	113	213	100

Table 4: IRP-Based Reconstruction of Net Incremental Capacity Need and Seasonal Differences (18% Case)

Smr: 14.0% Wtr: 18.0%					
A	B	C	D	E	F
Year	IRP-based Summer Net Incremental Need	IRP-based Winter Net Incremental Need	IRP-based Net Incremental Need Difference	SCE&G Difference (Lynch rebuttal, p. 5)	SCE&G minus IRP-based
2019	112	297	185	185	0
2020	48	250	202	302	100
2021	131	330	200	300	100
2022	250	379	129	229	100
2023	341	412	71	171	100
2024	409	461	51	151	100
2025	486	516	31	131	100
2026	561	567	6	106	100
2027	627	615	-12	88	100
2028	688	662	-26	74	100
2029	745	705	-41	59	100
2030	797	754	-42	58	100
2031	854	803	-51	49	100
2032	909	853	-56	44	100

Q. LOOKING AT YOUR IRP-BASED RECONSTRUCTIONS, DO YOU AGREE WITH SCE&G THAT WINTER CAPACITY NEED IS GREATER THAN SUMMER NEED IN ALL YEARS OF THE PLANNING HORIZON?

A. No. Column D of Table 4 shows that summer capacity need would exceed winter capacity need in 2027 and all subsequent years. If my corrections for the winter peak demand forecast bias were incorporated (pp. 18-20 of my Direct Testimony, and pp. 14-15 of this Surrebuttal), the result would demonstrate even more years would be designated as summer peaking.

Q. DO YOU AGREE WITH SCE&G'S ASSERTIONS ON PAGE 16 OF WITNESS LYNCH'S REBUTTAL TESTIMONY THAT THE SCE&G PEAK DEMAND

FORECASTS ARE REASONABLE WHEN YOU CONSIDER THAT “SCE&G WOULD EMPLOY ITS DEMAND RESPONSE RESOURCES ON MANY OF THESE HISTORICAL PEAK DAYS”?

A. No. The data that SCE&G used to estimate winter normal peak demand and winter demand side risk in the Study (Exhibit JML-2) was from November 2014 through March 2017. SCE&G did not call for demand response during that same time period, so it would not be possible for an analysis using that data to show reductions from demand response. Since I used a subset of that same dataset to calculate my estimate of normal seasonal loads, it would not be appropriate to compare my normal values that do not reflect demand response to a SCE&G forecast that is reduced by demand response.

Moreover, if one were to compare the SCE&G forecast net of demand response (a firm peak forecast), then the seasonal bias problem is worse than I originally estimated.

Table 5 (below) shows my original estimate of winter bias. Line 5 calculates a substantial difference between the IRP forecast (line 1) and the escalated normal value based on the reserve margin study (line 4). The Table also shows that the seasonal difference is 63 MW larger in the winter, indicating a bias toward overestimating the winter peak and therefore overestimating the need for winter capacity.

Table 5: Winter Peak Bias from Horii Direct Testimony Table 6

		Summer	Winter	Difference
1	Gross Territorial Peak from JML-1 for 2018	5077	5024	
2	Normal 2016 Peak from JML-2, table 1	4744	4630	
3	Assumed growth from 2016 to 2018	2%	2%	
4	Normal 2018 consistent with JML-2, table 1	4839	4723	
5	Difference (L1 - L4)	238	301	63

Table 6 (below) shows the same information, but replaces the Gross Territorial Peak from the IRP with the firm peak demand which is the Gross Territorial peak net of demand response. Line 5 shows that the differences within a season are far less than in my original table (Table 6 of my direct testimony and Table 5 in this surrebuttal), but the difference between seasons is almost double. This indicates that even if considering demand response makes the IRP forecast look more consistent with historical-weather-based peaks, it would not eliminate the issue of winter capacity bias, and in fact would almost double the bias that makes winter capacity appear more needed than summer capacity.

Table 6: Winter Peak Bias using Firm Peaks Net of Demand Response

		Summer	Winter	Difference
1	Firm Peak from Lynch Rebuttal, p. 16	4803	4802	
2	Normal 2016 Peak from JML-2, table 1	4744	4630	
3	Assumed growth from 2016 to 2018	2%	2%	
4	Normal 2018 consistent with JML-2, table 1	4839	4723	
5	Difference (L1 - L4)	-36	79	115

Q. HAVE YOUR RECOMMENDATIONS MADE IN YOUR DIRECT TESTIMONY CHANGED?

A. No. My recommendations remain the same:

- 1) SCE&G's position that avoided capacity cost should be set at \$0.00 should be rejected.
- 2) The PR-2 capacity value be set at 19.5% of the avoided cost per kW from a 100 MW change to SCE&G's base resource plan that excludes any non-committed future resources and reflects any planned plant retirements of firm capacity.
- 3) Require SCE&G to provide an estimate of long-run avoided capacity cost and the calculation for the long-run avoided capacity costs.

1 4) In the alternative, require the current capacity value be maintained for both PR-1 and
2 PR-2 until a better capacity value can be provided in the next rate update.

3 **Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

4 **A. Yes, it does.**

1 **MR. BATEMAN:** Mr. Chairman, Ms. Johnson and
2 Mr. Horii are available for questions from the
3 other parties and from the Commission. Thank you.

4 **CHAIRMAN WHITFIELD:** Thank you, Mr. Bateman.
5 Mr. Burgess, questions?

6 **MR. BURGESS:** We have no questions of these
7 witnesses.

8 **CHAIRMAN WHITFIELD:** Okay. Mr. Whitt, Mr.
9 Snowden?

10 **MR. WHITT:** Attorney Snowden is going to
11 question.

12 **CHAIRMAN WHITFIELD:** Yes, sir. Come forward,
13 Mr. Snowden.

14 **CROSS EXAMINATION**

15 **BY MR. SNOWDEN:**

16 **Q** Good afternoon, Mr. Horii.

17 **A** [HORII] Good afternoon.

18 **Q** Mr. Horii, what information did you review to prepare
19 your testimony for this proceeding?

20 **A** [HORII] Let's see. I reviewed the direct testimony of
21 Witness Lynch and his attached exhibits. I also sort of
22 looked at additional information that SCE&G provided as
23 part of the data requests. I also reviewed documents on
24 planning reserve margin calculations from other
25 jurisdictions, looked at information on sort of peak-

1 load forecasting. Oh, also, investigated the reserve
2 margin requirements for PJM to respond to a particular
3 issue that Witness Lynch raised in his rebuttal.

4 **Q** Okay, thank you. And when you say "information provided
5 by SCE&G," you're referring to the work papers that were
6 requested by ORS?

7 **A** [HORII] Yes, that's correct.

8 **Q** We've had a lot of semantic discussions about
9 methodology and, you know, what's methodology. Just for
10 purposes of being clear, I'm going to say "2017
11 methodology" to refer to the methodology that was used
12 to prepare the existing PR-2 rate and "new methodology"
13 as the methodology that the company is proposing now.
14 So, did you – or, rather, did ORS – request that the
15 company provide a calculation of avoided costs, based on
16 the 2017 methodology but updated inputs?

17 **A** [HORII] Well, we requested that the company provide an
18 estimate of capacity, avoided capacity costs, for a
19 basically round-the-clock resource, which would be
20 similar to the 2017 methodology.

21 **Q** Okay. And was that requested in writing, do you know?
22 Or was that –

23 **A** [HORII] That was one of – I think it was, subject to
24 check, ORS Data Request No. 4, I believe.

25 **Q** Okay. And why did you request information?

1 A [HORII] Well, in particular, I was concerned at that
2 time with their failure to produce an avoided capacity
3 cost number for non-solar PR-2 resources, so I wanted to
4 sort of have that on record, what that would be, so the
5 Commission would then have the ability to, you know,
6 perhaps reject the ORS's – not ORS's – SCE&G's position
7 in that regard, and have something on the record that
8 could be used to populate a new PR-2 rate.

9 Q Okay. Did you also think it was important to understand
10 sort of the overall impact of the methodological changes
11 that were proposed?

12 A [HORII] I think I had an understanding of the impact of
13 the methodological changes. What I didn't have an
14 understanding of is what would the capacity value have
15 been, since I think there is, you know, probably
16 substantial uncertainty over that, since the last time
17 we had that calculation the V.C. Summer plants were in
18 the capacity plan, and because many people said, "Well,
19 we'd expect that capacity value, then, to go up with the
20 elimination of those plants from the plant," yet we
21 don't have any information from the company to verify or
22 contradict that.

23 Q Okay. So the company did not provide the information
24 that was requested; is that right?

25 A [HORII] That is correct.

1 Q Okay. Yesterday, in – Dr. Lynch testified – or, do you
2 recall that Dr. Lynch testified yesterday that the
3 company had, for internal purposes, prepared some sort
4 of estimates of avoided cost sometime in the fall of
5 2017?

6 A [HORII] Are you referring to estimates of avoided
7 capacity costs or avoided energy costs?

8 Q Avoided capacity costs.

9 A [HORII] Actually, I don't recall that.

10 Q Okay, so you don't recall a discussion of internal
11 estimates of avoided capacity costs.

12 A [HORII] No. I remember lots of discussion over, you
13 know, capacity costs and their position that,
14 essentially, it's zero, so they sort of know the answer,
15 and I'm actually not familiar with how much calculation
16 they actually would have done to arrive at that versus
17 arriving at that conclusion, first, basically sort of
18 reaching the answer without sort of showing their work.

19 Q Okay. So in the documents that you reviewed, you did
20 not see the company show its work in how it got to the
21 zero capacity cost for solar?

22 A [HORII] Well, I saw how they justified, in their mind,
23 that the company is now winter peaking and that there
24 should therefore be zero value for summer capacity, and
25 that solar provides no winter capacity value and

1 therefore they make the sort of next step and say that,
2 therefore, solar provides no capacity value. And I did
3 spend a lot of time sort of, therefore, investigating
4 whether this need for winter capacity over summer
5 capacity was really valid, and that's what a lot of my
6 testimony deals with, that I think there are flaws in
7 the analysis used to come up with that position, and
8 therefore, you know, there are flaws in their position
9 of no capacity value.

10 **Q** Okay. And did you listen to Dr. Lynch's testimony
11 yesterday regarding the winter-reserve-margin issue?

12 **A** [HORII] I did.

13 **Q** All right. And do you recall Dr. Lynch testifying that
14 PJM has a 27 percent winter reserve margin as compared
15 to SCE&G's proposed 21 percent?

16 **A** [HORII] I do remember that, and there's actually I think
17 maybe a page and a half in my surrebuttal testimony that
18 addresses this, because he is correct that they do have
19 a summer value that they call reserve margin, but that
20 is an installed reserve margin. And that's really sort
21 of comparable to what we think about in this proceeding
22 as the planning reserve margin: the 14 percent number
23 and the 21 percent number that SCE&G has talked about.
24 Unfortunately, the other number, the 27 percent number,
25 is not an installed reserve margin; it's a totally

1 different metric. It's a winter weekly reserve target.
2 And although they both have "reserve" in the name,
3 they're not used for the same purpose. That winter
4 reserve target, they actually look at "What resources do
5 we actually have installed and how many of those can we
6 allow to go on maintenance outages during the winter and
7 basically still retain reliability," basically not let
8 reliability degrade by what they say in their own
9 documents is a one-day – or, one event in a million.
10 And so, you know, it's completely different usage, used
11 for setting maintenance schedules, not for adding
12 capacity, and it's a completely different sort of
13 criteria that needs to be met. There's no degradation
14 of one event in a million, as opposed to the one in ten
15 that they use for their reserve margin, the installed
16 reserve margin.

17 **Q** Okay, so you heard yesterday Dr. Lynch explain why, in
18 his view, you were wrong and that this really was an
19 apples-to-apples comparison?

20 **A** [HORII] I did, and I think it really is an apples-to-
21 oranges, you know, evidenced by PJM's own documents, and
22 even their use of a different term. I mean, it's not
23 even the same terminology they use to refer to the two
24 numbers.

25 **Q** Okay. So it's still your opinion that the company's

1 calculation of its winter reserve margin is not
2 reasonable?

3 A [HORII] That's right. I think that, you know, in the
4 past, their component method may have been adequate. It
5 gave sort of, you know, reserve margin targets that were
6 very comparable to what the industry, you know,
7 produces. In fact, they were somewhat on the lower end
8 of what we typically see from many Reserve Margin
9 Studies. But now they've sort of escalated the
10 importance of those studies, because now there's this
11 big issue of what is winter versus summer need, and
12 that's something I don't think has been, you know,
13 explored at all in depth, and that's where I think there
14 are issues with their method.

15 You know, unfortunately, because they've taken this
16 position of it's a binary position, it's almost like
17 they're saying it's winter only or summer. And, you
18 know, that's also a big change. We've heard previously
19 about this 80 percent, 20 percent winter. They moved
20 away from that. Now they say it's 100 percent winter,
21 no summer. And for them to make that big of a change, I
22 just feel there has to be, you know, nearly indisputable
23 sort of facts backing up that change and, you know,
24 backing up the studies that justify their numbers, and I
25 just don't think that's there.

1 Q And so, Mr. Horii, you heard Dr. Lynch testify this
2 morning that it was his opinion that the loss-of-load-
3 probability methodology that you would advocate, I
4 believe, was not an appropriate way of calculating a
5 reserve margin and that the company's component method
6 is a better way of doing it? Did you hear him testify
7 to that this morning?

8 A [HORII] I did hear that, yes.

9 Q Did he convince you of that?

10 A [HORII] Unfortunately, not at all. You know, while that
11 may be his opinion, you know, there's basically the rest
12 of the industry. You know, I did a study of
13 reliability, the sort of metrics for generation, you
14 know, back in the 2000s, and, you know, looked at 20
15 different jurisdictions at the time, and no one did
16 anything like the component method. Everyone did either
17 LLP, LOLE, expected unserved energy, or looked at sort
18 of losing the largest generation asset; those are sort
19 of the industry standards. And since then, it's become
20 even more sort of evolved in the way the industry looks
21 at that, with sort of this balancing of outages with
22 sort of the reliability and value to customers, and the
23 cost of adding new generation. I think that's a lot of
24 what Ms. Glick talked about. So those are really the
25 methods that are the industry standard now, and this

1 component method and its reliance on this difference
2 between a normal-weather year and a peak-weather year,
3 this 500-megawatt winter issue that Dr. Lynch talked
4 about a lot – now, that's looking at a maximum, and all
5 of these studies that the industry uses are
6 probabilistic, so they'll look at sort of this worst-
7 case event but that, you know, gets only a certain
8 amount of weight. It's not all based on that, because
9 this is a balance of risk. You know, you could have
10 that bad event happen, but, if your generators are all
11 available, you're fine; you don't have an issue. So as
12 you join a risk of load being too high and, you know,
13 generation being too low, that really drives the need
14 for capacity and you can't do this sort of simply just
15 sort of look at the max event.

16 Q And, Mr. Horii, did you hear Ms. Glick testify yesterday
17 that it would be appropriate to have independent
18 evaluation of the company's winter reserve margin?

19 A [HORII] I did.

20 Q Okay. And would you agree with that recommendation?

21 A [HORII] Well, I don't know if it necessarily needs be an
22 independent company that comes in, but I certainly would
23 support the idea that an industry-standard-more
24 computation or really robust sort of method be used.

25 Q Okay. So, Mr. Horii, you testify in your direct

1 testimony that you think the use of a solar generation
2 profile is a reasonable way to calculate avoided cost;
3 is that right?

4 A [HORII] I think that's a reasonable way to calculate
5 avoided cost for a rate that is just applied to solar
6 resources.

7 Q And that's because – well, you testified that it's an
8 improvement to use an avoided energy cost which more
9 closely tracks the avoided energy, for solar generation?

10 A [HORII] That's correct.

11 Q Okay. And so, does that assume that the solar profile
12 that's used actually matches generation, in reality?

13 A [HORII] It does. And, you know, when you come up with
14 rates that are either, you know, a single number or even
15 time-of-use averages, it's always a trade-off between
16 simplicity and accuracy. You know, ideally, what we'd
17 like to see are hourly avoided cost rates, so then the
18 exact pattern of the actual generation can sort of be
19 used to come up with a compensation. Once we start to
20 do things like averages by TOU period, then you have to
21 assume some sort of output shape to come up with that
22 average, and then there are always going to be errors
23 when you do that. But, again, a sort of simplicity
24 versus precision.

25 Q But so you would think it would be most efficient to

1 have a pricing structure that provided more compensation
2 for production during the peak hours and sort of – let
3 me step back – under which compensation or the rate were
4 proportional to the demand during the time the energy
5 was produced?

6 A [HORI] Well, I mean, what I'm – okay, I guess I should
7 clarify. You know, what I was asked to do is look at
8 whether SCE&G's method is sort of, you know, consistent
9 with past practices and with PURPA. And I think it is.
10 Now, I sort of maybe went off-track a little bit talking
11 about ideally what I'd like to see and, you know, that
12 ideal sort of framework gets away from a lot of the
13 issues, I think, that you may be thinking about with
14 different solar profiles ending up with sort of, you
15 know, different compensation, or they should end up with
16 different compensation.

17 Q Okay. Are you aware of other utilities that use solar
18 profiles to calculate avoided costs?

19 A [HORI] You know, the general practice that I'm familiar
20 with is they'll calculate avoided costs or margin of
21 cost using just sort of a standard change over all
22 hours. And the way they do that is then that avoided
23 cost that they have, those hourly numbers, are then
24 flexible. They can be applied to any kind of generation
25 shape, be it solar, be it, you know, solar-plus-storage,

1 be it energy efficiency, et cetera, but that just sort
2 of gives them more flexibility in how they use those
3 numbers.

4 I think it is common, though, to sort of take those
5 numbers and then multiply them by a solar shape, then,
6 to come up with what the compensation should be for
7 solar. So it's sort of the solar shape is applied
8 either after the values are calculated, or what SCE&G
9 has done is actually use that solar shape in coming up
10 with the starting avoided cost numbers.

11 Q And when you say a solar shape, you're talking about
12 sort of a generic production profile?

13 A [HORII] Yes, I am.

14 Q Okay. And how would the generic — for utilities that
15 use that, some variation of this method, how do they
16 generally go about coming up with this solar shape?

17 A [HORII] The solar shape, you know, there are various
18 publicly available resources, like PVWatts. And so that
19 is a public tool that simulates PV output, given
20 different weather locations, and so that's a very common
21 tool. Another thing is just to use data that they have
22 from their system, if there's enough metered solar in
23 the system where they can actually gain specific
24 information. But even without that, you know, something
25 like a PVWatts program.

1 Q Okay. When you say enough metered solar to provide that
2 data, how much is enough metered solar, do you think?

3 A [HORI] Well, I think you would want solar where it
4 covers the service territory that you expect to be
5 affected by solar, so you don't want to just link to one
6 specific location just because – you know, you want to
7 pick up the diversity of solar, the fact that you could
8 have a cloud in one part of town but it's still sunny,
9 you know, 20 miles away, and so you want enough sort of
10 different solar plants so you can sort of let that
11 average out.

12 Q Okay. So what I'm hearing you say is that different
13 solar farms may sort of systematically have different
14 profiles based on things like their location and weather
15 patterns there?

16 A [HORI] They can, yes.

17 Q Okay. And would a single solar facility have a
18 different profile from year to year, based on weather
19 over different years?

20 A [HORI] There certainly would be variations, but, you
21 know, if it's being applied to something like an hourly
22 avoided cost profile, in the end it's probably not that
23 much of a difference.

24 Q The year-to-year difference wouldn't be that much?

25 A [HORI] Right.

1 Q Okay. Might different solar farms vary in their
2 generation profile for other reasons?

3 A [HORII] Yeah, you certainly could have things like, you
4 know, it depends on their tilt, their orientation,
5 whether they're tracking. But we've generally found
6 that, even with tracking versus non-tracking, the solar
7 shapes are still pretty similar. You know, you get a
8 little bit of variation on the sort of earlier parts of
9 the day or the latter parts of the day, but overall
10 they're surprisingly close.

11 Q Okay. When you've reviewed the company's cost
12 calculations, was it clear to you from the documents and
13 work papers how the company had come up with the solar
14 shape that it used for its cost calculations?

15 A [HORII] It was clear they used the solar-farm shape.

16 Q Okay. Was it clear to you that they had used a single
17 year of data from a single solar farm?

18 A [HORII] That's something we actually did not sort of
19 investigate deeply. We were sort of focused on these
20 other capacity issues.

21 Q Okay. Did you hear Dr. Lynch testify yesterday that
22 that was, in fact, how they had generated the solar
23 shape they used?

24 A [HORII] Yes, I did.

25 Q Did that come as a surprise to you?

1 A [HORII] I don't know if that would really be a surprise,
2 just, as I said, you know, solar shapes year-to-year
3 there tends not to be that much variation. Maybe, you
4 know, day-to-day maybe there's a cloud on June 5th and
5 the other it's cloudy on June 7th, but over the course
6 of the year it tends to average out.

7 Q But would you agree that the solar shape of a single
8 solar farm in a single location in a single year might
9 not adequately represent the whole spectrum of
10 generation profiles for solar?

11 A [HORII] Yeah, that – the sort of geographic diversity
12 would be more of a concern to me.

13 Q Okay. And that could have an impact on the calculation
14 of avoided cost rates?

15 A [HORII] It could.

16 Q So, Mr. Horii, we've talked a lot about the DRR
17 methodology, and as you understand it that's performed
18 using a base case and a change case and calculating the
19 difference in revenue between those two; is that right?

20 A [HORII] Yes.

21 Q Okay. And the base case for the DRR method is
22 constructed using load forecasts and supply-side
23 resources that are described in the company's resource
24 plan?

25 A [HORII] That's my understanding.

1 Q Okay. Would you agree that having a different base case
2 — or, that the base case could have a substantial impact
3 on the results of the avoided cost calculations?

4 A [HORII] Are we talking for energy or capacity, or both?

5 Q Either.

6 A [HORII] Okay. So for energy, you know, what really
7 drives the avoided costs are the units that are sort of
8 on the margin. Basically, these are the least-efficient
9 units that you want to be operating. So, you know, if
10 your base case changes because of differences in base-
11 load plants, that's really not going to have much of an
12 impact. On the capacity side, you know, certainly, your
13 base plan is going to sort of drive your evaluation of
14 capacity based on the timing of when you think that next
15 capacity addition needs to be, and also, potentially,
16 what type of capacity addition that is.

17 Q Okay. So if the base case included any unjustified
18 assumptions about generation or load, the DRR method
19 wouldn't necessarily provide an accurate calculation of
20 avoided capacity costs, would it?

21 A [HORII] Yes, that's correct.

22 Q Okay. Did you look at the resource plan that the
23 company used for its base case?

24 A [HORII] I looked at the IRP resource plan but, as far as
25 a base case versus a change case for capacity, I never

1 saw a base case and a change case because the company
2 basically said they're the same and the value is zero.

3 Q Okay. And even if the company had done that, it
4 wouldn't really have been within the scope of your
5 review to look behind the assumptions that were made in
6 the company's base case, would it?

7 A [HORI] I think I only would have investigated that if I
8 thought there was an issue there related to this
9 summer/winter capacity evaluation.

10 Q But you wouldn't have looked behind or second-guessed
11 the company's choices about when it was going to add
12 generation or things like that?

13 A [HORI] I probably would not have.

14 Q Okay. That's not really your – that wasn't really part
15 of your work in this?

16 A [HORI] That's correct.

17 Q So you didn't draw any conclusions as to whether the
18 company's resource plan is optimal, or not.

19 A [HORI] Well, I think I do, you know, have questions
20 about the resource plan just because of the issues I've
21 seen with the potential mismatch between their
22 forecasting of summer/winter demand in their resource
23 plan, and, obviously, their reserve margins, and that
24 raises questions. You know, there's also this issue of
25 this 100 megawatts of additional demand response in the

1 winter that's in the resource plan but that Witness
2 Lynch sort of took out of his rebuttal testimony when he
3 was saying that there still remains this need for winter
4 capacity, even if, you know, there's an 18 percent
5 reserve margin. So I have sort of questions about sort
6 of that resource and how – well, either how correct it
7 was to include the resource plan or how correct it is to
8 exclude from that subsequent analysis.

9 **Q** Okay. So what you're saying is that, in Dr. Lynch's –
10 in his rebuttal testimony, he, if I recall correctly, he
11 provided a calculation showing that, even with an 18
12 percent reserve margin in winter, solar would still have
13 no avoided capacity value? Is that right?

14 **A** [HORI] Basically. He showed that winter would still be
15 the capacity-constrained season.

16 **Q** Okay. But when he did that, he removed that 100
17 megawatts of demand response from his calculation?

18 **A** [HORI] Correct, and that's something that we didn't
19 find out until yesterday, basically, when he mentioned
20 that, because there was no discussion of that. You
21 know, he says he's using existing demand response, but,
22 you know, that's not something I could read between the
23 lines and look at his IRP and know, "Okay, that 100
24 megawatts isn't, you know, part of the existing demand-
25 response program."

1 Q Okay. So, all in all, you do have some questions about
2 whether the resource plan, sort of as a whole, that's
3 presented in the company's testimony, is necessarily
4 optimal or ideal?

5 | **A** [HORII] I do, yes.

6 MR. SNOWDEN: I have no further questions.

7	Thank you, very much.

8 CHAIRMAN WHITFIELD: Thank you, Mr. Snowden.

9 Ms. Ottenweller.

10 MS. OTTENWELLER: Thanks.

11 MR. ELLIOTT: I have no questions.

12 **CHAIRMAN WHITFIELD:** Sorry, I did jump you,
13 **Mr. Elliott.**

14 MR. ELLIOTT: That's All right. You were
15 reading my mind, Commissioner.

16 CROSS EXAMINATION

17 BY MS. OTTENWELLER:

18 **Q** Mr. Horii, there's just one issue that I want to ask you
19 about quickly. You're aware of the settlement reached
20 in the net-metering docket several years ago, correct?

21 **A** [HORII] Generally, yes.

22 Q And that Settlement Agreement notes that value of solar
23 components should be updated and included annually, if
24 and when the capabilities to reasonably quantify those
25 values become available? Does that sound right to you?

1 A [HORII] That sounds familiar, yes.

2 Q The company is taking the position that distributed
3 solar provides no transmission and distribution value at
4 this time, right?

5 A [HORII] That's correct.

6 Q But you note that some jurisdictions do recognize the
7 value that net-metering resources provide to
8 transmission and distribution capacity.

9 A [HORII] Yes, I do.

10 Q In fact, haven't you yourself quantified avoided costs
11 related to transmission and distribution capacity for
12 other utilities?

13 A [HORII] Scores of times, yes.

14 Q I want to ask you about just one of those times.

15 MS. OTTENWELLER: If I may approach the
16 witness.

17 CHAIRMAN WHITFIELD: [Nodding head.]

18 BY MS. OTTENWELLER:

19 Q [Indicating.]

20 A [HORII] [Indicating.] Looks familiar.

21 Q I was hoping it would. So I have provided to you a
22 report that you worked on in 2016, correct?

23 A [HORII] Yes.

24 Q And this was for the California investor-owned
25 utilities?

1 **A** [HORII] Yes, it is.

2 **Q** It's an analysis of the avoided costs related to
3 distributed energy resources?

4 **CHAIRMAN WHITFIELD:** Ms. Ottenweller, do you
5 have copies for the Commission?

6 **MS. OTTENWELLER:** I'm sorry. I wasn't
7 planning on putting it into evidence, so I don't.

8 **CHAIRMAN WHITFIELD:** Okay. Well, we do have
9 some – tell us, again, what this is from? I think
10 your questioning along that line, I think some of
11 the Commissioners wanted to at least see where
12 you're questioning from, but –

13 **WITNESS HORII:** If you want to, you can share
14 this, because I know it well enough, if you need a
15 hard copy [indicating].

16 **MS. OTTENWELLER:** Thank you [indicating].

17 **MR. WOODS:** [Indicating.]

18 **BY MS. OTTENWELLER:**

19 **Q** Mr. Horii, could you just tell the Commission what this
20 report is?

21 **A** [HORII] Sure. That's a report on avoided costs in
22 California, and it's used for all distributed energy
23 resources, so things like energy efficiency, solar,
24 storage, et cetera. It's something we've been doing
25 since 2004 in that jurisdiction, and it's very similar

1 to avoided cost work that we do in New York and other
2 jurisdictions.

3 **Q** And as part of this analysis, you quantified both
4 ancillary services' costs and transmission and
5 distribution capacity costs, correct?

6 **A** [HORI] That's correct.

7 **Q** And, subject to check, on page 28 of that report, it
8 says, "The costs taken from utility rate case filings
9 are used as a reasonable proxy for long-run marginal
10 transmission and distribution investment and is avoided
11 over time with the addition of distributed energy
12 resources."

13 **A** [HORI] That's correct.

14 **Q** Would you agree that those costs were reasonably
15 quantified in that report?

16 **A** [HORI] You know, I would say that – well, first of all,
17 those costs come from utility general rate cases, so
18 they're really ratemaking proceedings that they come
19 from, and they use those in setting marginal-cost base
20 rates. So they aren't strictly sort of a measure of
21 what the actual savings could be from distributed energy
22 resources, but parties sort of not having anything else
23 public and the utilities not having other information
24 available, parties tend to agree to that. There are
25 actually efforts underway now for the utilities to come

1 up with more accurate estimates of that, and there's a
2 proceeding ongoing, and the expectation is actually
3 that's going to introduce a wide range of values, so
4 some values that are much higher in certain areas and
5 some values that are much lower in other areas. So, you
6 know, I would say those numbers are kind of a good
7 ballpark. But they are, you know, mean system average
8 numbers, you know, a bit sort of just representational
9 rather than sort of accurate.

10 **Q** And whether it's the representational numbers that were
11 used in this study or the more extensive study that
12 those utilities are now going in, you agree that SCE&G
13 could do that kind of analysis if it wanted to?

14 **A** [HORII] They certainly could. I think, though, there is
15 the question of how they actually do their planning,
16 because in California utilities have long been either
17 instructed or have taken it upon themselves to really
18 incorporate distributed energy resources into their
19 planning processes, so they actually do expect to be
20 able to get T&D savings because of distributed energy
21 saving resources. We've had – or, we've seen other
22 jurisdictions where DER really isn't incorporated into
23 the planning process very well, and so there really
24 aren't many avoided cost savings that can be reaped in
25 those kind of jurisdictions. There's also the potential

1 that solar – it's very dependent on a particular area.
2 If you have an area that's mostly residential and peaks
3 in either the morning or the evening, then something
4 like solar is probably not going to provide much help to
5 your T&D, or to your distribution system. As you get
6 further up, more like the transmission or the grid
7 level, then, you know, you get enough aggregation, you
8 get enough commercial customers in there, where
9 something like solar could provide some T&D value, but,
10 you know, it is sort of case specific, so I think some
11 care would need to be taken before we would say that
12 there is, you know, a certain T&D value for SCE&G.

13 **Q** So, more robust planning would allow SCE&G to
14 potentially quantify that transmission capacity value?

15 **A** [HORII] Well, it would allow them to quantify and then
16 to potentially be able to achieve those cost savings.

17 **MS. OTTENWELLER:** Thank you. No further
18 questions.

19 **CHAIRMAN WHITFIELD:** Thank you, Ms.
20 Ottenweller.

21 Now we're down to Commissioner questions?
22 Commissioners, questions for this panel.
23 Commissioner Hamilton.

24 **COMMISSIONER HAMILTON:** Thank you, Mr.
25 Chairman.

EXAMINATION

BY COMMISSIONER HAMILTON:

Q Ms. Johnson, on your page four and five of your prefiled direct testimony, you state that undercollected incremental DERP costs will earn carrying costs until next year, when they will be reallocated. Could you talk to me about that a little bit?

A [S. JOHNSON] Certainly. So, the underrecovered balances can earn carrying costs as part of the way Act 236 was designed to make sure the company could promote their DER programs, and so those costs will then be re-evaluated and reallocated in the next fuel hearing.

Q What interest rate will be used?

A [S. JOHNSON] I think it is – you'll have to forgive me. I think that Witness Smith actually discusses that in her testimony, and I can't remember the exact number.

Q Okay. Do you know the amount, by chance?

A [S. JOHNSON] The amount of the underrecovered balance?

Q Yes, sir.

A [S. JOHNSON] I believe that is in my Exhibit -1, where I go through and discuss the underrecovery balance through April 2019 by customer class. And so that's about \$10 million for Residential, \$6 million or so for the Small/Medium General Service, and about \$5 million or so for the Large General Service.

1 Q Approximately \$20 million?

2 A [S. JOHNSON] About.

3 Q Thank you, ma'am.

4 A [S. JOHNSON] You're welcome.

5 COMMISSIONER HAMILTON: Thank you, Mr.
6 Chairman.

7 CHAIRMAN WHITFIELD: Thank you, Commissioner
8 Hamilton.

9 Commissioner Elam.

10 EXAMINATION

11 BY COMMISSIONER ELAM:

12 Q Mr. Horii, on page 12 of your prefiled direct testimony,
13 you have Table 2 there, "Reserve Margin with Alternate
14 Winter Peak Variation," which shows a winter reserve
15 margin of 18.3 percent and a summer reserve margin of
16 13.4 percent, correct?

17 A [HORII] Yes, that's correct.

18 Q Okay. Do you believe, or believe the company should
19 believe, that the extra capacity required in the winter
20 of 211 megawatts changes the company's conclusion that
21 it needs as much capacity in the winter as it does the
22 summer?

23 A [HORII] I think they should see this as indicating that
24 there are problems with their analysis. I don't want
25 the Commission to think that I'm testifying that this is

1 the perfect number. You know, what I've done is I've
2 taken their methodology and just sort of corrected some
3 numbers and shown that, even with these simple
4 corrections, it draws into question sort of the numbers
5 that they have come up with. But I think the better
6 approach would be to use one of those industry-standard
7 methods that have been talked about over the last couple
8 of days.

9 Q Okay. Earlier in your testimony, you said that you had
10 looked at reserve margins in various states?

11 A [HORII] Yes.

12 Q How many states have you looked at their reserve
13 margins?

14 A [HORII] Let's see. The study that I did back then, we
15 looked at 20 different jurisdictions; and probably since
16 then, I've probably looked at maybe another ten.

17 Q Where do those reserve margins — how do they compare
18 with the 21 percent that's proposed here?

19 A [HORII] The 21 percent is on the high side, but it's not
20 out of the range. Typically, what we see is more in the
21 range of, you know, 14 percent to maybe 23 percent. But
22 I think those reserve margins have actually been
23 shrinking over time as utilities become more sort of
24 cooperative or establish more sort of coordination with
25 the neighboring utilities, so they can sort of share

1 some of that risk and they can rely, to a certain
2 extent, on their neighboring utilities for firm
3 capacity, rather than having to build it themselves.

4 **COMMISSIONER ELAM:** Okay, thank you.

5 **CHAIRMAN WHITFIELD:** Thank you, Commissioner
6 Elam.

7 Any further Commissioner questions?

8 **COMMISSIONER FLEMING:** Yes.

9 **CHAIRMAN WHITFIELD:** Commissioner Fleming.

10 **EXAMINATION**

11 **BY COMMISSIONER FLEMING:**

12 **Q** Could you talk a little bit about the capacity value,
13 the PR-2 capacity value, that you recommended?

14 **A** [HORII] Sure. So, you know, my original – or, my first
15 recommendation is to compel the company to produce a
16 capacity value similar to what they did in the prior
17 case. So, you could think of it as sort of a round-the-
18 clock capacity value rather than a solar capacity value.
19 And then we can derate that round-the-clock value with
20 that 19.5 percent value that I discussed, to get it to
21 be sort of more reflective of sort of a solar summer
22 capacity reduction. And if that's not possible, just
23 because of process and procedure, then I think the
24 current PR-2 avoided capacity component should be
25 retained, given that I don't feel that the company has

1 justified their new capacity value.

2 **COMMISSIONER FLEMING:** Okay.

3 **CHAIRMAN WHITFIELD:** Thank you, Commissioner
4 Fleming.

5 Mr. Bateman, any redirect?

6 **MR. BATEMAN:** No redirect.

7 **CHAIRMAN WHITFIELD:** Well, if not, you may
8 step down. And, Mr. Horii, you can be excused.

9 **WITNESS HORII:** Thank you, very much.

10 [WHEREUPON, Witness Horii was excused.]

11 [WHEREUPON, Witness S. Johnson stood
12 aside.]

13 **CHAIRMAN WHITFIELD:** Mr. Whitt and Mr.
14 Snowden, present your witness at this time.

15 **MR. WHITT:** SBA would call Dr. Ben Johnson.

16 [Witness affirmed]

17 THEREUPON came,

18 **B E N J O H N S O N , P H . D . ,**

19 called as a witness on behalf of the South Carolina Solar
20 Business Alliance, who, having been first duly affirmed, was
21 examined and testified as follows:

22 **DIRECT EXAMINATION**

23 **BY MR. WHITT:**

24 **Q** Please state your name and business address for the
25 Commission.

1 A Ben Johnson. 5600 Pimlico Drive, Tallahassee, Florida.

2 Q By whom are you employed and in what capacity?

3 A I have a consulting firm in Tallahassee which bears my
4 name, and I'm a consulting economist with that firm.

5 Q Did you prepare or cause to be prepared the direct
6 testimony consisting of 129 pages with an appendix?

7 A Yes.

8 Q Do you have any questions – or, excuse me. Do you have
9 any corrections or changes to your testimony?

10 A Yes. I noticed one typo that is on page 104 at line 13.
11 The word "more" should actually read "less."

12 Q With the exception of that change, if I asked you the
13 questions today, would your answers be the same?

14 A Yes.

15 MR. WHITT: Mr. Chairman, we'd move Dr.
16 Johnson's direct testimony into evidence as if
17 given orally from the stand.

18 CHAIRMAN WHITFIELD: Dr. Johnson's testimony
19 will be entered into the record as if given orally
20 from the stand.

21 MR. WHITT: Thank you, Mr. Chairman.

22 BY MR. WHITT:

23 Q Dr. Johnson, did you also prepare or cause to be
24 prepared surrebuttal testimony consisting of 40 pages?

25 A Yes.

1 Q Do you have new changes or corrections to that
2 testimony?

3 A Yes. On page 29, at the very end, the next-to-last
4 line, it reads "Generator Program"; it should be "Load
5 Program," "Interruptible Load Program."

6 Q With the exception of that change, if I asked you the
7 questions today, would your testimony be the same?

8 A Yes.

9 MR. WHITT: Mr. Chairman, we'd like to move
10 his surrebuttal testimony into evidence as if given
11 orally from the stand.

12 CHAIRMAN WHITFIELD: Mr. Johnson's surrebuttal
13 testimony will be entered into the record as if
14 given orally from the stand.

15 BY MR. WHITT:

16 Q Dr. Johnson, have you prepared or caused to be prepared
17 a summary of both your direct and surrebuttal testimony?
18 And, if so, can you give that now?

19 A Yes. And I warn you, I'm going to be a few minutes
20 going through this. I put a lot of effort into trying
21 to compactly compress 169 pages of testimony, but it
22 will take a little while.

23 My name is Dr. Ben Johnson. I'm a consulting
24 economist, specializing in public utility regulation.
25 Over the past four decades, I've participated in more

1 than 400 regulatory dockets and provided expert
2 testimony before state and federal courts and utility
3 regulatory commissions in 35 states, two Canadian
4 provinces, and the District of Columbia. I've also had
5 the privilege of testifying before this Commission on
6 several occasions. In most cases, I have testified on
7 behalf of regulatory commissions, consumer advocates,
8 and other government agencies involved in regulation,
9 but I am testifying in this docket on behalf of the
10 South Carolina Solar Business Alliance.

11 My direct and surrebuttal testimony primarily
12 focused on the company's proposed changes to its avoided
13 cost calculations, proposed changes to Rate PR-2, and
14 proposed changes to the tariff structure applicable to
15 qualified facilities under PURPA.

16 In my direct testimony on pages five through ten, I
17 discuss the proposed QF rates and explain why it would
18 be reasonable to expect the proposed rates to be higher,
19 not lower, than the currently approved rates, given the
20 decision to cancel the nuclear units that were under
21 construction.

22 On pages 11 through 35, I discuss PURPA and explain
23 why customers and the general public benefit from QF
24 competition because it drives down costs and shifts risk
25 away from customers onto independent power producers.

1 On pages 36 through 80, I discuss avoided costs and
2 changes the company made to its QF rate calculations.
3 Among other subtopics, within this section I discuss the
4 risks associated with fossil fuels. These risks are
5 borne by ratepayers when power is obtained from the
6 utility's coal and gas plants, and they are avoided when
7 power is obtained instead from a QF at a guaranteed
8 long-term fixed price. Avoiding these types of risks
9 and diversifying away from natural gas were of crucial
10 importance when the company argued in favor of
11 continuing with construction of the nuclear units. In
12 marked contrast, the benefits of avoiding these risks
13 and diversifying away from fossil fuels are being
14 completely ignored by the company in this proceeding.

15 On pages 81 through 118, I discuss proposed changes
16 to the QF tariff design, which will discourage
17 investment by independent power producers and help
18 protect the company from the downward pressures on
19 avoided costs and prices which result from QF
20 competition.

21 The company's anticompetitive proposals are
22 especially unfortunate since they come at a pivotal time
23 when rapid innovation and competitive risk-taking are
24 beginning to shield customers from the enormous risks
25 associated with utility-owned generating plants – risks

1 that were vividly shown by the nuclear construction
2 program, but extend well beyond those particular units.
3 The public would be better served by encouraging
4 competitive entry and economic development within the
5 State, rather than accepting tariff proposals that will
6 further entrench and protect the utility's monopoly
7 power.

8 More specifically, I recommend rejecting the
9 proposal to pay solar generators less than non-solar
10 generators. To the extent there are legitimate concerns
11 about increased solar, the best solution is to refine
12 the tariff design by using stronger, more precise,
13 hourly price signals rather than going in the opposite
14 direction as the company proposes.

15 For similar reasons, I recommend rejecting the
16 proposal to stop paying solar generators for capacity.
17 Solar generators help the utility avoid capacity costs
18 and they should be compensated for this benefit. On
19 pages 119 through 126, I quantify this issue, showing
20 how much customers can benefit when a QF avoids even a
21 portion of these costs.

22 Finally, on pages 126 and 127, I recommend the
23 Commission should reject all of these proposals:
24 reducing the QF capacity rate to zero; reducing QF
25 energy rates when circumstances indicate avoided energy

1 costs have increased, not decreased; removing time-
2 related pricing signals; eliminating standard offer
3 rates for non-solar generators larger than 100 kW;
4 basing rates on a generic solar profile instead of
5 moving toward stronger, precise price signals; and
6 basing rates on a sub-optimal expansion plan that will
7 burden customers with costs and risks that could be
8 avoided by relying more on QF power.

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23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED DIRECT TESTIMONY {W/CORR'N} OF
25 BEN JOHNSON, Ph.D., FOLLOWS AT PGS 649-789]