BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
COLUMBIA, SOUTH CAROLINA

HEARING #11-11192 APRIL 28, 2011 10:30 A.M.

ALLOWABLE EX PARTE BRIEFING

REQUESTED BY SOUTH CAROLINA ELECTRIC & GAS COMPANY – 2011 INTEGRATED RESOURCE PLAN [DOCKET NO. 2011-9-E]; UPDATE ON DEMAND-SIDE MANAGEMENT PROGRAMS, INCLUDING ENERGY EFFICIENCY [DOCKET NO. 2011-49-E]

TRANSCRIPT OF TESTIMONY
AND PROCEEDINGS

COMMISSIONERS PRESENT: John E. 'Butch' HOWARD, *CHAIRMAN*; and COMMISSIONERS Elizabeth B. 'Lib' FLEMING, Randy MITCHELL, Swain E. WHITFIELD, and Nikiya 'Nikki' HALL

ADVISOR TO COMMISSION: F. David Butler, Jr., Esq.

STAFF: James Spearman, Ph.D., Executive Assistant to the Commissioners; B. Randall Dong, Esq., Josh Minges, Esq., and Rebecca Dulin, Esq., Legal Staff; Phil Riley, Tom Ellison, and William O. Richardson, Advisory Staff; Jo Elizabeth M. Wheat, CVR-CM-GNSC, Court Reporter; and Deborah Easterling and Dale Davis, Hearing Room Assistants

APPEARANCES:

K. CHAD BURGESS, ESQUIRE, *along with* ***JOSEPH M. LYNCH, Ph.D.*** *[Manager/Resource Planning], Presenter,* ***HUBERT C. YOUNG III*** *[Manager/Transmission Planning], Presenter,* ***FELICIA R. HOWARD*** *[Director/Demand Side Management], Presenter, and* ***KENNETH R. JACKSON*** *[Vice President/Rates & Regulatory Services, SCANA], Presenter,* representing **SOUTH CAROLINA ELECTRIC & GAS COMPANY**

JEFFREY M. NELSON, ESQUIRE, representing **THE OFFICE OF REGULATORY STAFF**

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Please note the following inclusions/attachments to the record: PowerPoint presentations (PDF)

Also please note: The *Demand Side Management Programs* PowerPoint Slides shown during the proceedings and attached hereto include content which is duplicated on Slides/Pages 6 and 7; however, this duplication did not exist on the hard copies handed out at the proceedings. There results a one-page discrepancy in pagination from Slide/Page 7 onward.

1 P R O C E E D I N G S
2 **CHAIRMAN HOWARD**: Please be seated. Good
3 morning. We'll call this ex parte hearing of SCE&G
4 to order. We'll turn it over to Attorney Butler to
5 read the docket.
6 **MR. BUTLER**: Thank you, Mr. Chairman and other
7 members of the Commission. We have two briefings
8 this morning -- two allowable ex parte briefings.
9 The first one will be South Carolina Electric & Gas
10 Company's Integrated Resource Plan. This comes
11 under Docket No. 2011-9-E. And we also have, under
12 Docket No. 2011-49-E, South Carolina Electric & Gas
13 Company's annual update on demand-side management
14 programs.
15 Mr. Chairman and other members of the
16 Commission, the dockets are in order at this time.
17 **CHAIRMAN HOWARD**: Thank you, Mr. Butler. I
18 believe we'll turn it over now to Mr. Burgess. Mr.
19 Burgess?
20 **MR. BURGESS**: Thank you, Mr. Chairman. Good
21 morning, Commissioners. My name is Chad Burgess.
22 I'm corporate counsel for SCE&G. On behalf of the
23 company, thank you for allowing us the opportunity
24 to appear before you today and talk with you about
25 the IRP that the company filed earlier this year.

1 We've got two presenters who are going to walk
2 you through the IRP. They've got about a 30-minute
3 PowerPoint presentation. Dr. Lynch, you've heard
4 from him before; he's the manager of our Resource
5 Planning. And also we have with us Clay Young, and
6 Clay is going to talk to you all about transmission
7 planning.
8 After their presentation is concluded and
9 we've answered any questions that you may have,
10 we've got a second presentation that will be
11 conducted by Felicia Howard, who's in charge of our
12 DSM programs, and Kenny Jackson, who's the person
13 who's in charge of calculating the rates related to
14 the DSM programs. They also have about a 30-minute
15 presentation to present to you.
16 We are here at your pleasure. Thank you again
17 for allowing us this opportunity, so please feel
18 free to stop our presenters at any point during the
19 presentation and ask whatever questions are on your
20 mind. Thank you.
21 **CHAIRMAN HOWARD**: Before we start, I guess
22 I'll apologize to Dr. Lynch now for my reference to
23 Ph.D.'s in a previous meeting.
24 [Laughter]
25 Glad to have you with us, Dr. Lynch, and Mr.

1 Young.
2 **DR. LYNCH:** Thank you, Commissioner Howard.
3 No apologies necessary. I could tell you were
4 kidding.
5 Well, good morning, Chairman Howard and
6 Commissioners. I too appreciate the opportunity to
7 talk about our IRP.
8 [Reference: *2011 IRP* PowerPoint Slide 1]
9 We filed the Integrated Resource Plan earlier
10 this year with the Commission, on February 28th, in
11 accordance with State law and Commission order.
12 [Reference: *2011 IRP* PowerPoint Slide 2]
13 The objective of the IRP is to develop a
14 resource plan that continues to provide reliable
15 and economically priced energy to our customers,
16 and that meets all environmental regulations.
17 [Reference: *2011 IRP* PowerPoint Slide 3]
18 The plan for this morning is for me to discuss
19 the forecast and the DSM impacts on the forecast,
20 and then our supply plan, and then turn it over to
21 Mr. Young, our manager of Transmission Planning, to
22 go through the transmission planning piece.
23 [Reference: *2011 IRP* PowerPoint Slide 4]
24 Since the IRP is there to meet the growth on
25 our system, I thought it would be good and

1 appropriate to start with an excerpt from the 2010
2 census, it seems to me, to highlight the seemingly
3 inexorable growth on our system and in the State.
4 From 2000 to 2010, the population in the
5 United States has grown 9.7 percent. In South
6 Carolina, the population has grown 15.3 percent, so
7 that's almost -- that's more than one and a half
8 times the national rate. Georgia and North
9 Carolina grew a little faster than South Carolina.
10 On the SCE&G system, we increased the residential
11 customer count by 25 percent. Projecting the next
12 ten years from 2010 to 2020, we're projecting a 20
13 percent increase. And then you can see the South
14 Carolina population, 2010, 4.6 million people.
15 [Reference: *2011 IRP* PowerPoint Slide 5]
16 This is a picture of the historical peak
17 demands on our system and what we project over the
18 next 10 to 15 years. On the table on the right, I
19 have computed compound growth rates, average annual
20 compound growth rates, over ten-year periods. So
21 you can see, for the ten years ending 1980, the
22 growth rate was 5.2 percent, so that's from 1971 to
23 1980, 5½ percent. Now that's pretty strong growth
24 and we believe it's mostly attributable to the
25 increasing saturations of air-conditioning on the

1 system back in the '70s, so we don't expect to see
2 5.5 percent again on the system, unless maybe
3 electric cars start hitting the system, but then
4 the hope there with the electric cars is that most
5 of the load would be at night anyway.
6 In 1990 -- the ten years ending 1990, we had
7 2.6 percent, so that's through the '80s. In the
8 year 2000, 2.7 percent. The ten years ending 2008,
9 you've got 2 percent there. So it looks like, for
10 three decades, from 1981 to 2008, almost 30 years,
11 our growth rate has been between 2 percent, 2½
12 percent, in that range. Then we go to the year
13 2010, look at ten years ending in 2010, it drops to
14 1.2 percent. Clearly, effects of the recession
15 that we've just gone through and hopefully are
16 coming out of. And then our projection, our
17 forecast, is 1½ percent.
18 I'd point out, you can see how the recession
19 has dropped below the growth on the system, and
20 actually reduced the load. We don't see -- right
21 now, we're not projecting a rebound from the
22 recession, really. We sort of -- the way we look
23 at it and characterize it is that we sort of fell
24 in a hole and now we have a normal rate of growth
25 starting from the bottom of that hole. And you can

1 see that's what it looks like, we're just
2 continuing to grow the way we've always grown, but
3 from this lower level. Hopefully it will be a
4 rebound, you know, some potential for load growth
5 on the system, but we, right now, don't see it.
6 Now it is a little bit of a concern to see
7 here's 30 years where we're growing 2 to 2½ percent
8 and now we're projecting 1½ percent, so that gives
9 us in the forecast area, and I think management, as
10 well, a little concern, a little reason to ask
11 questions about what's going on.
12 [Reference: *2011 IRP* PowerPoint Slide 6]
13 So I put -- this is a pretty detailed chart
14 that I've lifted from the IRP, that has some of the
15 details. It's very busy, lots of numbers. But I
16 won't go into too many of the numbers, but I want
17 to explain how we get to that 1½ percent, or at
18 least what is behind that slowdown in growth.
19 That first column of load projections,
20 baseline trend, is where most of the work in the
21 forecasting department takes place. So all our
22 econometric models, all the statistical trends,
23 impacts of population growth, per capita income,
24 industrial production, all of that is captured in
25 our econometric models and generates this forecast.

1 Then from the forecast we're going to subtract out
2 energy efficiency impacts. Now, because we don't
3 have historical experience with the energy
4 efficiency programs and some of the Federal
5 mandates that we're going to talk about, we can't
6 capture in our econometric models their impact, and
7 we have to sort of look forward to see what impact
8 they will have on the load.
9 So the first column here is the impacts of
10 SCE&G programs, starting with nine megawatts,
11 growing to 210 megawatts. The Federal mandates
12 grow over the 15 years. The Federal mandates,
13 specifically, there is a regulation where air-
14 conditioning in the summers had a minimum SEER
15 requirement of 13. So it went from 10 to 13 about
16 2006, so that was a 30 percent increase in
17 efficiency for air-conditioning, and we're trying
18 to reflect some of that on the peak demand. Also
19 there's the mandate on compact fluorescent light
20 bulbs. That affects the load, as well. It affects
21 energy more than demand, but it also affected
22 demand, particularly through the commercial sector.
23 And then, if you add those up, you get the total
24 impact, and that's what we're subtracting from our
25 baseline trend.

1 And so these energy efficiency impacts are
2 where customers add insulation, high-efficiency
3 appliances, high-efficiency lights, something like
4 that, and then when I subtract it from the baseline
5 trend to get the system peak, this is sort of what
6 the -- this is our estimate of what the customers
7 are going to present to the system as the load that
8 we have to meet in some fashion.
9 And you can see we have demand response, we
10 have 225 megawatts of demand response, which helps
11 us meet that gross peak demand. Most of that
12 demand response is interruptible customers, but a
13 portion is standby generation. When I subtract the
14 demand response off, I get the firm peak demand,
15 and this is the demand that we're adding capacity
16 to meet. And that's where I was talking about
17 growing the 1½ percent or thereabouts.
18 A couple of things to point out is, with the
19 SCE&G programs, you can see that when we get to
20 2021, the last five years we have leveled that off,
21 and we've done that in the Forecasting Department.
22 That's not because we believe we won't have any
23 additional energy efficiency impacts there or that
24 the company is going to shut down its DSM programs
25 or anything of that sort. It's just, in the

1 Forecasting Department, we're not sure whether we
2 will hit that 210 megawatts in 2020, or actually in
3 2025. We just thought trending that out and
4 continuing that trend was risky to look at that on
5 the system. When you hit 210 megawatts and then
6 when we add the Federal mandates to that, you're
7 looking at over 300 megawatts' subtraction to the
8 peak demand -- makes me nervous. I have confidence
9 and experience projecting baseline trends. The
10 energy efficiency is a little bit harder, because
11 we haven't seen it yet. We don't know what our
12 programs will do, what our customers will do or
13 cooperate with us, so it's difficult. So we
14 leveled it off, just to -- I don't know -- as a way
15 to address that uncertainty.
16 [Reference: *2011 IRP* PowerPoint Slide 7]
17 Now another way to address uncertainty is to
18 look at scenarios, so we have generated a high and
19 low forecast scenario, specifically because of the
20 uncertainties that we're discussing here. So our
21 base forecast from 2011 to 2020, I have 1.6
22 percent. Maybe I should clarify. 2010 to 2020, I
23 said was 1½ percent. This is 2011 to 2020. So
24 this is pure forecast; there's no actual demands in
25 it. And I get 1.6 percent. The high scenario is

2.7 percent, the low scenario is 0.4.

The high scenario, 2.7 percent, when you think of that 30 years, it doesn't seem that high to me. Also if we get a rebound -- for example, if you calculated the growth rate from 2008, prior to that recession, and looked at the high load growth, the high load scenario, then the load growth is more like 1.8, 1.9 percent. So we don't think high is as unreasonable as the high might suggest.

[Reference: *2011 IRP* PowerPoint Slide 8]

Another busy table that I've lifted from the IRP, but I like this table because it summarizes everything -- all the points of the IRP. And I've covered a lot of them already. So the first seven lines, you can see, is the load forecast. So there's the baseline trend, the energy efficiency impacts, and when I subtract those out, we get the gross territorial load. And again, that's what our customers are going to present to the system.

Demand response, our net territorial peak. We have a firm contract demand of 250 megawatts with North Carolina that expires after 2012. Line seven, then, is the firm obligation or firm peak demand that we have to add capacity to meet.

The next section of the table is our system

capacity. We have -- so this summer, we're going to have 5,702 megawatts available. And you can see, looking through the future, at line ten, for example, base-load, you go to 2016, we're adding 614 megawatts, which is our first nuclear plant. And the second one, 2019. We also have -- and subtracting 90 megawatts, or the -90 megawatts in 2016, and that's to reflect the need to retire some of the coal units on our system. We don't know which units are going to be retired. We're doing that study right now. I guess we probably won't make a decision until some of the EPA regulations are finalized later this year. But we know some would be retired, and so we have this placeholder as a first-pass estimate. Again, in 2019, we've subtracted 210 megawatts, again, for two more units that we anticipate having to retire.

On some of our plans, on line 13, we put in firm purchases; we don't see any purchase reflected there, so we don't believe we'll need any additional capacity until we get to 2016 when we have the nuclear plant on-line. If the load grows faster than we expect it, then we will need capacity in those years, and we're hoping to be able to buy it in the market, sort of a one-year

1 purchase, and hopefully if it's only 100 megawatts,
2 it's not too much capacity, we should be able to
3 get it without a problem.
4 Then line 16 is our reserve margin. We plan
5 to have a reserve margin in the range of 12 to 18
6 percent. If we plan outside that range, we feel an
7 obligation to justify it. So you can see we're
8 above 12 and under 18 until the first nuclear unit
9 comes on, and we get to 21.2 percent. And the
10 justification there is we're adding a base-load
11 capacity. You're always bringing a bulk -- you
12 know, a chunk of capacity when base-load comes on-
13 line, so typically you fall outside of your
14 guidelines or you have a higher reserve margin than
15 usually you want. And the economics of that base-
16 load -- the addition of that base-load capacity
17 justifies the high reserve margin.
18 But notice, then, there's only two years, so
19 2016 and '17 we're above 18 percent and then fall
20 back. The load growth takes care of that, and we
21 get below 18 percent. Then in '19, we add the
22 second nuclear unit, and we're above the 18 percent
23 for three years after that. And of course, we
24 don't know what we'll have to retire. There's a
25 lot of uncertainty on the load growth, a lot of

uncertainty with the impacts of energy efficiency, but we feel this is a very robust plan, that if there is more load growth, that we can respond to it; if there's less load growth, we would be able to retire more units, perhaps. We'll just have to see what happens.

The other thing I want to point out is, way out here in 2025, we have 93 megawatts, so we're assuming in the IRP that we would add a peaker there. It's really a placeholder. We're not doing any cost-benefit, is it -- is a peaker justified in 2025. It's just -- you know, we didn't want to show a plan where the reserve margin would fall below 12 percent.

Also, I guess I should point out, if you remember where we flattened out the last five years of the energy efficiency programs, the last five years were leveled off at 210 megawatts, if we continued that trend the load would've been 150 megawatts lower and we wouldn't need this -- the plan wouldn't need this 93 megawatts out here. So there's not much of an impact to leveling that energy efficiency program.

[Reference: *2011 IRP* PowerPoint Slide 9]

This is just a graphic, really, showing what

1 I've already talked about. The reserve margin is
2 12 to 18 percent. This yellow line going up is the
3 amount of capacity that would reflect a 12 percent
4 reserve margin. The red reflects the 18 percent.
5 So the goal of the planning is to keep the capacity
6 in between those lines.
7 So this straight line here [indicating] is our
8 existing capacity, and it stays in there, you know,
9 between those bands until 2016, and then we pop out
10 with the addition of the new nuclear. Then we're
11 above the line for a couple of years, like I
12 mentioned, and then we pop out again when we add
13 the second nuclear plant. And then we're above the
14 18 percent, as I mentioned, for three years.
15 [Reference: *2011 IRP* PowerPoint Slide 10]
16 This is another table taken out of our
17 Integrated Resource Plan, and it shows our 2011
18 supply portfolio. At the very bottom of the table
19 you can see 5,702 megawatts, so that's our supply
20 capacity. The reason I wanted to show this is to
21 point out that the first three plants -- Urquhart,
22 McMeekin, and Canadys, three plants there and six
23 units -- and I've forgotten. 700 megawatts, 700-
24 and- -- I forget what the addition was. But those
25 three units are all fairly small, 100 megawatts,

1 less than 200 megawatts. I think Canadys 3 is 180
2 megawatts. But they're all -- none of them are
3 scrubbed. So these new EPA regulations may require
4 us to add equipment here to keep them running, to
5 keep them in compliance, so those are potential
6 candidates for retirement.
7 I would also mention that the years, going
8 back 1962 to 1953, so you're talking 50 years or
9 so, plus or minus, so they're pretty old to start
10 investing a lot of environmental equipment there.
11 We would have to think about it. But we're
12 undergoing those studies now and, of course, when
13 we complete the analysis, we'll come to the
14 Commission with our conclusions.
15 One other thing I wanted to point out is I
16 have 90 megawatts here at Kapstone. That's our
17 cogeneration facility. And at least half the
18 generation out of that facility is renewable
19 biomass, so it's not all coal. Half of it,
20 renewable biomass. And with that facility, my
21 understanding is that we have the largest -- or
22 produce the largest amount of renewable biomass
23 generation in the State of South Carolina, so we're
24 very proud of having that facility on the system.
25 [Reference: *2011 IRP* PowerPoint Slide 11]

1 This just shows our capacity mix. So 2010,
2 you can see that nuclear is 11 percent; coal, 43
3 percent. But when we get out to 2019, when we add
4 the second additional nuclear unit, nuclear
5 capacity is up to 28 percent; coal, 33 percent; and
6 gas, 25 percent. So we have a very balanced mix of
7 capacity, which affords the system a lot of
8 flexibility, depending on how -- to react to
9 different growth rates in fossil fuels and fuel
10 rates in the future.
11 I'll mention, too, 28 percent nuclear produces
12 a much larger percentage when you look at
13 generation. And that's my next slide.
14 [Reference: *2011 IRP* PowerPoint Slide 12]
15 So that 28 percent of capacity generates to 55
16 percent of our generation being nuclear. And if
17 you look at non-emitting, in 2019, non-emitting
18 generation is up to 61 percent, and that's a
19 significant increase from where we are today in
20 2010. It was 26 percent.
21 Let's see -- good.
22 [Reference: *2011 IRP* PowerPoint Slide 13]
23 Now, this chart shows the percent of clean
24 energy that we're going to generate. So the three
25 lines -- the slightly-trending-up line that I'm

1 pointing to here [indicating] is the retail
2 generation -- the retail sales on our system. The
3 dotted line on the bottom is the percent of clean
4 energy that we are generating, and you can see in
5 2016 there's a jump up, and in 2019 another jump
6 up, with the addition of the two nuclear units.
7 And then the dashed line here [indicating] is the
8 percentage of clean energy -- well, clean energy as
9 a percent of retail sales. A lot of the renewable
10 energy standards quote a standard to be met as a
11 percentage of retail sales, and that's why we
12 produced this graph. You can see in 2019, the
13 percentage is almost up to 70 percent, and trails
14 off in the neighborhood of 65 or just below 65
15 percent. So we feel very proud about this effect
16 from our nuclear strategy.
17 [Reference: *2011 IRP* PowerPoint Slide 14]
18 This is a projection -- well, some of the
19 history and a projection of the greenhouse gases
20 that the system is emitting. So starting in 2005,
21 we're up to $19 million tons of CO_2. And after our
22 second nuclear unit comes on-line in 2019, we're
23 down just above 19 or 19½ million tons. And you
24 can see we'll be -- we're below -- well, of course,
25 2005 levels, and 1995 levels. I think 17 percent

1 to 2005 levels was a hurdle that was in the last
2 Lieberman -- the Kerry-Lieberman Bill that was
3 considered in the Senate, so we're well below that.
4 I don't think there's any other utility in the
5 States that can draw a picture like us, like SCE&G
6 has here.
7 [Reference: *2011 IRP* PowerPoint Slide 15]
8 So I just wanted to finalize -- or finish the
9 talk with talking about some of the influences on
10 the plan, some of the things that have our concern.
11 So in the forecast, we might have -- the load may
12 grow faster than we expected, you know, if there's
13 a rebound to the economy, if the energy efficiency
14 programs aren't as effective as we hope. And also
15 on the supply side, the EPA regulations that are
16 currently being promulgated, we're not sure what
17 that's going to do to the system, what we'll have
18 to retire; the timing of the COL license for the
19 nuclear units, that's also an area of concern.
20 But overall, even with all of those risks to
21 the forecast, we feel we have a very robust supply
22 plan, a very robust plan for meeting the loads on
23 the system, and it's really the flexibility in the
24 plan that helps us -- helps the plan to be robust
25 and to give us confidence in meeting our customers'

needs.

This is my last slide. Commissioner Howard, will you want to ask questions now, or turn it over to transmission planning?

CHAIRMAN HOWARD: Yeah, let's ask questions of Dr. Lynch now, if that's all right. Commissioners?

COMMISSIONER WHITFIELD: Mr. Chairman.

CHAIRMAN HOWARD: Commissioner Whitfield.

COMMISSIONER WHITFIELD: Thank you. Good morning, Dr. Lynch.

DR. LYNCH: Good morning, Commissioner.

COMMISSIONER WHITFIELD: I've got a few questions here for you. How does SCE&G's estimate of system losses of 4.3 percent of total territorial sales compare with the industry average or a typical electrical utility comparable to SCE&G?

DR. LYNCH: Well, we had -- we pulled all the utilities in the Southeast, and so -- how many? What is there, 50 or so? And we ranked about seventh, I think, in that list. So our losses seem to be smaller than others. Clay, do you want to say something?

MR. YOUNG: I can, yeah. I actually looked at that very recently, and I pulled even a more select

1 group, closer to South Carolina, just the
2 neighboring states. And out of the 15 I looked at,
3 we were fourth.
4 **COMMISSIONER WHITFIELD**: Fourth?
5 **MR. YOUNG**: Fourth. Fourth best.
6 **COMMISSIONER WHITFIELD**: Also, I guess this is
7 probably for you, Dr. Lynch, as well. What risk do
8 you see, if energy efficiency projections do not
9 materialize?
10 **DR. LYNCH**: Yeah --
11 **COMMISSIONER WHITFIELD**: Is your plan robust
12 enough economically to accommodate that scenario?
13 **DR. LYNCH**: Yeah, as we look at the plan as it
14 is now, with our projections, we have some extra
15 capacity. We're above the 12 percent up until 2016
16 when the nuclear, first nuclear plant is scheduled
17 to come on-line. So there is some cushion there,
18 you know, assuming 12 percent is the bottom point.
19 If the load grows faster than that, we're really
20 hoping we can buy, and we expect to be able to buy
21 some capacity for a year or two -- is probably all
22 we would need -- and meet the load growth that way.
23 So we feel pretty comfortable that we won't have a
24 problem prior to the addition of that first nuclear
25 unit, and of course, when we get that on-line, we

1 won't have a problem at all beyond that.
2 **COMMISSIONER WHITFIELD**: How about on the
3 flipside of that, what if your energy efficiency
4 results exceed your projections?
5 **DR. LYNCH**: Yeah, probably what we would do is
6 retire more of the coal units. I mentioned the six
7 that are really at risk. So we could either retire
8 them, mothball them. We might repower some of them
9 and just postpone the repowerment for a few years.
10 Also we might be able to sell some of -- if we have
11 extra capacity, we might be able to sell some of it
12 to the market and defray some of that cost. Worst
13 case, to be honest with you, I'd rather have a
14 little extra capacity on the system than not
15 enough, if you know what I mean.
16 **COMMISSIONER WHITFIELD**: Yes, sir.
17 **DR. LYNCH**: You know, it's the high load
18 growth I think that we worry more about.
19 **COMMISSIONER WHITFIELD**: Another question for
20 you, and I think you probably partially answered it
21 a moment ago, although I'm a little bit -- if you
22 could touch on it again. Again, on the table on
23 page four, the energy benefits you were talking
24 about from the Federal mandates grew steadily
25 through 2020, and then dropped in 2021, then resume

an upward trend.

[Reference: *2011 IRP* PowerPoint Slide 4]

I guess my question is, what's behind that 2021 fall-off, and I think you said that you leveled it off because of uncertainty, I think? Was that your answer a little bit ago?

DR. LYNCH: Yes. Because with those SCE&G programs, we have them growing until 2020. And then we just -- I just held them flat for the last five years, because we're just not sure what those programs are going to do.

The company, our marketing group implementing the programs are focused on the next three years. I think the Commission has seen the costs and impacts of the next three years. So our forecasting had to trend that out for the IRP. And we're just not sure when you get above 210 megawatts there, it's a significant impact on the system, and we thought leveling them off was a reasonable thing to do.

For example, we don't know that we're going to hit 210 megawatts by 2020; it may not be until 2025. I just don't know. But on the other hand, if I continued that growth, by 2025, maybe there would be another 150 megawatts, and in our resource

1 plan that tailing peaker, we wouldn't need to show
2 that on our plan. So it's so far out and so risky,
3 and we have these -- I'm also looking at the
4 Federal mandates that we continue to roll -- I'm
5 not sure those are correct. Those are things we're
6 estimating. And the other thing I didn't mention
7 that I worry about, too, is when you do the
8 baseline trends and we're correlating our load
9 growth with history, population, that sort of
10 thing, some of these energy efficiency effects have
11 already taken place, so some of it is captured in
12 our trend. If you look over the past couple of
13 years, the Federal Government has spent millions of
14 dollars, some of them in South Carolina, to
15 increase efficiency with customers and so forth.
16 Some of that I'm sure is picked up in our trends,
17 so I worry when I've got a column of Federal
18 mandates that maybe I'm double-counting some
19 things. There's just a lot of uncertainty, and
20 that's why we're doing a high load scenario and a
21 low load scenario, to capture that.
22 **COMMISSIONER WHITFIELD**: Thank you, Dr. Lynch.
23 Got a couple more here for you. When will the
24 third-party results from mercury removal efficiency
25 as a result of the SCRs and wet scrubber

installations, discussed on page 18, be available? I think you -- yeah, page 18.

DR. LYNCH: Of the IRP?

COMMISSIONER WHITFIELD: Yes, sir.

DR. LYNCH: It's not in my area, but I would think, after years of experience, we would have some measurement of what is being emitted. So later on this year, probably.

COMMISSIONER WHITFIELD: Later on this year?

DR. LYNCH: I would think.

COMMISSIONER WHITFIELD: You expect these technologies will assist SCE&G in compliance with EPA's Utility MACT Rule?

DR. LYNCH: The -- I know the combination of the SCRs and the scrubbers remove a lot of the mercury, but we don't -- I don't know that we know exactly what the limit on mercury is going to be, and I don't think the rules are finalized till November. So I know they help, they help you get there, but I'm not sure we know exactly what they mean yet.

COMMISSIONER WHITFIELD: For mercury.

DR. LYNCH: For mercury.

COMMISSIONER WHITFIELD: Also on page 27 of the IRP, you predict that the potential EPA

1 regulations would force the retirement of much of
2 the country's coal capacity. Now that the EPA has
3 proposed the Utility MACT Rule and regulations on
4 cooling water intake, what impact do you expect
5 these rulemakings to have on SCE&G?
6 **DR. LYNCH**: I don't know. I'm sure other
7 people in the company are looking at that. I'm not
8 sure what it would mean. Presumably, that we would
9 -- it may mean investment in more facilities if we
10 have to, but I don't know.
11 **COMMISSIONER WHITFIELD**: Thank you, sir.
12 That's all I have, Dr. Lynch. That's all I have
13 Mr. Chairman.
14 **CHAIRMAN HOWARD**: Commissioners? Commissioner
15 Hall.
16 **COMMISSIONER HALL**: Thank you, sir. Good
17 morning, Dr. Lynch.
18 **DR. LYNCH**: Good morning.
19 **COMMISSIONER HALL**: I wanted to ask you about
20 the table in the IRP on page four.
21 **DR. LYNCH**: Yes, ma'am.
22 **COMMISSIONER HALL**: Okay. I understand that
23 you indicated in the 2010 IRP that the energy
24 efficiency programs would reduce sales by 225
25 gigawatt-hours in 2011, but this year you project

only 72 gigawatt-hours, so I was just curious to know --

DR. LYNCH: Oh, why the difference?

COMMISSIONER HALL: Yeah.

DR. LYNCH: I believe that's -- I'm trying to think now how we changed that. I think the biggest impact was with the -- part of that energy has to do with the compact fluorescent bulbs, we have that -- that was going to be a reduction, and I believe we started to think that so many bulbs have been sold already, that maybe all of that impact wouldn't be there. So I think that's the biggest impact.

COMMISSIONER HALL: Okay.

DR. LYNCH: I'd have to go back to dig everything out, to really explain it.

COMMISSIONER HALL: Okay, thank you.

CHAIRMAN HOWARD: Commissioners?

COMMISSIONER FLEMING: Mr. Chairman?

CHAIRMAN HOWARD: Commissioner Fleming.

COMMISSIONER FLEMING: Good morning.

DR. LYNCH: Good morning, Commissioner.

COMMISSIONER FLEMING: I'm dealing with allergies this morning, so excuse me if I sneeze along the way. On page five of the IRP, you have

only 225 megawatts of demand response from year 2011 through 2025. Are there steps that can be taken to encourage more of that? Are you looking at steps to encourage more than that amount of demand response?

DR. LYNCH: Well, there was one hope to expand the standby generator program. We have about 16 megawatts there. But we're still waiting -- there's an EPA regulation that may kill that program -- something about emergency generators having to be modified to comply with the rules. Beyond that, we don't have a plan right now to expand it. As we go in the future, I guess we'd look at that and see if the opportunity arises, or if the need or value on the system comes about. Right now, when you look at our forecast, we don't need any capacity, so there isn't a need, a reason to expand the interruptible program anyway.

And the other thing that we're studying and is part of something I maintain is, if we have a 12 percent reserve margin, there's -- I believe there's a minimum amount of generation required on the system to support meeting the load throughout the year, so I'm not sure the system could handle too much more demand-side management or

1 interruptible programs.
2 **COMMISSIONER FLEMING**: Have you compared that
3 with other comparable companies as yours, what
4 their demand response is?
5 **DR. LYNCH**: Well, the comparisons I have made,
6 if you look at our system, 225 over the 5,000, I
7 think we're like 4½ percent, something in that
8 range. If you look around the country, I have
9 compared to subregions -- like VACAR, for example.
10 I thought VACAR -- I'm trying to remember -- was
11 something like 2½ percent. I haven't looked at the
12 numbers in a while. But VACAR; SERC was down at 2
13 percent, I thought. So we seem to have, when you
14 look at subregions, we seem to have more
15 interruptible capacity than a lot of other systems
16 around the country.
17 Florida, I recall in particular, had more than
18 us, and Florida had 7½ percent on one of the
19 charts, and I imagine that has been changed. But
20 in Florida they're mandated to have a 20 percent
21 reserve margin. If SCE&G was mandated to have a 20
22 percent reserve margin, we would meet that with
23 more demand response, as well. So with Florida,
24 just as a quick example, to have a 20 percent
25 reserve margin and 7 percent demand response, then

they have 13 percent backed by generation, physical assets. On our system, if we're at 12 percent and we have 4 percent as demand response, then you're talking about 8 percent backed by generation. So I mean, that plays into it, as well.

So I thought we were doing -- we were reasonable, maybe better than most, is what I thought.

COMMISSIONER FLEMING: Okay. And let me ask you, on the chart that you had on the screen today, on page nine, on the reserve margin, why is there such a dip projected in 2013?

[Reference: *2011 IRP* PowerPoint Slide 9]

DR. LYNCH: That's the drop in load -- our firm contract to North Carolina, 250 megawatts. That drops the load, so will drop the need for capacity.

COMMISSIONER FLEMING: Okay. All right. And I wanted to ask about the scenario -- future scenarios that you had. Would that be for you, or would that be for Mr. Young?

DR. LYNCH: For the IRP, it would be for me.

COMMISSIONER FLEMING: okay. Which one of those scenarios do you think is the most probable? The greener scenario, the higher-growth one, or the

1 base case, business as usual?
2 **DR. LYNCH**: My guess is the future is going to
3 be a combination of all of them. So I think the
4 future is going to be green -- greener still than
5 it is today. I worry about the load growth. I
6 think our load will grow faster than we're
7 expecting. Just -- electric cars will be a big
8 impact, but when all of that takes place, maybe
9 that's beyond the ten-year horizon. So we're not
10 sure on those scenarios which one is more probable.
11 It's more -- we didn't assign probabilities to
12 those; it was more a discussion of things that may
13 happen that will impact the load and the supply
14 plan and our resource plan, things to sort of worry
15 about and think about. But I don't really have a
16 probability or a clear expectation that one
17 scenario is more relevant than another.
18 **COMMISSIONER FLEMING**: Okay. So you've kind
19 of -- you've built in, it sounds like, the
20 flexibility of, whichever way it goes, that you --
21 **DR. LYNCH**: Well, we -- we think our plan is
22 -- we feel like we're in a good position. SCE&G
23 feels we're in a good position in terms of the
24 supply and meeting the loads, because we've already
25 decided on the nuclear plants, our supply plan is

1 anchored by those two facilities that we're going
2 to build, and we're able to move around -- if the
3 load grows faster, it won't grow too much faster
4 than it is now, so we think we're able to lean on
5 the market to get a few hundred megawatts, if
6 necessary, to supply for a few years until we get
7 the nuclear plants on-line, so we have that kind of
8 flexibility; if the load doesn't grow as fast, then
9 there's no risk of not meeting the customers'
10 demands, you know, if the load is too low. That's
11 not the same kind of worry you have when the load
12 grows faster than that.
13 So it seems to me whatever happens, I think
14 we're in a pretty good -- a pretty good situation.
15 Even, I'd mention too, with the EPA and perhaps if
16 we have to retire coal faster than we need, most of
17 our coal units can burn gas, as well. So you don't
18 want to -- you prefer not to run gas through a
19 boiler in a coal plant. It's not a very efficient
20 way to generate energy, but we could do it for a
21 few years, if necessary. So there's a lot of -- a
22 lot of play in our plan to meet an uncertain
23 future.
24 **COMMISSIONER FLEMING**: And, you know, you're
25 saying that the reserve margin, once the nuclear

1 comes on-line, will bump up, you'll have a higher
2 percentage than you anticipate.
3 **DR. LYNCH**: Yes.
4 **COMMISSIONER FLEMING**: So are you, at that
5 point, planning to hopefully sell off some of that,
6 just as you're hoping to buy some, if you need it,
7 before you get the nuclear plants on-line?
8 **DR. LYNCH**: Yeah -- well, offsetting the cost
9 to our customers is always in the back of
10 somebody's mind, and I'm sure we have a power
11 marketing group whose job it is to buy and sell,
12 trade, to minimize the cost on the system, either
13 sell excess or bring in, buy, power that's cheaper,
14 economy energy, that sort of thing. So I know
15 they're looking at that, thinking, "How are we
16 going to capture benefits for the system from
17 that?" Right now it's too far away to really -- I
18 think to plan a sale. Plus, what did I -- I
19 mentioned there's only two years where we're above
20 the 18 percent. So it's not a lot of capacity
21 there. It's not like we can sign a ten-year
22 contract based on that capacity being above 18
23 percent.
24 And then if you -- then I'll point out again,
25 when you're bringing a block of base-load so big

and then you want to build it big to get the economies of scale, you're going to go above, pop outside the range of the typical reserve margin that the company plans for.

COMMISSIONER FLEMING: And with the debate I guess that's going on between clean energy -- I don't know that it's actually a debate, but the discussion -- and renewable energy, could you talk a little bit about your perspective on that, for the future?

DR. LYNCH: Well, I guess one of the big worries we have in resource planning is that there would be a renewable portfolio standard and someone would mandate a certain level of offshore wind, for example, or solar power, or even renewable biomass. We believe it would be uneconomic and it's adding capacity that we won't -- that we don't need. We also see that our strategy has been to add nuclear, which is very clean and is a great deal of energy coming from nuclear, a lot more than you would ever get from wind or solar. And our customers are paying for the nuclear; we don't want them to have to pay for, you know, wind or solar, which as I mentioned, would be very uneconomical anyway. So you worry about that.

1 With, rather, a clean energy standard, that
2 part doesn't worry us, because if you can count the
3 nuclear, you can see that it does affect our
4 generation significantly. It makes most of it very
5 clean, and we would be able to comply with any
6 standard and certainly would easily meet any
7 standard that any other utility could meet. So the
8 clean energy part, that doesn't worry us much.
9 **COMMISSIONER FLEMING**: So you really are --
10 sounds as if you're banking on the clean energy
11 side of the issue, more than the renewable.
12 **DR. LYNCH**: Yes, we would like nuclear counted
13 as a clean -- because it is a clean energy. It
14 makes so much sense, when you look at the world
15 today and the environment and so forth. Nuclear is
16 just a very logical approach to the problem.
17 **COMMISSIONER FLEMING**: Okay, thank you.
18 **CHAIRMAN HOWARD**: Commissioner Mitchell.
19 **COMMISSIONER MITCHELL**: Thank you, Mr.
20 Chairman. You sort of touched on my question
21 there, and I appreciate it, and it was sort of a
22 follow-up to Commissioner Fleming about the Clean
23 Air Act and what initiatives -- you talked about
24 that on page 18, and describe pollution controls
25 that are in place, and the Clean Air Interstate

Rule. Do you feel like there are enough -- there are technologies in place already now, sufficient, for the reductions under this rule, the Air Transport Rule? Do you think -- and I believe you touched on it -- maybe even new nuclear development might aid in this? Was I following you correctly along this line, as far as clean air and the rules that you have to make in the future? So you feel like, with the increase in nuclear, maybe -- what I'm asking, are there technologies in place now, you feel, to meet these mandates? Or do you see nuclear playing a part of that, or --

DR. LYNCH: Well, if there's any system standard, then nuclear I would think would play a part. At least I hope it does. So if there's a clean energy standard, some percentage of your retail sales, that sort of thing, the nuclear will play a part in it. For SCE&G it certainly would. Part of our concern is with the MACT standards. If EPA requires every plant to have a maximum achievable control technology so each plant -- it's not meeting a standard for the system but it's each individual plant, then there are some of our plants that won't meet that standard -- the six units I mentioned -- and we would have to do something to

1 invest in.
2 In terms of technology, I'm not -- you know,
3 I've asked the question about mercury. I'm not
4 sure how we -- well, I'm sure there's technologies.
5 The SCR and the scrubber takes a lot of the mercury
6 out, and then you'd have to use some kind of -- to
7 go beyond that, some kind of absorbent that you'd
8 throw into the flue gas. I'm sure you could
9 collect it, as well. So I'm sure there's a
10 technology.
11 **COMMISSIONER MITCHELL**: Yeah, and I guess what
12 my point, and along with -- you always get the pros
13 and the cons of nuclear. But as nuclear plays a
14 bigger part, then it could very well aid us in
15 developing cleaner air, mercury emissions. It
16 would take coal-powered plants, in secreting these
17 emissions, and then it'd be really helping
18 everything. Am I following you correctly that --
19 **DR. LYNCH**: Yes.
20 **COMMISSIONER MITCHELL**: -- the whole
21 environment could be helped, under your belief, and
22 what the company stands for now, and --
23 **DR. LYNCH**: Well, it seems --
24 **COMMISSIONER MITCHELL**: -- increasing it?
25 **DR. LYNCH**: -- I think in the country I have

heard the statistic that 50 percent of the energy, or more than that, is generated by coal. And if we're going to get rid of all the coal plants in the country -- which seems to be the road that we're going down -- how are you going to generate that energy? I think nuclear is the only answer right now.

COMMISSIONER MITCHELL: Okay. And you did also speak about, and we talked a little about the carbon capture there on page 27, and sequestering technology, and we're talking about adding to natural-gas-fired plants. How do you see that technology working? Is that more effective? Or -- you may be able to answer this question. Is that -- do you see that affecting the natural gas development, and where we are right now?

DR. LYNCH: What do I believe?

COMMISSIONER MITCHELL: Yes, sir. Yes, sir.

DR. LYNCH: I think if the carbon capture gets mandated and is applied for coal, and then you're going to have the transportation system moving that compressed carbon dioxide to storage facilities, the next target would have to be natural gas. Natural gas emits, well, half as much CO_2 as coal does per megawatt-hour, but it still -- if we're

1 going to burn a lot of gas, it's going to be a lot
2 of carbon dioxide. If the goal is to get rid of it
3 and store it, then I would think the next set of
4 units would be combined-cycles.
5 **COMMISSIONER MITCHELL**: Right. And how does
6 the new phenomenon of the shale gas -- how do you
7 see that fitting into the picture, as far as maybe
8 meeting some of these requirements? And as far as
9 the price, and the price that is affordable now,
10 and how that could change with different
11 environmental restraints or -- just give me a
12 little summary of your prediction of this new
13 phenomenon of shale natural gas.
14 **DR. LYNCH**: Well, shale gas is keeping the
15 price of natural gas in the market lower,
16 certainly, than it would otherwise be. My
17 understanding is that we're getting a deal -- the
18 industry is getting a deal -- because some of these
19 shale plays have to be -- in order to keep the land
20 or the leases, they have to produce gas, something
21 along those lines. So the price of the shale gas,
22 I think, would gravitate up a little bit, hopefully
23 not too much.
24 But the thing that's worrisome is that the EPA
25 is now studying it, the environmental impacts. I

1 think it was three -- was it three Democratic
2 senators came out a few weeks ago with a report
3 saying that diesel fuel being -- millions of
4 gallons of diesel fuel being injected, you know,
5 underground to produce the gas. So I see the
6 environmental costs and regulations and so forth
7 starting to -- may drive the cost of shale gas up
8 significantly.
9 **COMMISSIONER MITCHELL**: And I assume that the
10 company's more-or-less position is, and I believe
11 you stated that earlier, is, doing as much as you
12 can as efficiently and as economically as possible
13 to still keep protecting the ratepayers.
14 **DR. LYNCH**: Right.
15 **COMMISSIONER MITCHELL**: Didn't you state that
16 earlier --
17 **DR. LYNCH**: Yes.
18 **COMMISSIONER MITCHELL**: -- as far as
19 everything you can possibly do? I think -- prices
20 are going up very fast, anyway, and making it
21 economically feasible to continue.
22 **DR. LYNCH**: The world is full of uranium;
23 there's a plentiful supply of uranium, so uranium
24 prices seem to be very stable. So having these two
25 new nuclear plants will be a very good bonus to our

customers once we get them on-line, because those prices would be stable. And then we'd have the gas and the coal to play against each other, depending on where the gas goes. If gas shale keeps the price down, we have a lot of capacity with combined-cycles, our Jasper and Urquhart units, so we could burn a lot of that gas like we're doing today. If the prices do go up, then we could lean more on coal, hopefully. So having the mix of capacities in the future, we think, is the only way to go. It provides a robust response to future uncertainty with fuel prices.

COMMISSIONER MITCHELL: Thank you. Thank you, Mr. Chairman.

CHAIRMAN HOWARD: Commissioner Hall.

COMMISSIONER HALL: Thank you. Thank you, Mr. Chairman. Dr. Lynch, you mentioned electric vehicles. I wanted to ask you, is the company currently doing any studies to meet -- to determine maybe what predictions you might get from customer usage from that?

DR. LYNCH: Well, we have a car -- I think you've seen it -- that's an electric car, and which we've studied, you know, how much energy that uses. But what the cars will look like in the future, I'm

not sure, and what the load will be. So, we have not rolled those into our forecasts, what it would mean for our peak demand forecast. I know we stay current -- we try to stay current, anyway, and involved in the market. I think we -- there were some charging stations that we -- did we donate them? I don't know, but the City has put out, somehow, with the help of SCE&G, so we're hoping to monitor those to see what goes on. But I don't have them in the forecast.

One thing -- it's on my mind, because I've seen that some utilities do actually project some saturation of electric cars and have a resulting higher load forecast because of it. So we haven't done that yet. But it's something that we're looking at and trying to figure out what to do.

COMMISSIONER HALL: Duke has filed a pilot program with electric vehicles. Do you anticipate E&G doing something similar?

DR. LYNCH: No -- that -- it wouldn't come out of my department, so it may be something in the works that I don't know about. But I think no. I think no.

COMMISSIONER HALL: Okay. Thank you, sir.

CHAIRMAN HOWARD: Dr. Lynch, I have a couple

of questions. How many customers are served under the time-of-use and real-time pricing, as you discussed in the -- as was discussed in the IRP? And of that number, how many are residential?

DR. LYNCH: I don't know the customer count, but there are not -- we don't have very many residential customers on the time-of-use. Commercial time-of-use is mandatory for large commercial customers, so they are all on -- that is Rate 24. But the time-of-use for residential, a handful, couple of dozen I think, the last time I -- I would think.

CHAIRMAN HOWARD: Do you have any programs, looking for alternative cost-effective programs that could increase your residential participation?

DR. LYNCH: I'd have to -- I guess I'd have to think about it, and maybe someone in the Rate Department is. But some of the programs that we have, a customer may be able to get more benefit out of some of those efficiency -- what I'm thinking, if you have a thermostat control that's automatic or something, you might be able to get more out of the time-of-use rate. I don't know of any specific programs, to think about it, but maybe Ms. Howard, when she speaks about the demand-side,

programs.

CHAIRMAN HOWARD: Okay.

DR. LYNCH: I don't know.

CHAIRMAN HOWARD: I was going to ask Mr. Hendrix. I see him sitting there nodding off. But you mentioned something about the rate school -- or, your rate group.

[Laughter]

The same with net metering. How many net-metering customers do you have on your system; and in your opinion, is it time to reevaluate the criteria for acceptance of being selected as a net-metering customer?

DR. LYNCH: Well, I think there's -- it's more than 40, and I don't know the exact count. Maybe as many as 50. And I don't know of any reason to reevaluate the criteria. I don't -- I'm not involved too much with the program, other than --

CHAIRMAN HOWARD: Evaluating that? You also discussed PaCE. What is the status of the Palmetto Clean Energy Corporation, and -- what is the status of it now? How many customers currently participate? How many renewable megawatts have been produced as a result of the program?

DR. LYNCH: I'm trying to remember. I'm

1 afraid to give you a number. I don't know. I
2 don't know, sir.
3 **CHAIRMAN HOWARD**: Just for curiosity's sake,
4 could you find out and get back to me with that?
5 **DR. LYNCH**: Absolutely.
6 **CHAIRMAN HOWARD**: I don't want to say a late-
7 filed, but just get me just that question?
8 **DR. LYNCH**: Yes.
9 **CHAIRMAN HOWARD**: What is the status -- and I
10 guess I should've known this and looked at it
11 before I came in, but I didn't. What is the status
12 of the Orangeburg contract, the City of Orangeburg?
13 **DR. LYNCH**: Well, I think we've just signed a
14 long-term contract with them, so the current
15 contract, I think that expired in 2012, and then
16 they've signed up for -- is it ten years?
17 **CHAIRMAN HOWARD**: I thought it was --
18 **MR. YOUNG**: Ten years.
19 **DR. LYNCH**: Ten years.
20 **CHAIRMAN HOWARD**: I didn't see this in your
21 firm contracts. Is that because that's a wholesale
22 contract, or why wouldn't that be listed as a
23 possible --
24 **DR. LYNCH**: Well, Orangeburg, we consider part
25 of the territorial load, so that's part of our

1 baseline trend and it's incorporated in there.
2 **CHAIRMAN HOWARD**: Okay.
3 **DR. LYNCH**: That other thing was an off-system
4 sale to North Carolina.
5 **CHAIRMAN HOWARD**: Okay. You mentioned -- and
6 I'm sorry I didn't catch it, but you were going
7 over, I guess, your chart on page ten, and I
8 thought you said none of those plants were
9 scrubbed. How many of your coal-fired plants --
10 how many of those plants are scrubbed or not
11 scrubbed, or are none of them scrubbed? I know
12 some of them are scrubbed.
13 **DR. LYNCH**: Yeah, all the big ones, so
14 Wateree, Williams, and Cope are scrubbed -- have
15 scrubbers on them.
16 [Reference: *2011 IRP* PowerPoint Slide 10]
17 **CHAIRMAN HOWARD**: And the smaller ones, the --
18 **DR. LYNCH**: Urquhart --
19 **CHAIRMAN HOWARD**: Urquhart.
20 **DR. LYNCH**: -- McMeekin.
21 **CHAIRMAN HOWARD**: Are not scrubbed?
22 **DR. LYNCH**: Are not.
23 **CHAIRMAN HOWARD**: In your chart, in the
24 generation mix, you indicated that in 2019, the
25 nuclear mix would be somewhere like, I think, 55.9

1 percent, or 56 percent?
2 **DR. LYNCH**: Yes [indicating].
3 **CHAIRMAN HOWARD**: The next slide is the one
4 I'm talking about -- no. That might've been right.
5 **DR. LYNCH**: Capacity?
6 **CHAIRMAN HOWARD**: Go back one. Yeah, that's
7 the one I'm talking about. Yeah.
8 **DR. LYNCH**: Okay.
9 [Reference: *2011 IRP* PowerPoint Slide 12]
10 **CHAIRMAN HOWARD**: You mentioned it's 56
11 percent. In 2019, that 56 percent, how will that
12 equate with the rest of the United States? Will
13 that put us pretty well the largest state in
14 nuclear generation, compared in our generation mix?
15 Or do you know how that compares? Do you
16 understand my --
17 **DR. LYNCH**: Yeah, so South Carolina I think
18 would have -- if it's not the state with the most,
19 the highest percentage of nuclear generation, it
20 would be very close. But I don't know -- I haven't
21 -- that's not something --
22 **CHAIRMAN HOWARD**: Yeah, I think we would be
23 pretty close. And if I recall, in the Base Load
24 Review Act hearing we had on Jenkinsville, I
25 believe your projected annual growth was 1½

percent, if I'm not mistaken. If I'm not mistaken. Is that correct? Is that the growth y'all projected?

DR. LYNCH: I think it was higher than that, because it was prior to the recession. And the recession, I think, knocked us down. And then since then, we've put all these energy efficiency programs in place. So I think our projection now is lower than what we had with the Base Load Review.

CHAIRMAN HOWARD: I was curious -- again, another curiosity question. But your contract with Boeing and your solar panels, you don't consider that in your base-load mix, because that's a specific -- let's just say site-specific location? Or do you consider that in your base-load mix, your solar panels at Boeing?

DR. LYNCH: Well, it's an SCE&G generator, so we'll start adding it to our mix. The deal wasn't signed for the IRP, so it's not reflected here, today.

CHAIRMAN HOWARD: Okay. Commissioners, any other questions?

COMMISSIONER MITCHELL: I did have one other one.

1 **CHAIRMAN HOWARD**: Commissioner Mitchell.
2 **COMMISSIONER MITCHELL**: Dr. Lynch,
3 Commissioner Hall asked you about the electric
4 cars, and I was just curious. I mean, we hear that
5 that's supposed to be a phenomenon that's going to
6 explode. However, you know, the ethanol situation
7 was another phenomenon that was supposed to
8 explode, and it appears that a lot of people, you
9 know, have sort of changed their opinion of that.
10 But me being a farmer, I knew how it was going to
11 drive the price of feed up, and bread, and food,
12 and everything else, and not a lot of people wanted
13 to -- I'm just asking this question in relation to
14 -- have you considered or looked into the situation
15 of instead of the electric cars, once again, the
16 phenomenon of natural gas and the shale gas? I
17 know of a guy that lives in Charlotte that just
18 purchased a natural gas car, and he has a fleet,
19 and he loves it so much that he's actually now
20 considering using trucks on natural gas. He's
21 using his own personal car and it's working better
22 than he ever thought it would. And I just -- you
23 know, When you're talking about efficiency and when
24 you're talking about exploring more American
25 possibilities, do you think it would be viable to

do some studies and consideration on that versus the electric car situation? Or have you all talked about that? I mean, we're looking into the future now, and sometimes the future changes fast --

DR. LYNCH: Yeah.

COMMISSIONER MITCHELL: -- and by some of the ex parte presentations that we have had, this seems to be a phenomenon that has really exploded, if we have the environmental issues taken under concern. I just wonder have you considered maybe doing some more studies on that? And just some things I read about the electric car situation -- and correct me if I'm wrong -- that if it's more than two or three per block, then there must be a lot of adjustments done to the transformers, in cities where this might happen, and --

DR. LYNCH: Yeah.

COMMISSIONER MITCHELL: So I guess what I'm asking, maybe I would appreciate some studies looking into these possibilities and what the future might hold, when we have other reports like, you know, you coming to us with ex parte presentations. And give me your thoughts on what I've said.

DR. LYNCH: Yeah. Well, I would guess if the

gasoline engines now are going to be powered by compressed natural gas instead, that wouldn't affect our electric system, so I would have to put on a gas hat for that one. And I haven't -- I mean, the gas people at the company may be thinking about it. We haven't really discussed it. But I'll bring it up and start thinking about it with the guys.

COMMISSIONER MITCHELL: Thank you.

CHAIRMAN HOWARD: Thank you, Dr. Lynch. Mr. Young.

MR. YOUNG: Yes, good morning, Chairman Howard and Commissioners.

[Reference: *2011 IRP* PowerPoint Slide 16]

My comments today are going to focus on several main areas in transmission planning. First, I want to talk about the objectives that we use in planning the SCE&G transmission system. I'm going to talk a little bit about criteria and rules that we must meet when we're designing our system. I'm going to talk at a very high level about our planning process, about how we go from the criteria that we must meet, to an actual plan, in terms of expanding the transmission system. And I'm going to talk a little bit about efforts with other

1 utilities that we have in the area and throughout
2 the United States.
3 [Reference: *2011 IRP* PowerPoint Slide 17]
4 I'll start off with the objectives. These are
5 the main things that we want to accomplish when we
6 are planning SCE&G's transmission system. We want
7 to identify transmission expansion and
8 modifications to safely, reliably, and economically
9 transmit electric power from SCE&G generators to
10 SCE&G customers. That is primary, the first thing
11 on our list, is we want to make sure that our
12 customers can get the power to their load points
13 where they are consuming power, for reliability,
14 and safely, and economically.
15 Also, we want to be able to transmit electric
16 power from off-system purchases to SCE&G customers.
17 Dr. Lynch mentioned there will be occasions when
18 it's more economical to purchase power than it is
19 to generate it ourselves, or there may be a
20 reliability issue where we've lost generation on
21 the system and we need to make a purchase from the
22 market just to make sure the lights stay on. So we
23 want to make sure our system can bring that power
24 in from other systems, coming through the lines
25 that connect our systems with our neighboring

1 systems, that power will actually flow into our
2 grid and through our grid until it arrives at the
3 customers' load points and serves them.
4 We also want to provide interconnection
5 service to all generators. I'm going to talk a
6 little bit more in a minute about a FERC order that
7 mandated that every generator that desires to
8 connect to our grid, we must provide that service.
9 We had another FERC order that opened access to our
10 transmission system, that we want to provide
11 transmission service to all wholesale customers,
12 marketers, and generators; anyone that wants to
13 move power, in, out, or through our transmission
14 grid, we're required to provide that service. And
15 then, of course, we want to maintain synchronism
16 with the Eastern Interconnection. And I'll explain
17 a little bit more about Eastern Interconnection a
18 little bit later, but that basically -- if you lose
19 synchronism with the grid, with the Eastern
20 Interconnection, that's the beginning of a wide-
21 area blackout, and so obviously that's important
22 that we maintain that synchronism.
23 All of this that I have on the list here, we
24 do all this while maintaining compliance with NERC
25 or ERO standards. SCE&G has our own internal

1 planning criteria that we must meet. And then we
2 have FERC rules that govern much of what we do,
3 that we must meet.
4 [Reference: *2011 IRP* PowerPoint Slide 18]
5 Talk a little bit about the ERO standards:
6 North American Electric Reliability Corporation.
7 Back in 1996, this organization developed a set of
8 standards that, at that point, were just voluntary,
9 but I believe all players in the industry
10 recognized the importance of meeting those, so even
11 though there was no penalty or sanction associated
12 with it, I believe systems were designed to this
13 national standard. Everybody's kind of designing
14 their transmission grids to the same level.
15 The Energy Policy Act of 2005 made these
16 standards mandatory. They became law. The Energy
17 Policy Act established the ERO, which is the
18 Electric Reliability Organization, and it gave that
19 organization the right to develop standards,
20 monitor compliance to those standards, and penalize
21 and sanction those who did not meet compliance with
22 those standards.
23 FERC received authority to approve all the
24 standards. Anything that is FERC-approved, we must
25 meet. These standards have come under continuous

1 revisions since they were developed in 1996. We're
2 working on these almost daily with what comes out
3 of NERC and their standards-development process.
4 As far as transmission planning goes, there is
5 a group -- these standards are in separate groups
6 -- there is a group called the transmission
7 planning standards, abbreviated TPL there, that
8 works directly with my responsibility and what we
9 must design our transmission system to be able to
10 withstand. And I've got some links up there; you
11 can use those to go to those documents.
12 [Reference: *2011 IRP* PowerPoint Slide 19]
13 I also want to talk about SCE&G criteria.
14 Back in -- for those of you who remember, back in
15 the late '60s, New York had several blackouts. And
16 in my words, the Federal Government, Congress,
17 said, "Electric industry, fix your problem or we
18 will." And so the response to that by most of the
19 companies in the industry was to develop a planning
20 criteria that would govern exactly how they're
21 designing their system. And we were obviously
22 comparing notes, because if you look at everybody's
23 individual internal company planning criteria, you
24 see a lot of similarities. But we also at that
25 point established, or committed to that we would

1 work with our neighbors, and beyond our neighbors,
2 to make sure that what they're planning to do, what
3 we're planning to do, is going to work together,
4 because we're all part of one power system out
5 there.
6 And we file a FERC 715 annually, and it
7 includes the exact standards that I'm talking about
8 here, so if you care to read those, there's a link
9 right there that will take you to that document.
10 When you get there to that FERC 715 filing
11 document, just go to Part 4 of that document, and
12 it will show you the SCE&G criteria. And there's a
13 lot of good information in that document, too,
14 about the transmission planning process.
15 [Reference: *2011 IRP* PowerPoint Slide 20]
16 I'd like to summarize the standards that we
17 talked about. If you look at the NERC standards
18 for the TPL standard I mentioned, it's two pages
19 long of things that we must test our system for, to
20 make sure that the system can tolerate this event.
21 And SCE&G's criteria is more than a page long, so
22 this is only just a subset of what's on that list,
23 but it is some of the more important ones and some
24 of the ones that will typically drive expansion on
25 the transmission system.

The standards require that at any load level that we plan to operate our system -- so that's where our customers are consuming, light load, 3 a.m., on a spring morning when there is very little load out there, to when it's 102 degrees in August and there's a lot of load out there -- at every load level we must be able to determine that if we lose any transmission line operating at 115 kV or above, our system can tolerate that. "Tolerate" means that the event can happen and we do not have any other facility that's overloaded, we do not have any other facility that is operating outside of acceptable voltage ranges, low and high, in these cases. So that's -- when I say "tolerate" that's what I mean.

We also look at the loss of any transmission transformer. That's the big substations that connect the transmission grid together. If we lose one of those transformers, we still must be able to serve customers, nothing overloaded, and all voltages within range. We look at the entire generating capability at any one plant.

We also look at any substation section and the associated facilities at 115 kV. So inside a substation, if there's multiple lines at a

1 transformer, and a generator, and a capacitor
2 connected to that section, we have to lose all that
3 equipment at one time.
4 We look at all transmission lines on a common
5 structure. If we have multiple lines on a single
6 pole, we look at losing both of those lines.
7 Any single facility, followed by system
8 adjustments, followed by the loss of another single
9 facility. And that last bullet is typically what
10 drives expansion on SCE&G's system. When we're
11 running our tests and we find out we've got
12 something that's overloaded or something that's out
13 of the voltage range, it's typically because we're
14 simulating something like that: We've lost a
15 transmission line. The standard allows us to look
16 for an adjustment. We can redispatch, we can
17 reswitch the system, we can serve load from that
18 direction [indicating] rather than that direction
19 [indicating]. But we must be able to adjust the
20 system such that it can tolerate the next event,
21 and if we can't find an adjustment to put in
22 operations before that next event, then we have a
23 compliance issue there. And so that typically
24 tells us we've got to go build a new line, we've
25 got to go increase the capacity of an existing

1 line, we've got to go add another transformer,
2 increase the capacity of a transformer, go in and
3 put a capacitor installation to support voltage.
4 [Reference: *2011 IRP* PowerPoint Slide 21]
5 ERO rules. I mentioned that we are doing all
6 this planning while we are making sure we comply
7 and adhere to these. Order 888 was the Open Access
8 Rule back in 1996 that allowed anyone to use our
9 transmission wires on a similar basis, equal basis,
10 to how we use our transmission wires.
11 At that same time, Order 889 came out. That
12 OASIS stands for Open Access Same Time Information
13 System. It is the means that we report to every
14 user of the system, whether it's the market or a
15 generator or a load, we report the capabilities of
16 our transmission system and what's available for
17 them to purchase in terms of sending power in, out,
18 or through. The OASIS is also the mechanism that
19 they actually make a request for transmission
20 service on the system, and it's the way we
21 communicate with all customers that are using our
22 system, including our own affiliated power
23 marketing group. They use the same process as any
24 other marketer out there.
25 Order 2003 was the Generator Interconnection.

1 We basically have a standard method; all industries
2 in the United States have a standard method now, of
3 what you do and how you handle generator
4 interconnections, and it applies to SCE&G self-
5 built options. We push our own self-built
6 generation requests through these same procedures
7 that we would an independent power producer.
8 In 2006, Order 2006 came out, and it was
9 another generator interconnection order, but it was
10 focused on smaller generators, less than 20
11 megawatts. It was mostly about the idea that wind
12 was coming and we would need a streamlined, less --
13 more timely process to get smaller generators
14 connected to the system, and so that's kind of just
15 a streamlined process of Order 2003.
16 Order 890 required that all transmission
17 providers, transmission planners -- like me -- have
18 an open and transparent planning process. SCE&G's
19 effort with this, in concert with Santee Cooper,
20 was to create the South Carolina Regional
21 Transmission Planning Process, and we have
22 quarterly meetings with stakeholders. Stakeholders
23 are the municipals and co-operatives that are
24 connected to our grid, to anybody else's grid; it's
25 generators that are connected to our system,

1 including independent power producers; it is our
2 neighboring transmission utilities, they're
3 involved as stakeholders; ORS has representation in
4 our efforts, and participates there; and FERC
5 typically has a staff person listen in at what
6 we're doing with our stakeholder group. And the
7 whole process is about telling anyone who wants to
8 know about how we plan the transmission system,
9 what problems we see in the future, what
10 alternatives we have considered, how we ultimately
11 made the decision that this was the best thing to
12 do on the transmission system, present our plan,
13 take a lot of input. It is a formal part of these
14 meetings to ask the stakeholders to give us input
15 into what we are planning, so that we -- if they
16 know something about the grid that we don't know,
17 like some future forecast -- the co-ops need to
18 tell us, you know, what they think their load is
19 going to be ten years from now, so that we can plan
20 the transmission grid to make sure we can get to
21 serve that co-op load. We know and have forecasts
22 for our loads, but we need other players to tell us
23 about what their needs are going to be, and so all
24 of that flows into the SCRTP process.
25 The actual Order 890 is at that link right

there, if you care to go see it.

[Reference: *2011 IRP* PowerPoint Slide 22]

Now I want to talk about our planning cycle, just to kind of give you a concept of how we move from the test and the criteria that I talked about, to actually a plan. We have power system models. It models all of the generators, load, lines, transformers, capacitors, everything that's part of a grid. We're able to create a computer model of all that equipment, and it will respond like the real equipment will. And so we build a model of SCE&G's system, Duke builds a model of their system, Progress builds a model, Santee, Southern Company, Georgia Power, they build a model, and we put all these models together -- we snap them together -- and create a huge model that allows us to run analyses on it.

Well, we do that for the next ten years. And just as an example, just to kind of take you around this circle right here, this cycle, if we take the model that we've developed, that's got the plans that SCE&G is expecting to do in 2012 -- and Duke and Progress and everyone else, it's got all those plans in the model -- we take that simulation, that base case, and we run all this testing that I

1 talked about, NERC and SCE&G, if we find a problem,
2 something that we don't meet, something is
3 overloaded when we're doing the test or something
4 that's out of voltage, we develop alternatives to
5 that problem. We do a cost-benefit analysis on
6 every alternative that we discover will solve that
7 problem. Out of that information, we will actually
8 select a solution for that problem. We will go to
9 management for approval of that. At that point,
10 that project becomes an item in our 2012
11 Transmission Management Plan and our engineering
12 group goes -- our engineers and our construction
13 group goes and constructs it, as needed.
14 Then in our process, we increment the year to
15 2013 and we do it again. What happens between 2012
16 and 2013 is, Dr. Lynch told you we are anticipating
17 our load to grow, so 1½ per year: Now the load is
18 higher in 2013 than it is in 2012, and so we run
19 these tests again at a higher load level, because a
20 higher load level means different flows on our
21 transmission facilities. And so, it's marginal,
22 but it is different. And so, we look, and is there
23 now a test that we fail, with this higher load
24 level? And we keep cycling this thing around year
25 after year until we get to 2020. And when we get

there, we have an expansion plan for the next ten years and what we're going to do in each of those years.

[Reference: *2011 IRP* PowerPoint Slide 23]

The North American Power System is divided into what's called interconnections. There are four interconnections. SCE&G is in what's called the Eastern Interconnection. It's 41 states and a good part of Canada that are in the Eastern Interconnection -- all this over here [indicating]. There's a Western Interconnection. Texas is kind of the Lone Star and by itself. And then Québec is an interconnection by itself.

What that really means, kind of at a very high level, is this is one electric machine, and so anything that happens in Chicago can impact SCE&G. Anything that happens in Boston can impact SCE&G. Miami. Over here in New Orleans can impact SCE&G. The further away you are from it, the less impact you will get. But there is -- if a major generator trips in Chicago, we can actually measure that to a small degree on our system happening, because we're all part of one network. Now, if Vogtle, right here at the Savannah River, trips, we will measure a significant change on our system, because we're

close to that.

But the point is, we impact each other, and this is why blackouts occur. Back in 2003, it was in Cleveland. Cleveland had the initial startup of the problem that wide-spread into a large part of the Northeast around Lake Erie and into Canada, all over here [indicating]. And that's because the rest of the grid was responding to something that happened in another part of the grid. That's what happens when you have an electric network which we are a part of.

[Reference: *2011 IRP* PowerPoint Slide 24]

US grid planning. Because of this, we want to make sure we are watching this and are focused on and discovering potential problems that could occur. So in working with what I call our US grid planning goals, we focus on the interaction between systems and the impact of that interaction on the reliability of serving load and providing services. Again, it's also close-in, so we're working a good bit with Duke, to determine whether there's anything on their system that could impact our ability to serve our customers, and vice versa. Duke's playing in this game because they want to make sure anything that happens on SCE&G's system

is not going to impact their ability to serve their customers. So we're working together to make sure we discover these things before there are actually problems. And we're using these ten-year models, so we're ahead of the game, hopefully, and we're not going to get -- we're going to solve the problem before it actually becomes a problem.

In these efforts, we want to measure the ability of the grid to transfer power between systems for reliability purposes. I mentioned earlier, what if SCE&G loses a generator? We rely on our neighbors. They instantaneously -- the way the grid works, if a generator trips, other generators instantaneously start producing more power. Not just SCE&G's generators, but Duke's generators and Southern's and Progress. They all respond to that loss because we're in this grid and they've got controls on to do that. They respond to this loss of generation. And we're required, within 59 minutes, to go in and figure out how we're going to replace our loss, and that's why we have spinning reserve -- we may have talked about that somewhere along the way -- but that's why we have spinning reserves in the system, so that we can have generators that are readily available to

1 come up, ramp up, when we lose generation. We have
2 59 minutes to do that.
3 Obviously, we're working with all of our
4 neighbors and want to maintain synchronism with
5 Eastern Interconnection. I mentioned that earlier;
6 I won't say more.
7 And then, of course, we want to reduce the
8 chance of widespread blackouts, especially if the
9 initiating problem is here. We don't want that to
10 be at all.
11 [Reference: *2011 IRP* PowerPoint Slide 25]
12 Here are some of the groups that we work with.
13 There's a Carolinas Transmission Planning
14 Coordination Arrangement. You can see the players:
15 SCE&G, Duke, Progress, Santee Cooper. It's
16 basically North Carolina and South Carolina. We
17 work with those folks to do the kinds of testing
18 that I talked about we do internally. We do those
19 kind of testings on a wider footprint, so we
20 discover those kinds of problems, you know, on a
21 bigger footprint.
22 VSTE is the group above the Carolinas, plus
23 adding Southern Company, TVA, and Entergy, so we go
24 to a wider footprint.
25 SERC is even a wider one that looks from New

1 Orleans to Washington and Savannah to St. Louis,
2 and brings in Ameren, those companies up in
3 Missouri.
4 And then ERAG is the Eastern Interconnection.
5 We actually do work with those folks to discover
6 whether we've got any issues beyond that, beyond
7 the Southeast area.
8 [Reference: *2011 IRP* PowerPoint Slide 26]
9 Last thing I want to talk with you about is
10 the Eastern Interconnection Planning Collaborative,
11 also known as EIPC. This was an effort that was
12 developed by the planning authorities in the
13 Eastern Interconnection about two years ago, and it
14 is receiving funding from DOE. We were granted $16
15 million to conduct this work on the Eastern
16 Interconnection.
17 At the very high level, from my perspective,
18 the whole effort is about providing transmission
19 information that will inform policymakers -- down
20 at the bottom there -- inform policymakers about
21 the transmission costs associated with policies
22 that are being considered.
23 This effort is looking at many different
24 futures. One of the -- I've got some of them
25 listed here. Looking at renewable energy

1 standards. What if the Federal Government comes
2 out with a 20 percent mandate on renewable energy
3 by 2025 and a 35 percent by -- or, a 30 percent by
4 2035? What will be the impact? And the impact in
5 this case is looking at production costs. How
6 would that impact production costs in the whole
7 Eastern Interconnection?
8 What if there's a nuclear resurgence? In
9 other words, what if there's an incentive like with
10 energy credits, production energy credits or loan
11 guarantees that would incent more nuclear? How
12 would more nuclear impact production costs for the
13 whole Eastern Interconnection?
14 Fuel price variability, what if we have a
15 higher -- what if the price of gas is higher than
16 we currently forecast, how will that impact the
17 production? What will be added? What kind of
18 generation will be added? If gas goes up, you
19 would think less gas would be added, something else
20 would be more competitive. So these models --
21 production models would start bringing in these
22 other types of generation. What if the gas price
23 is lower than what we're currently forecasting? It
24 would seem like to me a lot more gas would come in,
25 if you're balancing all of this on the economics of

1 production costs.
2 Capital and operating costs' variability, what
3 if we find that wind capacity is coming in a lot
4 cheaper than we currently think it is? Do you
5 think the models would find we'd need to add more
6 wind? Accelerated energy efficiency and DSM, a lot
7 of that is already in all of our companies'
8 programs, but what if we have -- what if we have
9 more success with these programs than we're
10 currently forecasting? How will that impact the
11 expansion plan, generation needs for the Eastern
12 Interconnection going forward, and how will that
13 impact production costs?
14 Carbon tax, both at a Federal level and at a
15 regional level, what if -- how would any kind of
16 actions by the EPA affect the resource plans going
17 forward? Obviously, a lot of coal would retire.
18 How would that coal be replaced? Would it be
19 nuclear? And all these others will -- all of these
20 futures are having sensitivities run around them to
21 try to capture information about what if there's a
22 carbon tax and, if significant, and impacts by
23 retiring a lot of coal, would we replace it with
24 gas under a low gas price, a high gas price? Would
25 we do nuclear? So the production modeling will

1 give us a lot of information about what these
2 futures mean, in terms of what it would cost to
3 produce energy, and obviously that controls a lot
4 of our rates to our customers.
5 But from my viewpoint, the work from the
6 transmission side is really going to kick in mostly
7 with Phase 2, because in Phase 2 our stakeholder
8 group is going to select three scenarios, and all
9 of the transmission planners that have put this
10 process together from the very beginning are going
11 to go away and we're going to develop detailed
12 transmission expansion plans for what this future
13 will cost. If the stakeholders pick a high wind
14 scenario, they want to see if we have a lot of
15 wind, where's it going to be located -- offshore,
16 onshore, Midwest -- in Phase 2 is going to be how
17 do we get it to the load, and that's where the
18 transmission guys are going to come in, and we're
19 going to say, "All right, we're going to have to
20 build these lines, and we have to increase that.
21 We have to do all this," so we get a transmission
22 cost that's associated with that future, and the
23 whole purpose, looking at the bottom there, is so
24 that policymakers, whether they're Federal or
25 whether they're state, will have a full spectrum of

what the costs of those decisions might be. It's not just a production, it's not just a capital cost; it is a transmission, delivered cost, and "delivered" means meeting it reliably, nothing is overloaded. We can get it from North Dakota to South Carolina and have good voltage. That's going to be hard to do, but that's what we're going to drive through this process. At the end, providing hopefully good information to policymakers, so they can make informed decisions about future policies.

That concludes what I had prepared.

CHAIRMAN HOWARD: Thank you, Mr. Young. Let's take about a ten-minute break -- 10- or 15-minute break. Why don't we come back at 12:25, and then we'll finish up the panel and then we'll go for lunch, and then we will break -- we will complete this afternoon's panel. You understand what I said? I'm not sure I do.

[Laughter]

Thank you.

[WHEREUPON, a recess was taken from 12:10 to 12:25 p.m.]

CHAIRMAN HOWARD: Please be seated. We'll continue with the questions for Mr. Young. Commissioners?

1 **COMMISSIONER FLEMING**: Yes, Mr. Chairman.
2 **CHAIRMAN HOWARD**: Commissioner Fleming.
3 **COMMISSIONER FLEMING**: Well -- now -- good
4 afternoon, Mr. Young. Mr. Young and I -- I have
5 the pleasure of serving with Mr. Young on the
6 Stakeholder Steering Council for EIPC, and I
7 represent the Southeast and EISPC on that
8 committee, and that has been a very educational
9 experience, and very informative. Could you tell
10 us -- you've already talked about EIPC. Could you
11 tell us a little bit about -- specifically -- about
12 SCE&G's involvement with EIPC and the Stakeholder
13 Steering Committee?
14 **MR. YOUNG**: SCE&G is one of the 26 signatories
15 on the EIPC agreement -- that is, all of the
16 transmission planners or planning authorities,
17 actually, in the Eastern Interconnection -- so we
18 are one of the founders of the process. Of the 26
19 planning authorities that are in there, there are
20 eight of them that are defined as principal
21 investigators under the DOE contract, and they
22 actually are running the process. They are
23 companies like PJM, Southern Company, TVA. Some of
24 the large utilities in the Eastern Interconnection
25 are the principal investigators, and they are

1 actually running the process, working with the
2 different working groups that are established to
3 develop models and come up with what the
4 simulations will be.
5 As part of the EIPC process, it's set up, the
6 stakeholder group that Commissioner Fleming and I
7 are part of, called the Stakeholder Steering
8 Council, or Stakeholder Steering Committee. And my
9 role there is I was elected to represent -- one of
10 three representatives in the Southeast to represent
11 our area on the Transmission Owner Sector Caucus.
12 So we meet periodically through conference calls as
13 a group, to come up with what is a TO --
14 Transmission Owner -- position on decisions that
15 are being made by the Stakeholder Steering
16 Committee. And that's the role that I have, going
17 to the meetings that we have and participating in
18 these calls. Once the TO Caucus -- and there's
19 other caucuses, too; there's a Generation Caucus
20 and there's a Load Customer Caucus, and there's the
21 State Caucus, and there’s a Wind Caucus, and
22 there's the NGO Caucus. All of those sectors are
23 part of the process. I'm in the TO part, again.
24 And we inform our voting members through -- who are
25 on the Stakeholder Steering Committee, as to what

our positions would be. TOs have three votes on a 30-vote -- 29-vote system. I think the states have ten votes on that same system. So Commissioner Fleming has a vote on all these decisions that are being made by the Stakeholder Steering Committee.

[Reference: *2011 IRP* PowerPoint Slide 26]

And that Stakeholder Steering Committee right now is doing the things that I've got on this page right here. They're establishing what futures we're going to look at. I mean, before they started meeting, this was blank. They're the ones that came up with these different futures that we're looking at, and they're the ones that are coming up with the different sensitivities in terms of a nuclear resurgence with a low gas price. Would you really build nuclear if you've got low gas? And so the production modeling that is going to occur will establish all that.

So the Stakeholder Steering Committee, which I'm on and Commissioner Fleming is on, is making those decisions about what we're going to look at and what we're going to study. Long answer. I'm sorry.

COMMISSIONER FLEMING: What do you think about the progress of the collaborative so far?

1 **MR. YOUNG**: Well, I think a lot of
2 understanding of different positions and different
3 perspectives, I've learned, personally, by being
4 involved with this effort. We are actually maybe a
5 tiny bit behind schedule, so we were hoping things
6 would move faster, but there's been so much to do,
7 and to take input from all these different areas of
8 our industry that are influenced -- not just the
9 builders and the asset owners, but the users and
10 environmentalists and all that to take into
11 consideration of what their concerns are, and
12 listen through those, and come up with some
13 consensus on, you know, where we're going with this
14 whole effort and what kind of information we want
15 to get out at the end to help us make good
16 decisions as we move forward, has been invaluable,
17 you know, for me.
18 **COMMISSIONER FLEMING**: Have you seen any
19 surprises on the initial modeling outputs so far?
20 **MR. YOUNG**: We have. Surprising for me. But
21 one of the things the group did was develop a
22 business-as-usual case, which basically in my words
23 means that everything we're forecasting today, it's
24 a snapshot, and it's fixed over the next 20 years.
25 And they've actually run the first set of analyses,

1 production costing, of what the fuel -- we don't
2 move the fuel costs around, the gas cost around;
3 it's fixed. We don't move any capital costs
4 around, we don't have any new EPA regulations.
5 Everything is fixed. What do we build in the
6 future? The model came back and told us gas. That
7 was -- everything other than what was already
8 planned and already committed to, which was in the
9 model, so our nuclear units were baseline in the
10 model -- they were fixed in there -- everything
11 else that was needed to meet forecast demand was
12 gas-fired. So that was interesting.
13 **COMMISSIONER FLEMING**: And there's been a lot
14 of discussion about that.
15 **MR. YOUNG**: Absolutely.
16 **COMMISSIONER FLEMING**: Which could impact
17 other sensitivities.
18 **MR. YOUNG**: That's exactly right.
19 **COMMISSIONER FLEMING**: Right. What do you see
20 could be possible consequences to SCE&G and other
21 South Carolina utilities, be they intended or
22 unintended consequences, to this collaborative and
23 what we learn from the modeling efforts?
24 **MR. YOUNG**: Well, I certainly like the EIPC
25 effort, you know, but my last comment there about

1 informing policymakers of the full spectrum of the
2 costs I think has always concerned me. A lot of
3 times I hear that a state may initiate a renewable
4 energy standard and maybe not consider the true,
5 full cost of that decision. I look at this as our
6 opportunity to tell policymakers that here's what
7 the full, true cost is going to be, because you
8 don't just generate it; you have to deliver it.
9 And so the transmission component is going to come
10 in through these mechanisms here in the EIPC.
11 **COMMISSIONER FLEMING**: And there have been a
12 lot of questions about what it would cost to bring
13 in renewables from other parts of the country or
14 whatever --
15 **MR. YOUNG**: Yes.
16 **COMMISSIONER FLEMING**: -- moving on the lines.
17 And this -- everything that the model's put out,
18 the primary purpose is the cost of what it will --
19 **MR. YOUNG**: That's correct.
20 **COMMISSIONER FLEMING**: -- do to make these
21 efforts --
22 **MR. YOUNG**: The EIPC has Charles River
23 Associates under contract that is doing all the
24 production modeling, using their modeling
25 capabilities and tools. they're a vendor that does

this kind of work. And, yeah, their models are running, based on -- the objective is to minimize cost. So, looking at all the things we talked about, under different scenarios or different sensitivities, still, the answer will be to minimize the production costs, considering that that is the future that we have.

COMMISSIONER FLEMING: And I'll ask the question for you. The Chairman had just asked who will pay for that cost. Will it be the customer or whomever? But if you could address that a little bit about -- I guess that would be -- the information that the policymakers would use to make that decision.

MR. YOUNG: I believe, or my opinion is, when you're talking about the resource, if SCE&G must meet a renewable energy standard, then SCE&G's customers will pay for that resource when you're moving -- if that resource isn't local but it's in North Dakota and we've got to get it here to South Carolina. So there's two thoughts there: that the benefiter pays, and so if SCE&G is mandated to buy wind, and it ends up being from North Dakota, we're going to have to pay the transmission to get it here. The other thought, and it's something that

1 FERC is actually working on, and I call it, my
2 perspective, socialization of transmission costs
3 where there's a super-grid out there across the
4 United States that's paid for by everyone. And
5 some people may benefit more from it than others
6 benefit from it, and so that's kind of a concern on
7 our part. You know, we don't mind paying our fair
8 share and having our customers pay their fair
9 share, but we don't want to subsidize other areas
10 that may come up with more stringent renewable
11 energy standards than we have, and so they're
12 getting more bang out of those facilities than we
13 are.
14 **COMMISSIONER FLEMING**: But these models will
15 allow the policymakers to have those facts and
16 figures before them, when they are making those
17 decisions, correct?
18 **MR. YOUNG**: That is correct.
19 **COMMISSIONER FLEMING**: Thank you. I wanted to
20 ask you -- you talked a good bit about NERC and the
21 reliability standards that you're working on, and
22 your involvement with that.
23 **MR. YOUNG**: Yes.
24 **COMMISSIONER FLEMING**: And under FERC's
25 direction, NERC is working to define or redefine an

1 adequate level of reliability in the bulk electric
2 system. To what degree is SCE&G participating in
3 that process?
4 **MR. YOUNG**: We are participating in that
5 through the information that NERC sends out. What
6 they are contemplating there is a set of metrics
7 that basically you would test your system to see if
8 you measured up or not. And so our input is to
9 provide comments, and when the voting comes up, we
10 would actually initiate -- we have four votes
11 within the company to vote on these standards to
12 see if they go forward. If we vote negative, then
13 we're asked to provide comments, and the NERC
14 standards writing teams would go back and review
15 all those things, and make modifications as needed
16 to those standards, and it would come out for
17 another vote, ultimately with a goal to -- from
18 NERC's viewpoint -- is to finally push it through
19 and make it a mandatory requirement.
20 **COMMISSIONER FLEMING**: And what could be the
21 possible impacts to SCE&G and its customers,
22 depending on how these terms are ultimately
23 defined?
24 **MR. YOUNG**: I think SCE&G is in pretty good
25 shape to meet the metrics. I believe our

transmission system is designed well, it's robust, meets all the standards that we have to meet here. Some of the benefits that I see in the way our system is configured is we have a long-standing policy of trying to build generation close to load. That minimizes the amount of transmission you need. That minimizes the losses -- Commissioner Mitchell. It allows you to generate the power where it's being consumed, and so you don't have a reliance on lines that are five states away. If you're buying power from North Dakota, you've got to have lines coming through Illinois, Ohio, Kentucky, Tennessee, and North Carolina to get here. We don't have to rely on those to make sure we can move power from our generating sources to our customers.

So I think we're in good shape in terms of -- as long as we are allowed to continue to do that, as long as we're allowed to move generation from -- move generation -- energy from local generation to local load, I think we'll perform well under any metric. If we're required to buy from somewhere else, that's going to be more of a challenge and could result in cost to our customers.

COMMISSIONER FLEMING: Okay. And talking about the cost to the customer, meeting those

reliability standards, what is that cost? I certainly know that I, for one, think it's important to have reliability as one of its top standards, but could you just give us an idea of what it costs to meet those standards?

MR. YOUNG: From my perspective, Commissioner Fleming, the way SCE&G has designed its system, even before standards were required, is close to what the requirement is now, so I don't believe there's -- there may be an incremental cost, but there's not a lot of facility differences between the way we've always planned our system and the way we are planning it under mandatory requirements.

What it does cost is a lot of people who have to monitor and stay up and show compliance and go through audits and do all the things that are associated with mandatory compliance to standards. So a lot of documentation and work and, when an audit team comes in, we've got to have a whole team of people that can sit down with them and show them what we've done, answer questions, and keeping up with all the things that are required under a mandatory compliance effort like this.

In terms of facilities, I think we've always been designing our transmission system very close

to what the requirements -- the mandatory requirements state.

COMMISSIONER FLEMING: And I want to ask you, during the last rate case I know Mr. Marsh was very strong on being very proactive in tree-trimming, taking those preventive measures. It was going to add some cost. And the stipulation I think that was agreed upon did not include that in there. Could you address a little bit about your -- how you view that, being more proactive?

MR. YOUNG: Yes. We have been very much more proactive with tree-trimming. The event that I mentioned in Cleveland when I was talking about Lake Erie, that was initiated by contact with a tree.

COMMISSIONER FLEMING: Right.

MR. YOUNG: And ever since that has happened, the whole industry has a heightened understanding of how important it is to make sure tree-trimming occurs. So, yes, our cost to trim trees is substantially higher than it was. It has resulted in fewer operations on the transmission grid, also. So it's begun to pay for itself, but the costs have been significantly greater than they were in the past.

1 **COMMISSIONER FLEMING**: But it balances itself
2 out? Is that what you're saying?
3 **MR. YOUNG**: It balances out in terms of impact
4 to our customers, because we don't have an
5 operation, we don't have a failure, we're less
6 likely to impact a customer's process, and homes,
7 and --
8 **COMMISSIONER FLEMING**: And businesses, too, I
9 suppose.
10 **MR. YOUNG**: -- businesses. Exactly.
11 Industry. Yes, ma'am.
12 **COMMISSIONER FLEMING**: And could you talk a
13 little bit about cyber-security? That has become a
14 top issue as far as transmission lines and the
15 grid. Could you talk a little bit about what SCE&G
16 is doing in that regard?
17 **MR. YOUNG**: We have several cyber-security
18 standards that we must meet. They are generating
19 significant cost for us, again, in that, for
20 instance, I am very familiar with our control
21 center, controlling the power grid and the
22 generating units and how power flows. We have -- I
23 wouldn't even call it a firewall, because it is a
24 totally broken system that the Internet cannot get
25 into. And that system has to be able to talk to

1 different devices on our transmission grid. It's
2 got to be able to talk to the breaker down at
3 Williams and talk to the breaker at VC Summer, in
4 case our controllers need to operate that breaker.
5 And so some of that equipment, we can call
6 into it, you know, through our system or through
7 other systems, and the CIP standards -- the cyber
8 standards -- are pointing at those types of things
9 to make sure someone on the Internet can't get into
10 our devices and control our devices. And so, we're
11 trying to break ourselves loose completely from all
12 of that possibility. And we're in good shape with
13 that.
14 That's not really my area of responsibility,
15 but I hear about it, you know, as we're having
16 meetings and things like that, so I wouldn't want
17 to undersell, at all, what we've done, because we
18 may have very limited possibilities out there in
19 terms of people being able to access control of our
20 equipment. I don't know that we have any. But
21 that's what the CIP standards are targeting, that
22 kind of exposed vulnerability.
23 **COMMISSIONER FLEMING**: Okay. Thank you.
24 **CHAIRMAN HOWARD**: Commissioner Whitfield.
25 **COMMISSIONER WHITFIELD**: Thank you, Mr.

1 Chairman. Mr. Young, I'd like to kind of bring the
2 transmission discussion back home here, just a
3 little bit, if I could --
4 **MR. YOUNG**: Sure.
5 **COMMISSIONER WHITFIELD**: -- to South Carolina.
6 And I've got to be careful about how I frame this
7 question. I know you've been in before, with 230
8 kV lines before us before, and we'll probably see
9 you again.
10 **MR. YOUNG**: You will.
11 **COMMISSIONER WHITFIELD**: But I want to ask --
12 and I'm going to ask this in general terms, and I
13 know from the Base Load Review order for the two
14 new nuclear units, we had seen some proposed lines,
15 one to serve growth near the Midlands and one that
16 went to the Lowcountry. And I guess what my
17 question is to you, is if you could give us maybe a
18 brief 30,000-feet fly-over view, if you will, of
19 the planning process, not just for these two units,
20 but for any new generation coming on. How early do
21 you start the process? What -- I guess in terms of
22 time, if you could give us a flow for that process.
23 I'm aware through the media, of course, that there
24 have been public meetings and letters gone out and
25 that sort of thing, even last year. Of course, us

being in the role that we're in, we have no knowledge of that, and I wish you could give us maybe -- not specifically only to these two units, but any new generation that might come on, how early do you start, and give us a brief flow of how that planning process takes place.

MR. YOUNG: Okay. Well, let me answer your second question first, because I'm afraid I'll forget about it. But Dr. Lynch showed that our next increment of generation will be 2025, 93 megawatts. So the nuclear units are what's in our generation interconnection queue, in terms of, you know, what we expect to connect to the grid. So that is it.

In terms of VC Summer No. 2 and No. 3, you're exactly right. When we build VC Summer No. 2, we're going to also build a line from the generation site through Winnsboro, down the I-77 corridor, into Killian, the existing Killian substation there. We're also building a line with Unit 2 from the generating site to Lake Murray, to serve Irmo and the Lexington area, one of the higher growing areas on our system. And then with Unit 3, we're building two lines on the same structure all the way to St. George, South

1 Carolina, to deliver some portion of the power to
2 the southern part of our system.
3 Since the Base Load Relief Act hearing -- and
4 we talked about all this, further development of
5 those plans and how we would do that -- we have
6 come to the point now where we believe all of these
7 transmission lines, except for six miles, is going
8 to be on existing right-of-way. And so the six-
9 mile section is between Blythewood and Killian. We
10 believe that is going to be on new right-of-way.
11 And the media that you're probably seeing are
12 the public workshops that we've held. Anytime we
13 are establishing new right-of-way, we have public
14 workshops where we bring in every impacted
15 landowner that's in that area, going by tax maps.
16 We invite them to a workshop where we discuss what
17 we're doing, why we need to do it, what it will
18 look like, answer any questions that they have,
19 take input from them about anything in our siting
20 process that maybe we didn't know about, all of
21 that influencing how we ultimately decide what the
22 path will be. So there is a six-mile section that
23 is new right-of-way.
24 All of that work is underway. In terms of
25 this body here, I believe I'm right with this, but

I believe later this year we plan to have the public need, necessity and convenience hearings -- siting hearings here at this body, on these transmission lines, in two stages. We're going to do -- what we want to do in Phase 1 with VC Summer No. 2, and then follow that up with what we want to do with VC Summer No. 3.

COMMISSIONER WHITFIELD: Thank you, Mr. Young. That was a good synopsis, and I appreciate the information.

MR. YOUNG: Thank you.

CHAIRMAN HOWARD: Any other Commissioners?

[No response]

Y'all, thank you, very much. And if you'll -- Mr. Burgess, you ready for you next panel?

MR. BURGESS: If you're ready, Mr. Chairman, we're ready.

CHAIRMAN HOWARD: We're ready.

[Brief pause]

Okay, Ms. Howard.

[Reference: *Demand Side Management Programs* PowerPoint Slide 1]

MS. HOWARD: Thank you. Good afternoon, Commissioner Howard and other Commissioners. I'm Felicia Rhue Howard. I'm the director of Demand

Side Management for SCE&G, and I wanted to thank you for the opportunity to appear before you this afternoon to give you an update on what we've been doing with demand-side management. So I'll walk through a brief presentation.

[Reference: *Demand Side Management Programs* PowerPoint Slide 2]

I wanted to share with you this afternoon an update on the DSM organization at SCE&G and tell you what's been going on with our residential program and -- programs, and commercial and industrial program launches, as well as the DSM Advisory Group that was put in place last year.

[Reference: *Demand Side Management Programs* PowerPoint Slide 3]

So I'll begin with the DSM organization. When I was here a little over a year ago, at the hearing to approve the demand-side management programs that we proposed, we had a very small, lean-and-mean organization, myself and two others, an administrative assistant and an analyst.

[Reference: *Demand Side Management Programs* PowerPoint Slide 4]

And since that time, we've been very busy. We've been able to bring on several folks. I'm not

1 going to step you through line by line or box by
2 box, but I just wanted to show you kind of the
3 order of magnitude of change that has occurred over
4 the last year.
5 You'll see the blue boxes represent folks at
6 SCE&G, primarily -- well, I'm sorry -- exclusively,
7 really. The first line of blue boxes are those in
8 the Demand Side Management Department that work
9 directly with the program. We've hired an
10 additional five folks who are responsible for
11 managing the residential and commercial/industrial
12 programs that we have put in place. We've also
13 engaged the services of outside resources to assist
14 in implementing the programs, as well.
15 You'll see the lower blue boxes of SCE&G folks
16 represent those who are dedicated in some form or
17 fashion to support the demand-side management
18 programs, although they do not report directly to
19 the DSM organization. And the green box below, on
20 the left-hand corner, Opinion Dynamics is the group
21 that is also going to be working with SCE&G in
22 evaluating the -- our processes and the impact of
23 our programs.
24 So it just gives you a sense of just how
25 things have changed in a very short period of time.

[Reference: *Demand Side Management Programs* PowerPoint Slide 5]

You might recall that, when we appeared before you to discuss approval of the Demand Side Management program, we had done a fair amount of outreach to customers in our service territory to understand their needs and wants in regard to demand-side management programs, and those findings were that customers wanted to see rebates and incentives, education, and in-home services. And the programs that you see listed there are residential programs. And you can see they cover those three areas pretty extensively. So with that, I want to just walk you through each one of the programs and give you -- kind of remind you of an overview of what each one of the programs is about, and then tell you about the current status of the programs.

[Reference: *Demand Side Management Programs* PowerPoint Slide 6]

So the first program is called Home Energy Report. When we appeared before you before, at that time it was called Usage Benchmarking. That term is probably not a term that a lot of people throw around in their daily lives, so we thought we

1 would development names that more customer-centric.
2 And the Home Energy Report program is one in which
3 customers can participate and opt in to participate
4 by completing an initial home energy survey. And
5 when they complete that survey, they will then
6 receive a report that tells them about their
7 individual home's energy usage, so it gives them
8 some insight into how their home is using energy.
9 Beyond that initial report, they receive
10 monthly reports from there, a monthly energy
11 update, that compares their usage to a peer group,
12 as well as gives them additional customized
13 information based on the information that they
14 provided in the initial survey about their monthly
15 consumption. And this program, as you might
16 recall, is free of charge.
17 [Reference: *Demand Side Management*
18 *Programs* PowerPoint Slide 8]
19 Where the Home Energy Report is right now is
20 that it launched earlier this month. We targeted
21 250,000 of our residential customers. We were very
22 pleased at the response that we've gotten so far.
23 The first customer signed up within seven minutes
24 of the e-mail solicitation going out. We had more
25 than 1,100 customers to sign up in two and a half

1 days. And where we are right now is a little less
2 than 7,500 customers just in the last three weeks.
3 We've established an online portal for
4 customers who have opted into the program, so that
5 they can access energy efficiency tips, even beyond
6 those that they will be receiving in the Home
7 Energy Report and Home Energy Updates. We will
8 begin the monthly reports in the month of June.
9 [Reference: *Demand Side Management*
10 *Programs* PowerPoint Slide 9]
11 Moving on to the next program, Energy
12 Information Display Program is one that provides
13 customers with near-real-time information on their
14 electric usage and their costs, and how those are
15 impacted by their individual activities. The in-
16 home display will be provided at a discount to
17 customers. The device that we're using is an
18 AzTech in-home display, and that is valued at about
19 $150. We preprogram it with the customer's rate
20 and meter ID. That's the way in which the device
21 communicates wirelessly with the customer's AMR
22 metering. The customers can set the device
23 wherever they choose, so long as it is able to
24 communicate with the meter, and they can easily
25 monitor their energy usage and their cost, and see

how their activities are influencing those two dimensions.

We plan to make the device available to customers, as I said, at a discounted charge of $40, credit $20 of that back to them once they have successfully installed the monitor and we have verification of that. Kind of wanted to avoid the, you know, folks getting the monitors and never using them, similar to me having never programmed my VCR over the however many years VCRs have been in place.

The fee, though, for the $40 is waived altogether for low-income customers.

[Reference: *Demand Side Management Programs* PowerPoint Slide 10]

Where this program stands right now as that we launched a Phase 1 of this program in November of 2010. We contacted several of our residential customers who participate on our Voice of the Customer panel and asked if they would be interested in participating in this Phase 1 of the program, in exchange for providing feedback on the device operation. We also, from input from folks representing the small business community, extended that invitation to 42 commercial customers who've

also agreed to provide feedback about the operation of the device.

The feedback has been very insightful about what kinds of information customers like to have, what they know, what they don't know about their electric usage, and how they are able to make use of the device. We plan to use that information and to incorporate it into a Phase 2 launch that's estimated to take place by the end of the second quarter of this year.

[Reference: *Demand Side Management Programs* PowerPoint Slide 11]

The third program has been around for quite some time. It's renamed the Home Energy Check-up. It supersedes a couple of programs that were very similar. This was Tier 1 of a two-tier program when we submitted our DSM application. This program, as well as the next one that I'll share with you, was described as a single program, as a Tier 1, Tier 2, part of a single program. But this program essentially replaced our Value Visit program and what we previously called an In-Home Energy Consultation. It's a walk-through, visual inspection of a customer's home by an SCE&G representative, and they basically provide energy

efficiency recommendations and leave behind a kit consisting of ten CFL bulbs or a heater wrap if that's appropriate, and/or pipe insulation. And they also provide a folder of information about SCE&G and other rebates and incentives, and Federal and State incentives that might be of interest to the customers.

Again, this is another program that's offered free of charge to customers.

[Reference: *Demand Side Management Programs* PowerPoint Slide 12]

That program launched in October of last year. It no longer was the In-Home Energy Consultation; it became the Home Energy Check-Up, together with the Energy Efficiency Kit that we had been providing, in October. And there's a program overview, a downloadable application on our website -- SCEG.com/energywise -- where you can find all of the information on DSM programs. We have had over 750 Home Energy Check-Ups since October.

[Reference: *Demand Side Management Programs* PowerPoint Slide 13]

The Home Performance with Energy Star, at our filing, was called the Home Energy Audit program. And Energy Star is one of the most recognized brand

1 names in our country, and so we wanted to take
2 advantage of that name recognition, and we wanted
3 to rename our program in a way that we felt like
4 customers would be more receptive to it.
5 This is the Tier 2 of the Tier 1/Tier 2
6 program approach. Again, it's a whole-home
7 approach. It's a more extensive -- it's more
8 extensive than the Home Energy Check-Up. It uses
9 diagnostic tools, as opposed to visual inspection
10 and a walk-through approach. It's a market
11 transformation program. The idea of the program is
12 to stimulate customer demand while delivering
13 contractor infrastructure for -- or development,
14 I'm sorry -- contractor infrastructure for retrofit
15 services. It's a comprehensive audit that's
16 provided by a BPI certified contractor on SCE&G's
17 participating contractor list. And we put together
18 a list of those contractors to assist customers in
19 finding folks that are BPI certified, that can
20 conduct this kind of audit, and that can be found
21 at our website.
22 The customer engages the contractor on their
23 own. And typically those contractors charge fees
24 from $300 to $600, but it does vary some. I've
25 heard of some that are lower, I've heard of some

that are higher than that. But we offer incentives up to $2,500 for undertaking a variety of energy efficiency improvement measures that range from air-sealing and insulation improvements to existing heating and cooling systems, change-out of heating and cooling systems, replacement of water-heating systems. Part of the $2,500 credit is $200 towards the cost of the audit if a customer undertakes at least one of the recommended measures. If a customer undertakes multiple measures across several categories, then they are also eligible for a bonus incentive, and right now that bonus incentive is set at $400.

[Reference: *Demand Side Management Programs* PowerPoint Slide 14]

This program launched on March 1st, and we've had two contractor recruitment sessions. The contractor will be key to promoting this program. And we've had those sessions in Columbia and in Charleston. We, so far, have eight participating auditors. Again, as I indicated earlier, they are listed on our website, and you can also find program overviews targeted at both customers and contractors. So for customers to understand how they can participate in the program and for

1 contractors to understand how they can participate
2 in the program, they can find that information on
3 our website.
4 [Reference: *Demand Side Management*
5 *Programs* PowerPoint Slide 15]
6 Energy Star Lighting is another residential
7 program. At the time that we made our application,
8 it was the Energy Star Lighting & Appliance
9 program. We had decided that we don't have any
10 appliances that were cost-effective for us, at the
11 time of the filing, so we renamed the program
12 Energy Star Lighting, once we got quite a few
13 questions about, "What kind of appliances do you
14 have?" Well, since there were no appliances in the
15 Lighting & Appliance program, it's been renamed
16 Energy Star Lighting.
17 The idea of this program is to increase
18 awareness and market share and purchase of Energy
19 Star qualified CFL bulbs and CFL fixtures. And
20 we're offering this program through really two
21 mechanisms: One is a mark-down with some retailers
22 that's automatically taken; and then some other
23 smaller retailers, we are providing in-store
24 coupons for customers to complete in the store for
25 the discounts to be taken at the register. The

1 mark-downs are typically $1.50 -- up to $1.50 per
2 bulb, $10 per CFL fixture. The in-store coupons
3 are typically $1.50 per single or multi-package
4 bulb.
5 So each participating store does one or the
6 other. You either do mark-downs or in-store
7 coupons, but not both. We have provided a number
8 of point-of-purchase materials, like banners or
9 signs, stickers, and things of that nature, to
10 bring -- to call customers' or shoppers' attention
11 to those discounts.
12 [Reference: *Demand Side Management*
13 *Programs* PowerPoint Slide 16]
14 And this program launched on Valentine's Day
15 of this year. We have mark-downs -- you may have
16 seen -- in Home Depot, Costco, Wal-Mart, Sam's
17 Club, Lowe's, and Ace Hardware. The in-store
18 coupons are currently at True Value. The effort to
19 recruit additional retailers to participate in this
20 program is ongoing, and we expect to add some very
21 shortly in the near future, across other genres
22 besides hardware stores. We're looking at some of
23 the dollar discount stores, we're looking at
24 grocery stores, pharmacies, so across a wide
25 variety of genres where we believe that people will

1 appreciate the discounts and make these purchases.
2 We've been doing a number of in-store lighting
3 demonstrations. Those will continue to be ongoing.
4 The list of store locations and the addresses of
5 protecting stores can be found on our website, and
6 there are also links to additional educational
7 information about CFL lighting, kind of debunking
8 some of the myths about, you know, the limited
9 options and things like that, to let folks know
10 that there are a number of options for CFL
11 lighting, as well as information about proper
12 disposal of the bulbs. So far, since February --
13 middle of February -- we've sold over 130,000
14 discounted bulbs.
15 [Reference: *Demand Side Management*
16 *Programs* PowerPoint Slide 17]
17 And you'll see here, this is a picture of the
18 lighting aisle at the Home Depot on Harbison
19 Boulevard, and you see the signage -- I might get
20 to use this little laser pointer, after all -- you
21 can see the signage there, with the "Buy and Save,"
22 you know, "Brought to you by SCE&G" is what it says
23 next to the SCE&G logo. You can see also on the
24 bottom picture, it shows that the Home Depot --
25 they show what the price was and then what the

1 price is with the SCE&G discount; it's a pretty
2 significant discount.
3 [Reference: *Demand Side Management*
4 *Programs* PowerPoint Slide 18]
5 The Heating & Cooling and Water Heating
6 Equipment, when we came before you before, was the
7 New HVAC Efficiency Equipment program. And it was
8 a mouthful then; it's still a mouthful now, but, in
9 our thinking, maybe a little more customer-centric
10 from the standpoint of a lot of folks may not
11 necessarily know what “HVAC” stands for, but
12 "heating and cooling" is pretty self-explanatory.
13 This program is designed to promote
14 installation of high-efficiency heating and cooling
15 equipment and non-electric-resistance water
16 heating. And the contractors play a pivotal role
17 in this process. They are also going to -- they're
18 not only going to be promoting this program to
19 their customers, but they'll also be responsible
20 for submitting online applications on behalf of
21 customers.
22 We're going to be introducing a quality
23 installation component in 2012 for those
24 contractors who want to distinguish their services,
25 so not only will they be installing more energy-

1 efficient equipment, but they also will be equipped
2 to better install those, because there's an
3 opportunity, a significant opportunity, to improve
4 efficiency just by having a properly sized unit, by
5 having properly installed ductwork, and that type
6 of thing.
7 The incentives for this program range from
8 $200 to $525, and you can see there the list of the
9 different types of equipment: central air-
10 conditioning, heat pumps, natural-gas tank or
11 tankless, propane, electric water heater --
12 electric heat-pump water heaters, and solar water
13 heaters.
14 [Reference: *Demand Side Management*
15 *Programs* PowerPoint Slide 19]
16 This program also launched on March 1st.
17 We've had eight contractor recruitment sessions in
18 the past few weeks. Four more are scheduled.
19 We've covered our service territory. We've offered
20 sessions in Columbia, Lexington, Charleston,
21 Beaufort, and Aiken. We've had plumber recruitment
22 sessions, as well, for those who may not be
23 interested in HVAC equipment, but they would
24 certainly be installers for water-heating
25 equipment. We've had seven of those sessions; we

have nine more scheduled. We've done those by webinars in some instances. We've also had them on-site in Columbia and Lexington and Charleston.

We have, so far, 70 participating HVAC and plumbing contractors. They are listed on our website. Again, there are program overviews targeted at both customers to increase their interest in the program, as well as contractors to equip them with information about how to access the program for their customers.

[Reference: *Demand Side Management Programs* PowerPoint Slide 20]

The second program -- second component of the HVAC program is the Heating & Cooling Efficiency Improvements program -- again, kind of what I was getting at earlier, that you can have efficient equipment, but if your highly efficient equipment is blowing into ductwork that is leaky or has fallen down underneath your home, it doesn't do you a whole lot of good. The idea with the Heating & Cooling Efficiency Improvements program, which was previously called the HVAC -- Existing HVAC program, the idea with this program is that, again, contractors play a critical role. They'll be responsible for submitting online rebates. They

must also participate in SCE&G-sponsored technical training. There will be a particular protocol that they will be expected to utilize and offer in these tune-ups. What we found is that contractors across the service territory have different definitions for what a tune-up is. There's not a standard for what a tune-up is. So some things are very basic that contractors offer and may call a tune-up, and some things may be pretty extensive and still called a tune-up. So we want to have a single protocol where we train those contractors on what that protocol is. The technical training that we're offering is attractive to those contractors because, in many instances, they can earn continuing education credits for their next certification.

The incentives for this program range from $60 to $150. Again, the HVAC tune-up, duct sealing, and duct insulation are the eligible measures for the program.

[Reference: *Demand Side Management Programs* PowerPoint Slide 21]

This program launched on March 1st. We've had a number of contractor recruitment sessions in conjunction with those for the Heating & Cooling

and Water Heating Equipment program, so the same audience of people, the same kinds of participants tend to be interested in both, so again, we covered the service territory. We've had two technical training sessions so far. We have five more scheduled, and they will be held in Columbia, Charleston, and Beaufort.

So far we have 23 participating HVAC contractors that are participating in the Efficiency Improvements program. They are listed on our website. Again, the program overviews for both contractors [sic] and for contractors are on our website, as well.

[Reference: *Demand Side Management Programs* PowerPoint Slide 22]

Energy Star New Homes program is one that's designed to accelerate the penetration of Energy Star qualified homes in SCE&G service territory. Significant energy savings are associated with the Energy Star homes. They typically are 15 percent more efficient than those homes built to code. With the increase from the current Energy Star standard to that of a higher standard that took place April 1st -- effective April 1st -- to Version 2.5, compared to the current building code

1 standard in South Carolina currently, it's as much
2 as a 30 percent increase in efficiency. So, pretty
3 big savings with this program.
4 Builders participate in the program by
5 committing to building a certain number of Energy
6 Star qualified homes. They must use a HERS rater.
7 That is a requirement of Energy Star, that you have
8 to use a HERS rater in order to have your homes
9 certified as an Energy Star home.
10 We're paying incentives of $750 per qualified
11 home, with an adder incentive of $250 if a customer
12 -- or a builder elects not to install the standard
13 electric-resistance water heaters. If they're able
14 to do something that reduces that electric-
15 resistance load on our system, we give them an
16 additional $250 bonus incentive.
17 [Reference: *Demand Side Management*
18 *Programs* PowerPoint Slide 23]
19 This program launched on March 1st. We've had
20 four builder and rater recruitment sessions in
21 Columbia, Lexington, Charleston, and Aiken. We
22 have 28 participating builders so far, and 15
23 participating raters. We've had over 1,200 homes
24 committed between now and the end of this year, to
25 this program, so a pretty substantial increase in

Energy Star homes, if all of those homes come to fruition -- which they may not, but even if a significant amount of them do, it would be a tremendous influence in our service territory and on an energy savings for those homes.

We've had implementation sessions held for those builders who have committed, who have indicated the number of homes that they'd build. We went further with them in conducting implementation sessions. Kind of gave the go-forward-and-prosper sign, and provided them with Energy Star signage that they can use in their developments. Again, as I indicated earlier, Energy Star is a very well-recognized brand. Many builders see a lot of value in having that signage and being able to indicate they are an Energy Star builder.

The builder and rater, customer program overview information, like the other programs, is available on our website.

[Reference: *Demand Side Management Programs* PowerPoint Slide 24]

That concludes the residential programs. We do have two commercial and industrial programs. The first is the Commercial & Industrial

Prescriptive program. It's basically a simplified method to encourage energy-efficient purchases among commercial and industrial customers. It covers a list of, really, common measures that cut across all types of commercial and industrial establishments.

You can see there a list of the types of energy efficiency incentives that we're offering for lighting, for new-construction lighting, for LED traffic signals, for HVAC, chillers, for variable frequency drives, food service equipment, and other high-efficiency equipment that tends to cut across a variety of commercial and industrial users.

This program requires a pre- and post-installation verification on sample projects and all projects -- on a sample set of projects and then on all projects over a certain size and cost threshold, to basically just confirm that what the customer has installed is operating properly and is going to deliver the energy savings that are expected.

Trade allies are recruited to participate in this program through energy -- through education sessions regarding the program protocols and

1 incentives that we're offering. And then customers
2 are recruited through a number of outreach
3 activities that reach the commercial and industrial
4 community. We also have SCE&G account
5 representatives that call on those customers on a
6 regular basis.
7 [Reference: *Demand Side Management*
8 *Programs* PowerPoint Slide 25]
9 The Commercial & Industrial Prescriptive
10 program launched in October of last year. The
11 first set of incentives that we offered were
12 related to lighting. We've had four trade ally
13 education sessions in Columbia and Charleston. We
14 have nearly $120,000 in rebates that either have
15 been awarded or committed. Our first rebate check
16 -- and you see a picture of the big check
17 presentation -- here recently was presented to the
18 Charleston County School District. They were our
19 first recipients of those incentives. They
20 received a check for $50,000 for a lighting
21 retrofit that they did.
22 [Reference: *Demand Side Management*
23 *Programs* PowerPoint Slide 26]
24 The Commercial & Industrial Custom program is
25 the last of our programs I want to talk with you

about today. It provides incentives to offset the costs of energy efficiency measures that are not covered by the prescriptive program. Those projects tend to be more unique to a customer's operation, perhaps more specialized. Customers apply for those incentives in advance of initiating any work. All of the projects must be preapproved because of their customized nature. The incentive amounts are determined on a case-by-case basis; we evaluate the benefits of what's being proposed in terms of the payback, the energy savings to be expected.

the incentives are capped at $25,000 per customer, per account -- I mean -- sorry, per customer account per year. And again, in the same way that the prescriptive customers are recruited, we recruit those customers through a number of outreach activities, as well as through the SCE&G account representation group.

[Reference: *Demand Side Management Programs* PowerPoint Slide 27]

The status of this program: Well, the application for this program will be available on tomorrow, on our website. And so the installations on or after May 1st are rebate eligible. So this

1 program, as of two or three days from now, we will
2 have launched all of our DSM programs that were
3 presented to you on last year.
4 [Reference: *Demand Side Management*
5 *Programs* PowerPoint Slide 28]
6 Just to tell you about the DSM Advisory Group:
7 You may recall that we put in place an advisory
8 group with membership consisting of representation
9 from ORS, the Coastal Conservation League, the
10 South Carolina Small Business Chamber, the
11 Governor's Office is representing our low-income
12 constituency, and Kimberly-Clark -- a
13 representative from Kimberly-Clark is representing
14 our industrial customer interests.
15 We convened our first meeting in September of
16 2010. We met again in January, and we'll meet
17 again this year, either later on this spring or in
18 early summer.
19 And that's all I have to share with you about
20 the programs. I'll turn it over to Ken Jackson.
21 Unless you have questions now.
22 **CHAIRMAN HOWARD**: Why don't we ask questions
23 of Ms. Howard, since the subject matter is so
24 different between Ms. Howard and Mr. Jackson.
25 Commissioners, any questions of Ms. Howard?

1 **COMMISSIONER FLEMING**: Well, Mr. Chairman, I
2 have a question.
3 **CHAIRMAN HOWARD**: Commissioner Fleming.
4 **COMMISSIONER FLEMING**: I wanted to ask you
5 about the energy efficiency study. In the Order
6 2010-472, we required SCE&G to complete an energy
7 efficiency potential study, and it was to be
8 presented to the advisory group and parties by
9 November 1, 2010. Is this advisory group the same
10 one as the DSM group?
11 **MS. HOWARD**: Yes, it is.
12 **COMMISSIONER FLEMING**: Okay, it's one and --
13 so, you do have that group together.
14 **MS. HOWARD**: Yes.
15 **COMMISSIONER FLEMING**: Has the study been
16 completed --
17 **MS. HOWARD**: Yes.
18 **COMMISSIONER FLEMING**: -- and presented?
19 **MS. HOWARD**: Yes. The study has been
20 completed and presented. We might have missed the
21 November 1st. I think we got an extension of five
22 days on that. But the parties agreed to the
23 extension of five days on that. We did present
24 that; it was the topic. I guess we sent it out via
25 e-mail, and maybe mail. I don't remember. But it

1 was sent to all the folks on the advisory group.
2 And in January of 2011, in the meeting in January,
3 we did a walk-through of that with the -- ICF
4 International was the company that put together
5 that potential study, and we had one of their
6 senior officers, David Pickles, to present -- you
7 know, to walk them through that study.
8 **COMMISSIONER FLEMING**: Could you briefly
9 describe some of the highlights of that report?
10 **MS. HOWARD**: Very similar to the efforts that
11 were undertaken in developing the DSM portfolio
12 that we proposed last year -- or in 2009, I guess,
13 from our application. Very similar, just over a
14 longer time horizon. So the portfolio that we
15 proposed to the Commission in 2009 was over a
16 three-year time span, and this potential study done
17 here recently was over a longer time horizon, a 15-
18 year time horizon.
19 **COMMISSIONER FLEMING**: Okay. And in the
20 settlement agreement, you would consider renaming
21 -- expanding the Energy Information Display
22 program.
23 **MS. HOWARD**: Yes, and we did. And that's why
24 in Phase 1, it was initially -- when we submitted
25 our application, it was a residential program. We

did expand it to include small commercial customers with AMR metering. The challenge for expanding that program is, in part, the technical limitations of the device. So there's a certain number of feet that device must be in proximity to the meter. So if you were in a strip shopping center, for instance, and you happen to be the last tenant in a mall that was eight or ten shops long and the meter bank was at the opposite end of the mall, the device would not work for you the way it would for someone who was the tenant on the opposite side of the wall from the meter bank. So that's part of what makes that device challenging for commercial customers.

COMMISSIONER FLEMING: So that's how you chose the companies --

MS. HOWARD: Yes.

COMMISSIONER FLEMING: -- to include, by the close proximity?

MS. HOWARD: Yes, we had to take into account some of the -- so if a -- if a -- if a commercial customer's address was such-and-such, Floor 12, they probably weren't a good candidate for participating in this program.

COMMISSIONER FLEMING: Okay. Do you see an

1 improved device that would overcome some of those
2 challenges?
3 **MS. HOWARD**: We have been looking and looking
4 at several devices. I don't want to say the
5 number, but I think upwards of 40 devices have been
6 looked at. There are a number of devices on the
7 market. There are a number of devices that are
8 marketed directly to consumers. Some devices are
9 marketed exclusively to utilities. Most of -- the
10 majority of the devices mount in a customer's
11 breaker box, so they're not actually communicating
12 with the meter; they are sensing the current in the
13 customer's breaker box, and they require
14 installation of the breaker box by an electrician,
15 which of course drives up the cost of the program,
16 drives up the cost of the device. So the challenge
17 has been to find a device that works with the AMR
18 metering, that stays within a cost parameter that
19 makes the program cost-effective. And so that
20 narrows the list down pretty dramatically when you
21 look at that.
22 So it's a technology that, you know, we've
23 found a -- you know, it's sort of, you can find a
24 new device almost every month that you look for
25 one.

COMMISSIONER FLEMING: Uh-huh.

MS. HOWARD: But each one of them have pros and cons, and it's just a matter of looking through what are the pros and cons and finding out what's best suited for the application that we're trying to use it for.

COMMISSIONER FLEMING: Okay. Well, thank you very much for your report today.

CHAIRMAN HOWARD: Commissioners? Commissioner Hall.

COMMISSIONER HALL: Thank you. Thank you, Ms. Howard. I wanted to ask you, when we first approved the programs, you had flexibility and you indicated you all kind of modified some of your programs. Do you see any need for modifications in the future?

MS. HOWARD: I think so. We were pleased to have been granted the flexibility to do that, and we did utilize it, in fact. I'll give you one example. You might remember that, with the Home Energy Check-Up, initially we had proposed that we would do some direct installation of energy efficiency measures, so go into a customer's home and install the CFL bulbs, for instance, or install pipe insulation, for instance. Once we considered

what the number of -- the implications for that would be, would make the visit much longer, for instance, which drives up the cost of the visit. There are also some safety considerations to take into account. When I looked around at my home, there are not a whole lot of bulbs -- and if you look around at your home, there are not a whole lot of bulbs that you can access standing on your own two feet. They will require getting on a ladder of some sort. So we decided that it would be a leave-behind kit, instead of a direct installation. So that's one example.

The other example related to that program is in our application we had proposed that there would be a $25 charge if a customer did not allow the installation of those energy efficiency measures, for whatever reason, if they didn’t want the bulbs, if they didn't want the pipe wrap, pipe insulation, or the water-heater wrap, or whatever, that they would be charged a $25 charge for the visit, essentially, because they hadn't done anything as a result of the visit to necessarily improve their energy efficiency. Once we started talking with our IT department, how you get a $25 charge on somebody's bill in the negative, because they

didn't do something, that proved to be more challenging than it sounded like on paper. And so, and in most instances our experience has been and our thinking at the time was that, "Well, who would turn down something free?" So we thought, well, why invest the energy and the resources in developing a system for charging folks $25 for a charge that they probably will never be -- never incur? So we decided to make that just flat-out free. In probably 99.9 percent of cases, it was going to be free anyway.

So that's an example of some of the things that we've done, where we have utilized or exercised the flexibility that we wanted to have. I see those kinds of things continuing to be necessary. The Energy Information Display is another example where we might decide to use a different device than what we've employed in Phase 1, if we learn something different about the devices that are available. You know, we might decide to deliver it in a different way than we did in the Phase 1. So a lot of things that you kind of discover a lot different in real life than they are in the two paragraphs or three paragraphs on paper.

1 **COMMISSIONER HALL**: Now, you talked about,
2 like, people that get in and don't want to install
3 it. Those are difficult customers. I think I was
4 watching the nightly news one time and this woman
5 had stockpiled incandescent bulbs because she said
6 she didn't want to wait for the CFLs to come on.
7 That split second, she couldn't wait. How do you
8 market to customers like that, that are either
9 older and resistant, or whatever?
10 **MS. HOWARD**: One of the things that I think
11 our approach is going to be is education. So that
12 some of the things that people -- you know, it may
13 be a customer hasn't even experienced that for
14 themselves, but heard that there is a delay in the
15 lights coming on, or they heard that there's, you
16 know, this poor coloring, or that type of thing.
17 So we actually have folks who are out in the field
18 in these retail establishments, doing in-store
19 demonstrations with the lights, showing customers
20 the differences in the lighting color, showing them
21 the differences in the lighting bulbs that are
22 available, so that they know not all CFLs look like
23 the spirally squiggly bulb, that there are
24 specialty bulbs that have a cover over the squiggly
25 part that will look just like any other decorative

lighting fixture that you have in your home. So that's probably the biggest part, is just educating people, kind of debunking some of the myths and things that folks believe that may not necessarily be true.

COMMISSIONER HALL: Okay. And then the display -- I think on page eight-- it really has dollar signs on it.

MS. HOWARD: Yeah.

COMMISSIONER HALL: Is that -- that's really how it looks now?

MS. HOWARD: Yes, it does.

[Reference: *Demand Side Management Programs* PowerPoint Slide 9]

I mean, you can set it up -- you can change the screen so that it shows differently, but the dollar signs are one of the options.

COMMISSIONER HALL: Well, I think the dollar signs would be a good deterrent. Thank you, ma'am.

CHAIRMAN HOWARD: Any other questions?

[No response]

Ms. Howard, I have one. Looking at your Home Energy Check-Up, you mentioned in the slide that you had CFL bulbs, you had water-heater wraps, you had pipe wraps, I believe it was?

1 **MS. HOWARD**: Yes.
2 **CHAIRMAN HOWARD**: Nowhere on your website do
3 you mention this. You also indicated -- you might
4 answer that question. You also didn't indicate it
5 was free. So your website doesn't include those
6 incentives, nor does your website mention this
7 service is free.
8 **MS. HOWARD**: I'm surprised to hear that it
9 doesn't mention on the website that it's free. But
10 it does not mention on the website the Energy
11 Efficiency Kit. One of the things we wanted to do
12 is, kind of getting back to that flexibility, is to
13 maintain that flexibility so that we learn what
14 customers -- what kind of energy efficiency
15 measures our customers -- are they wanting to see
16 and have installed. The Home Energy Check-Up is
17 one of those ones where we feel like we can have a
18 fair amount of flexibility in what those leave-
19 behind items are. There are a number of things
20 that you can do that are low-cost measures that
21 would improve a customer's energy efficiency, so
22 that's one of the reasons why we don't state
23 exactly what those measures will be. There are
24 also some instances where a water-heater wrap would
25 not be appropriate for a customer, so that if

they've either got a fairly new water heater that's already insulated or that it's just not a good application for what they have. So that's mainly the reason why those measures aren't listed.

CHAIRMAN HOWARD: Thank you. Thank you very much, Ms. Howard. Mr. Jackson?

MR. JACKSON: Yes, sir, Mr. Chairman. Let me see if I can get over here [indicating].

[Reference: *Demand Side Management Programs* PowerPoint Slide 29]

Before I get started with my presentation, Mr. Chairman, you had asked a question earlier of Dr. Lynch about the PaCE program. We were able to talk to our PaCE representative and get you those statistics. There are 366 participants, total participants, in the program. And renewable energy that they've purchased to date, of the 366 participants, is 1,600 megawatt-hours. So that's 366 participants and 1,600 megawatt-hours that they've purchased.

CHAIRMAN HOWARD: Okay.

MR. JACKSON: And I think there were a couple of others, like real-time pricing customers on our system. We have approximately seven. And time-of-use residential, we have approximately 90 customers

in the program.

CHAIRMAN HOWARD: Thank you, Mr. Jackson.

MR. JACKSON: Okay. Ms. Howard has spoken to you about an update on the programs. What I'd like to do is give you an overview of the components that make up the DSM rider. And that's what I'll proceed to do right now.

[Reference: *Demand Side Management Programs* PowerPoint Slide 30]

You'll remember from the order that we received last year, the major components of program costs, net lost revenues, shared savings incentives, those are the three components that make up the costs. And then, of course, the denominator is the kilowatt-hour sales. And I'll go into a little bit of detail on each one of these in just a moment.

[Reference: *Demand Side Management Programs* PowerPoint Slide 31]

The program costs, this is a total balance as of the end of the review period. The review period in this case ends in November 2010. We have a regulatory asset on the books where the accountants keep up with the dollars spent on the programs. And you'll see the balance on the next slide that

1 we filed in the application. But we look at that
2 balance at the end of the period. That balance
3 also includes carrying costs at the company's
4 weighted cost of capital. To minimize the impact
5 on the rider, we amortize this balance over five
6 years or include 20 percent of the cost in the
7 calculation or update of the rider. It is subject
8 to ORS audit.
9 And just some examples of the type of costs
10 that go in there: the costs of Ms. Howard's
11 department, people who work for her; implementation
12 costs; rebates and incentives; marketing costs; and
13 any type of consulting fees that we might incur.
14 [Reference: *Demand Side Management*
15 *Programs* PowerPoint Slide 32]
16 This is Exhibit 2 to our petition, and it lays
17 out the calculation and amortization of the program
18 costs. As you can see in the middle column there,
19 you have $1,770,706 as a total cost of the balance
20 in that regulatory asset at the end of November.
21 What we have to do at that point is allocate that
22 to the classes. Typically, we'd like to allocate
23 that balance based on actual costs in the review
24 period. Well, we don't have enough information in
25 the review period at this time to allocate that, so

as the note indicates, we have worked with Ms. Howard's group and we've gotten a projected program cost for the period that we're in now from December of 2010 to November of 2011, and we're using those program costs to allocate the $1,700,000 to the specific classes of customers.

Now as we file again in January of next year, we will have historical information to allocate those costs to classes.

So that's the makeup of the first component of the Demand Side Management rider.

[Reference: *Demand Side Management Programs* PowerPoint Slide 33]

The next component is net lost revenues. This is by far the largest component of the rider, and it is defined as retail revenue losses incurred as a result of lost sales due to implementation of the energy efficiency programs.

I'd like to point out to you, this is the formula that was in the order last year. The formula says we will take all of those lost sales, lost kilowatt-hours, and we will multiply them by the retail rate, less fuel, and less variable O&M costs. And typically, I speak of the overall rate, less fuel, as the margin component, and then we add

1 another component to that, and it's called variable
2 O&M. We also deduct that out.
3 Now, on this component, we true it up at the
4 end of the review period. We'll come back in, and
5 we'll go back and look at actual data and true that
6 information up, and make an adjustment for the next
7 cycle. And of course, this is subject to audit by
8 ORS, and there are no carrying costs associated
9 with this component.
10 [Reference: *Demand Side Management*
11 *Programs* PowerPoint Slide 34]
12 This is the exhibit in the application,
13 Exhibit 3, which breaks this down. And in working
14 with Ms. Howard's group and their model, we come up
15 with the program-related energy savings. These are
16 the lost kilowatt-hour sales that the company is
17 projecting over this review period that we're in
18 now, that will end in November 2011. We've come up
19 with those lost sales, and at that point we
20 multiply them by what we call a net lost revenue
21 factor. That net lost revenue factor by class is
22 an average kilowatt-hour -- cost per kilowatt-hour,
23 less fuel, less variable O&M. So you really have
24 something like margin less variable O&M. And
25 you'll multiply that rate -- looking at the

1 residential, that .08704 -- times the 35,764,000
2 kilowatt-hours, to get the net projected lost
3 revenues for the period from December 2010 to
4 November 2011. And as you can see, it's a total of
5 $6.3 million.
6 Again, we're using the potential study from
7 Ms. Howard's group, which estimates participants in
8 this program, and from that you estimate the
9 participants and the programs they'll participate
10 in; we were able to calculate the projected lost
11 kilowatt-hours. Again, this will be trued up. It
12 is a projection. But when we get to the end of the
13 period and setting the next DSM rider, we will make
14 an adjustment either way, whether it's increased or
15 decreased.
16 [Reference: *Demand Side Management*
17 *Programs* PowerPoint Slide 35]
18 The final cost component is a shared savings
19 incentive, and basically it is 6 percent of the net
20 benefits of each energy efficiency program
21 calculated using the utility cost test. And then
22 in using this component, basically, we're comparing
23 the avoided cost, which is the savings to the
24 program, less any cost of the program, over the
25 life of the program, and doing a net present value

as called for by the utility cost test. Again, with the modeling in our DSM group, we can calculate the net benefits. And, of course, this again -- this one is amortized over five years to mitigate the impact to the rider, and there are no carrying costs, and it's subject to ORS audit. Again, this one will be trued up, because we are using projections to calculate it.

[Reference: *Demand Side Management Programs* PowerPoint Slide 36]

And this is the Exhibit 4 in the application, and basically you can see the net benefits as calculated using the utility cost test. You see the 6 percent of that, which is the total 6 percent shared savings. And then, of course, the final column there is where we take 20 percent or amortize it over five years to get the component that's going to go -- or be included in the rider. Again, I want to stress this will also be trued up. We're estimating it now, but it will be trued up once we come in and file the 2012.

[Reference: *Demand Side Management Programs* PowerPoint Slide 37]

Sales is the denominator component, basically. It -- what sales represented here is our forecast.

We go to our Forecasting Department for our forecasted kilowatt-hour sales by class, and we're able to get that. But there's one little adjustment we have to make to it. As you remember, the large industrial customers, we agreed in the settlement agreement that they could opt out. So, small, medium, and large general service classes have industrial customers, and those customers can opt out, so what we do is we make an adjustment to the projected or forecasted kilowatt-hour sales for those customers, because they will not be there and they will not be charged the DSM rider.

[Reference: *Demand Side Management Programs* PowerPoint Slide 38]

To just pull it all together as a summary, a basic calculation, you have the program costs by class, plus net revenues by class, shared savings incentive by class, to get the total costs by each class of customers. Then you divide through by the class-specific kilowatt-hours, and that will give you the DSM rider that appears on this next slide, which --

[Reference: *Demand Side Management Programs* PowerPoint Slide 39]

-- is also in our application as Exhibit 5,

which shows the calculation down there, "Rate per kilowatt-hour" as the component that we are proposing in our filing.

[Reference: *Demand Side Management Programs* PowerPoint Slide 40]

This slide here shows a summary of what we're currently charging. Residential, for example, is $.26 1,000 kilowatt-hours, and we're proposing $.44 per 1,000 kilowatt-hours, and that's a difference of about an $.18 increase. So, this is what we have going forward.

Some of the contributing factors here, with more -- with the programs out there in the marketplace, we're projecting a higher kilowatt-hour sales loss, and that's the big driver on the residential side. What you're seeing with the other classes, a major component there, other than the lost revenues, is the opt-outs. We have had a number of customers have signed up to opt out of the program -- industrial customers -- and so we have less kilowatt-hours to spread the cost over.

And that's a summary of what I have. Commissioners. I'll be more than happy to answer any questions.

CHAIRMAN HOWARD: Commissioner Mitchell.

1 **COMMISSIONER MITCHELL**: Thank you, Mr.
2 Chairman. How you doing, Mr. Jackson?
3 **MR. JACKSON**: Pretty good.
4 **COMMISSIONER MITCHELL**: I really want to ask
5 you a little bit about your last statement there,
6 the opt-out of the DSM programs. And I believe
7 that number's actually 70 percent of SCE&G's
8 industrial load --
9 **MR. JACKSON**: That's correct.
10 **COMMISSIONER MITCHELL**: -- customers; is that
11 correct?
12 **MR. JACKSON**: It's approximately 70 percent,
13 yes, sir.
14 **COMMISSIONER MITCHELL**: Okay. Do those impact
15 to SCE&G and its customers -- what is the impact to
16 its customers with that many -- that high a
17 percentage asking to opt out, and what does that do
18 to the company's overall picture?
19 **MR. JACKSON**: Well, what -- I don't have an
20 exact calculation of what the rate would've been if
21 they hadn't opted out, Commissioner, but it
22 would've made a significant difference. If you go
23 back to that last slide I had, you can see, I think
24 an overwhelming driver for the increase of going
25 from the current to the proposed for SGS/MGS/LGS is

the opt-out. We have had -- SGS, the total number of customers eligible, eligible to opt out, 49 percent chose to opt out. For the medium general service eligible to opt out, about 35 percent chose to opt out. And on the large general service, those industrial service eligible to opt out, 54 percent chose to opt out.

COMMISSIONER MITCHELL: Okay. So my 70 percent was off?

MR. JACKSON: That all the industry customers within these classes.

COMMISSIONER MITCHELL: I got you, within the classes. And how would that compare to any other company of comparable size with SCE&G? Do you have any stats on that, as far as --

MR. JACKSON: I don't have any stats, but if I had to make a guess at it, I would think it would be equal to us or larger. We may have more that choose to opt out, Commissioner. I am sure they will. If you look at the medium general service and small general service, their percentage is not as large as the large general service --

COMMISSIONER MITCHELL: Well, why would SCE&G have more than any other company?

MR. JACKSON: I'm not saying we'll have more.

I'm just saying more will probably opt out, as they find out and learn more about the DSM rider.

COMMISSIONER MITCHELL: Okay.

MR. JACKSON: If you get to the smaller classes, you have account managers but you have a lot more customers, smaller customers, and they may not have as much conversation with them, whereas with the large general service class, that's where you have your real large industrial customers, and we have specific account managers working with those customers, and believe me, the Kimberly-Clarks of the world, they're opting out.

COMMISSIONER MITCHELL: Okay. Thank you, Mr. Chairman.

COMMISSIONER WHITFIELD: Mr. Chairman.

CHAIRMAN HOWARD: Commissioner Whitfield.

COMMISSIONER WHITFIELD: Thank you, Mr. Chairman. Mr. Jackson, I guess what you're also saying, with this program, since you're amortizing it over five years, you're really -- after this first year, you'll have a better handle on what your actual costs are, be it net lost revenues, shared savings, or costs for Ms. Howard's department. You'll be able to, after this first year -- since we don't have those figures yet --

you'll be able to have more of a handle on it after this year-one, if you will; is that --

MR. JACKSON: We will. As far as the amortization, Commissioner Whitfield, the amortization is what we've agreed on in the settlement agreement, which was approved by the Commission. We agreed on those two components, on the cost and on the net benefits; we agreed to amortize that over five years. So that will require some accounting and bookkeeping to keep up with.

COMMISSIONER WHITFIELD: But after this first true-up, you'll have a much better handle on those?

MR. JACKSON: Oh, absolutely, sir.

COMMISSIONER WHITFIELD: Yes, sir.

MR. JACKSON: Absolutely. We'll have some much better data. And you'll see in some of my slides there where you would see on the medium general service and the large general service, the numbers are the same. We had to split them 50-50 because we don't have a lot of data right there. And we'll true that up as we go forward, once we get more data from the actual period.

COMMISSIONER WHITFIELD: Thank you, Mr. Jackson. That's all I have, Mr. Chairman.

1 **CHAIRMAN HOWARD**: Commissioners, any other
2 questions?
3 [No response]
4 Well, Ms. Howard, Mr. Jackson, thank you very
5 much. You did a great presentation. Also, thanks
6 to Dr. Lynch and Mr. Young.
7 If there's nothing else, Mr. Burgess, have you
8 got any closing remarks or comments you want to
9 make?
10 **MR. BURGESS**: No, sir, Mr. Chairman. Just
11 thank you for your time. We appreciate your
12 questions, and we hope and trust that you find all
13 this information very helpful.
14 **CHAIRMAN HOWARD**: We thank you for the
15 information, and this hearing is adjourned. Thank
16 you for coming.
17 [WHEREUPON, at 1:50 p.m., the proceedings
18 in the above-entitled matter were
19 adjourned.]
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C E R T I F I C A T E

I, Jo Elizabeth M. Wheat, CVR-CM-GNSC, do hereby certify that the foregoing is, to the best of my skill and ability, a true and correct transcript of all the proceedings had in an Allowable Ex Parte Briefing held in the above-captioned matter before the Public Service Commission of South Carolina.

Given under my hand, this the 30th day of April, 2011.

Jo Elizabeth M. Wheat, CVR-CM-GNSC

ATTEST:

Jocelyn G. Boyd,

CHIEF CLERK/ADMINISTRATOR