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S.C. Supreme Court

THE SUPREME COURT OF SOUTH CAROLINA

APPEAL FROM THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
Appellate Case No. 2013-000529

South Carolina Energy Users Committee,

Appellant-Respondent,

v.

**South Carolina Electric & Gas, Office of Regulatory
Staff, Pamela Greenlaw,**

Respondents,

and Sierra Club, is Respondent-Appellant.

RECORD ON APPEAL – VOLUME I

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ORDERS

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2012-203-E - ORDER NO. 2012-884

NOVEMBER 15, 2012

IN RE: Petition of South Carolina Electric & Gas Company for Updates and Revisions to Schedules Related to the Construction of a Nuclear Base Load Generation Facility at Jenkinsville, South Carolina	)	TABLE OF CONTENTS
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BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2012-203-E - ORDER NO. 2012-884

NOVEMBER 15, 2012

IN RE: Petition of South Carolina Electric & Gas	)	ORDER APPROVING
Company for Updates and Revisions to	)	SCE&G'S REQUEST FOR
Schedules Related to the Construction of a	)	MODIFICATION OF
Nuclear Base Load Generation Facility at	)	SCHEDULES
Jenkinsville, South Carolina	)	

I. INTRODUCTION

This matter comes before the Public Service Commission of South Carolina (the "Commission") on the petition of South Carolina Electric & Gas Company ("SCE&G" or the "Company") for an order approving an updated capital cost schedule and updated construction schedule for the construction of two 1,117 net megawatt ("MW") nuclear power units (the "Units") to be located at the V.C. Summer Nuclear Station near Jenkinsville, South Carolina. SCE&G filed the petition in this docket (the "Petition") on May 15, 2012, pursuant to S.C. Code Ann. § 58-33-270(E) (Supp. 2011). Under that provision of the Base Load Review Act (the "BLRA"), a utility "may petition the commission . . . for an order modifying any of the schedules, estimates, findings, class allocation factors, rate designs, or conditions that form part of any base load review order." S.C. Code Ann. § 58-33-270(E). Further, "[t]he commission shall grant the relief requested if, after a hearing, the commission finds . . . that the evidence of record justifies a finding that the changes are not the result of imprudence on the part of the utility." *Id.*

The Petition was preceded by a similar filing, dated February 29, 2012, in Docket No. 2012-90-E. The February 29, 2012, filing predated (i) the issuance of the Combined Operating License (the “COL”) for the Units by the United States Nuclear Regulatory Commission (the “NRC”), (ii) the rescheduling of the substantial completion dates for the Units based on the COL issuance date, and (iii) the resolution of certain claims between SCE&G and the principal contractors for the Units, all of which are discussed in more detail below. By letter dated May 8, 2012, SCE&G withdrew the February 29, 2012, petition in Docket No. 2012-90-E. This allowed the Commission to establish a new hearing and pre-filing dates to allow the parties a full opportunity to review and conduct discovery on this new information. Accordingly, the May 15, 2012, Petition was filed in place of the February 29, 2012, petition.

A. Prior Base Load Review Act (“BLRA”) Orders

In Order No. 2009-104(A), dated March 2, 2009, the Commission approved an initial capital cost schedule and construction schedule for the Units. As approved in that order, the capital cost for the Units was \$4.5 billion in 2007 dollars. With forecasted escalation, this resulted in an estimated cost for the Units at completion of \$6.3 billion in future dollars. The construction schedule approved in Order No. 2009-104(A) anticipated that Unit 2 would be completed by April 1, 2016, and the project as a whole would be completed by January 1, 2019. The South Carolina Energy Users Committee

("SCEUC") appealed Commission Order No. 2009-104(A) to the South Carolina Supreme Court.¹

In April 2009, SCE&G received its initial site-specific, integrated construction schedule from its principal contractors for the Units, Westinghouse Electric Company, LLC and the Shaw Group ("Westinghouse/Shaw"). At that time, SCE&G filed a proceeding under S.C. Code Ann. § 58-33-270(E) (an "update proceeding") for approval of the updated construction schedule for the project and an updated capital cost schedule which reflected the new schedule of cash flows associated with the updated construction schedule. The updated schedules did not alter the total estimated capital cost for the Units of \$4.5 billion in 2007 dollars,² nor did they change the estimated completion dates for the Units. In Order No. 2010-12 dated January 21, 2010, the Commission approved the updated schedules.

On August 9, 2010, the South Carolina Supreme Court issued its decision in SCEUC's appeal of Order No. 2009-104(A), *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, 388 S.C. 486, 697 S.E.2d 587 (2010) (the "Opinion"). In the Opinion, the Court ruled that contingency costs that had not been itemized or designated to specific cost categories were not permitted as a part of approved capital cost schedules under the BLRA. The effect of this decision was to

¹ An appeal from Order No. 2009-104(A) was also taken by Friends of the Earth. *Friends of Earth v. Pub. Serv. Comm'n*, 387 S.C. 360, 692 S.E.2d 910 (2010).

² Unless otherwise noted, all dollar amounts used in this Order reflect the cost associated with SCE&G's 55% share of the ownership of the Units and are expressed in 2007 dollars.

require the removal of \$438.3 million in projected contingency costs from the capital cost schedules approved in Order No. 2009-104(A) and Order No. 2010-12.

In the Opinion, the Supreme Court acknowledged that S.C. Code Ann. § 58-33-270(E) allowed SCE&G to petition the Commission to update the capital cost schedule for the Units as SCE&G identifies and itemizes additional items of cost. The Court noted, “the General Assembly anticipated that construction costs could increase during the life of the project. Under § 58-33-270(E), SCE&G may petition the Commission for an order modifying rate designs.” *South Carolina Energy Users*, 697 S.E.2d at 592–93.

In response to the Opinion, SCE&G filed a petition in November 2010 for approval of an updated capital cost schedule. The Commission approved SCE&G’s updated capital cost schedule in Order No. 2011-345, dated May 16, 2011. In that updated cost schedule, SCE&G—as required by the Opinion—removed its owner’s contingency, i.e., costs that had not been itemized to specific capital cost categories. Where costs could be itemized, the Company requested Commission approval to include those additional cost items in the approved capital cost schedules. Because the amount of the newly itemized costs was less than the amount of the owner’s contingency that was removed from the approved forecasts, the cost schedule approved in Order No. 2011-345 showed a reduction in the total estimated capital cost for the Units from \$4.5 billion to \$4.3 billion. (Tr. at 29.)

B. The Update Petition in This Docket

In the present docket, SCE&G has presented for review and approval additional capital cost and construction schedule updates. The cost updates fall into four categories:

(i) Change Order No. 16 to the Engineering, Procurement and Construction Agreement (the "EPC Contract") for the Units; (ii) owner's cost ("Owner's Cost"); (iii) Transmission cost; and (iv) other change orders to the EPC Contract. (Tr. at 47-48.)

The first category includes costs associated with the February 2012 resolution of four claims made by Westinghouse/Shaw under the EPC Contract. These four claims were resolved as a package to clear the way for SCE&G to issue a full notice to proceed to Westinghouse/Shaw in April 2012. The claims in this category reflect (i) the additional cost of designing, permitting and constructing shield buildings for the Units with increased resistance to aircraft impacts, (ii) the additional costs in rescheduling the construction project as a result of the approximately nine-month delay in issuance of the COL, (iii) the costs associated with changing the design of certain structural modules that will form part of the Units to increase the strength of steel used in them and to improve constructability, and (iv) the costs of responding to unanticipated rock conditions encountered for Unit 2. (Tr. at 47.) SCE&G and Westinghouse/Shaw documented the resolution of those four claims in Change Order No. 16 to the EPC Contract. That change order reflects \$137.5 million of the amount of the requested adjustment in capital cost schedules requested in this proceeding.

In addition, the Petition states that since Order No. 2011-345 was issued, SCE&G has continued to review and revise its forecasts of the Owner's Cost that will be associated with hiring, training and deploying of staff for the project. That staff will oversee construction and testing of the Units and will also operate the Units when completed. The staff will also provide security both during and after construction. The

costs associated with staffing the project include the cost of buildings, warehouse and other facilities to support both the project staff and the permanent staff as well as required furniture, supplies, janitorial services, building maintenance, and equipment, including information technologies systems. These costs are capital costs of the project, not annual costs, and will be incurred over the life of the project. The increased cost reflected in this Owner's Cost category totals \$131.6 million of the requested update. (Tr. at 47-48.)

In addition, the Petition states that SCE&G has revised its estimates of the Transmission cost associated with the project by \$7.9 million. These revisions are based on additional information as to design of the transmission facilities required to route power from the Units to customers and additional information concerning the nature and cost of the lines, substations, equipment upgrades and rights-of-way that will be required. Finally, the Petition reflects the costs associated with three other change orders to the EPC Contract that were negotiated with Westinghouse/Shaw and totaling approximately \$5.9 million. These three change orders were negotiated prior to Change Order No. 16 and dealt with different scopes of work. (Tr. at 48.) The cyber-security cost of approximately \$5.9 million covers review and implementation of equipment and software to overcome vulnerabilities to cyber attack. Also, changes in healthcare costs of \$135,573 were requested, and revisions to the design of the wastewater discharge piping for gravity drainage at a cost of an additional \$8,250 were also requested. Id.

As shown in Chart A, below, taken together these requests total approximately \$283 million:

Chart A

REQUESTED UPDATES TO CONSTRUCTION COST SCHEDULES	
(\$000)	

<u>Item</u>	<u>Cost</u>
Change Order No. 16 (Shield Building, COL Delay, Modules, Rock Condition, etc.)	\$ 137,500
Owner's Cost	\$ 131,625
Transmission Cost	\$ 7,921
Other Change Orders (Cyber Security, Health Care, Wastewater Piping)	\$ 5,905
Total	\$ 282,951

These requested updates in cost raise the cost of the Units by \$18 million, or 0.4%, over the \$4.5 billion forecasted amount approved in the original BLRA order, Order No. 2009-104(A). (Tr. at 261.) However, escalation rates and rates for allowance for funds used during construction ("AFUDC") have been lower than anticipated when originally forecasted in 2008. (Tr. at 30.) As a result, the cost of the Units in future dollars is \$5.8 billion which is \$550 million, or approximately 8%, less than the \$6.3 billion amount forecasted in 2009. (Tr. at 30.)

In the Petition, SCE&G also seeks approval of an updated construction schedule for the Units. This updated schedule delays the completion date of Unit 2 by 11 months

to March 15, 2017, but advances the date for completion of the project as a whole by seven and one-half months to May 15, 2018. (Tr. at 212.)

The original updated capital cost schedule was submitted as Hearing Exhibit No. 6 (CLW-1). A second updated capital cost schedule based on Hearing Exhibit No. 6 (CLW-1), modified according to this Commission's directive in this matter, was submitted by the Company to this Commission. This schedule is attached hereto as **Order Exhibit No. 1**. The updated construction schedule for the project was submitted as Hearing Exhibit No. 1 (SAB-3) and is attached hereto as **Order Exhibit No. 2**.

C. Notice and Interventions

In compliance with S.C. Code Ann. § 58-33-270(E), SCE&G timely provided notice of the Petition in this docket to the South Carolina Office of Regulatory Staff ("ORS"). ORS, pursuant to S.C. Code Ann § 58-4-10 (Supp. 2011), is automatically a party in this docket.

By letter dated May 24, 2012, the Commission's Clerk's Office instructed the Company to publish a Notice of Filing and Hearing in newspapers of general circulation in the area where SCE&G serves retail electric customers (the "Newspaper Notice") by July 3, 2012. The Clerk's Office also instructed SCE&G to provide a copy of the Notice to its retail electric customers by U.S. mail or by electronic mail to customers who have agreed to receive notice by electronic mail (the "Customer Notice"). The Clerk's Office instructed SCE&G to provide proof of newspaper publication by July 18, 2012.

By letter dated May 29, 2012, SCE&G requested an extension of time to July 15, 2012, to provide the Customer Notice. By letter dated May 29, 2012, the Commission

amended its notice requirements for both the Newspaper Notice and the Customer Notice. The revised publication schedule provided for both the Newspaper Notice and the Customer Notice to be accomplished by July 15, 2012, and for Commission receipt of proof of publication and certification of distribution on or before July 24, 2012. On July 13, 2012, the Company timely filed affidavits with the Commission demonstrating that the Newspaper Notice had been duly published in accordance with the Clerk's Office's instructions and certifying that a copy of the Customer Notice had been furnished to each affected customer.

Timely petitions to intervene in this docket were received from Pamela Greenlaw, the Sierra Club, the South Carolina Energy Users Committee ("SCEUC") and Joseph Wojcicki. No other parties sought to intervene in this proceeding.

The petitions of Pamela Greenlaw, the Sierra Club, and SCEUC were not opposed by SCE&G. However, on May 29, 2012, SCE&G filed a Return in Opposition and Objection to the Petition to Intervene ("Return") of Mr. Joseph Wojcicki. On June 4, 2012, Mr. Wojcicki filed a reply to SCE&G's Return. By Order No. 2012-495, dated July 13, 2012, the Commission denied Mr. Wojcicki's petition to intervene. On August 1, 2012, Mr. Wojcicki filed a motion asking the Commission to reconsider the denial of his petition to intervene. By Order No. 2012-622, dated August 15, 2012, the Commission denied Mr. Wojcicki's motion for reconsideration. Mr. Wojcicki did not appeal these orders, but did appear as a public witness to comment on matters at issue in this proceeding.

The Commission convened a public hearing on this matter on October 2-3, 2012, with the Honorable David A. Wright, Chairman, presiding. SCE&G was represented by K. Chad Burgess, Esq., Matthew W. Gissendanner, Esq., and Belton T. Zeigler, Esq. ORS was represented by Courtney Dare Edwards, Esq., Shannon Bowyer Hudson, Esq., and Jeffrey M. Nelson, Esq. The Sierra Club was represented by Robert Guild, Esq., and SCEUC was represented by Scott Elliott, Esq. Pamela Greenlaw proceeded *pro se*.

In support of the Petition, the Company presented the direct testimony of Kevin B. Marsh, Chairman and Chief Executive Officer of SCANA Corporation and SCE&G; Stephen A. Byrne, President for Generation and Transmission of SCE&G; David A. Lavigne, General Manager, Operational Readiness for New Nuclear Deployment; Hubert C. Young, III, Manager of Transmission Planning for SCE&G; and Carlette L. Walker, Vice President for Nuclear Finance Administration.

ORS presented the direct testimony of Allyn H. Powell, Associate Program Manager in the Electric Department of ORS, and Gary C. Jones, P.E., President of Jones Partners, Ltd.

The Sierra Club presented the direct testimony of Dr. Mark Cooper, Director of Energy and Director of Research at the Consumer Federation of America. SCEUC and Ms. Greenlaw presented no witnesses at the hearing.

In response to the testimony of Dr. Cooper, SCE&G presented the rebuttal testimony of Messrs. Marsh and Byrne, and Dr. Joseph M. Lynch, Manager of Resource Planning for SCE&G. The Sierra Club filed surrebuttal testimony of Dr. Cooper in response to SCE&G's rebuttal testimony. In response to Dr. Cooper's surrebuttal

testimony, SCE&G filed a supplemental exhibit to Dr. Lynch's testimony providing the results of an economic study comparing the cost of completing the Units to the cost of pursuing a natural gas resource strategy. The Sierra Club conducted discovery on this comparative economic study prior to the hearing. At the hearing, the Sierra Club presented supplemental rebuttal testimony of Dr. Cooper challenging certain conclusions of Dr. Lynch's study.

D. Bill Issue Raised by Mr. Clements

On October 2, 2012, the Commission held a public night hearing in this proceeding at which 22 members of the public provided comments to the petition of SCE&G. At the public night hearing, Tom Clements, on behalf of the Alliance for Nuclear Accountability, informed the Commission of the billing practice of Georgia Power Company, who is constructing two AP1000 nuclear units in Georgia. As part of his public comments, Mr. Clements provided the Commission with a copy of an electricity bill issued by Georgia Power Company that was included as part of the evidence of record and identified as Hearing Exhibit No. 3. The supplied bill contains a separate line item entitled "Nuclear Construction Cost Recovery." Mr. Clements requests that as part of the ruling in this docket that the Commission issue an order instructing SCE&G to include this same information on SCE&G's electricity bill. For the reasons set forth below, it is not necessary for SCE&G to include this information on its electricity bills.

The information that is required to be included on electricity bills is governed by 26 S.C. Code Ann. Regs. 103-339(2) (Supp. 2011). The form of electricity bills has

received careful consideration by the Commission and the General Assembly. The required information to be included on electricity bills provides a balance between providing customers with information necessary to ensure that each bill is calculated correctly while ensuring that the bill does not become overly complicated or confusing to customers. Each bill must include SCE&G's contact information so that customers who have questions about their bill may raise them with Company representatives. Moreover, issuing an order in this proceeding is not the appropriate manner in which to implement a change to 26 S.C. Code Ann. Regs. 103-339(2). Rather, the appropriate mechanism for such a change would be to initiate a rulemaking proceeding where the Commission receives public comment and the General Assembly has the requisite opportunity to review and approve the regulation.

Mr. Clements' claim that SCE&G's customers are uninformed regarding the cost of the Units is unfounded and not supported in fact. In every proceeding before the Commission regarding the Units, public notice and the opportunity to be heard is provided in the manner required by law and ensures public participation in and awareness of the process. At these public hearings, the public is encouraged to attend and comment. Additionally, for those persons who cannot attend the public hearing, the information presented during the hearing is available to the public for review at the Commission's offices as well as its website <http://dms.psc.sc.gov/>. We find that the current notice and hearing regime in place provides the public with sufficient and adequate notice of the proceedings regarding the Units and that the instant docket is not the appropriate proceeding to consider an alteration to regulations of the Commission. We also find that

26 S.C. Code Ann. Regs. 103-339(2) provides utility customers with sufficient information to be included on their electricity bill, and therefore, decline to initiate a rulemaking proceeding on this matter.

II. STATUTORY STANDARDS AND REQUIRED FINDINGS

S.C. Code Ann. § 58-33-270(E) governs proceedings to update capital cost schedules and construction schedules that have been previously approved under the BLRA. Under this statute, the Commission must grant the relief requested, if after a hearing, the Commission finds that “as to the changes in the schedules, estimates, findings or conditions, that the evidence of record justifies a finding that the changes [in previously approved schedules] are not the result of imprudence on the part of the utility.” S.C. Code Ann. § 58-33-270(E)(1) (Supp. 2011). In addition to S.C. Code Ann. § 58-33-270(E), the Commission is aware that under other provisions of the BLRA, determinations made in the initial BLRA order “may not be challenged or reopened in any subsequent proceeding.” S.C. Code Ann. § 58-33-275(B). In this regard, “[c]hanges in fuel cost will not be considered in conducting any evaluation under this section.” S.C. Code Ann. § 58-33-275(D).

A. The Sierra Club’s Argument

Through the testimony of Dr. Cooper, the Sierra Club argues that the Commission should deny SCE&G’s Petition and find that the additional costs presented by SCE&G for approval in this update proceeding are imprudent. (Tr. at 956.) Specifically, the Sierra Club asserts that because natural gas prices have fallen considerably since 2009, and because energy conservation and alternative generation sources may be becoming

more cost competitive, the Commission should find that it is no longer prudent for SCE&G to continue construction and complete the Units and consequently, that the additional costs are likewise imprudent. (Tr. at 962.) For all practical purposes, the Sierra Club's argument is tantamount to a request that the Commission issue an order instructing SCE&G to terminate the project.³

B. Prior Commission Determinations

Although Dr. Cooper discusses alternative generation and energy efficiency in his testimony, the specific base load generation resource that Dr. Cooper seeks to demonstrate to be preferable to nuclear generation is combined-cycle natural gas generation. (Tr. at 962.) This is not the first time that the Commission has considered the relative merits of a natural gas resource strategy compared to a nuclear resource strategy. In the original BLRA proceeding, Docket No. 2008-196-E, the principal focus of the testimony in support of the Company's application and in opposition to it was the comparison of nuclear and natural gas resource strategies. The studies and other evidence presented in Docket No. 2008-196-E specifically compared the risks and benefits of a nuclear resource strategy to a combined cycle natural gas resource strategy. Those studies considered a number of possible scenarios, including the possibility of lower than anticipated natural gas prices in the future. The testimony presented by Dr.

³ Dr. Cooper did not assert that any fundamental flaw exists or has been discovered in the AP1000 units, in the Jenkinsville site, or in nuclear power generally. To the contrary, the Commission finds that the evidence of record supports the conclusion that nuclear generation continues to be a safe, practical and efficient source of electrical power and that construction of the Units is proceeding in a safe, efficient and satisfactory manner. Most of the major challenges identified in the early stages of the engineering, procurement, construction and permitting for the Units have been overcome. (Tr. at 32.) As to safety and environmental concerns, the design of the Units and the Jenkinsville site have recently passed rigorous reviews by the NRC and other state and federal permitting agencies. (Tr. at 148.)

Cooper in this proceeding is based on the data and analysis presented by SCE&G in Docket No. 2008-196-E. (Tr. at 962-63.) Through sensitivity studies and other approaches, Dr. Cooper has sought to 'update' the 2008 studies by including new data related to gas prices and other factors.

In Order No. 2009-104(A), the Commission carefully reviewed the merits of the natural gas resource strategy compared to the nuclear resource strategy. The Commission entered detailed and specific findings supporting SCE&G's decision to construct the Units rather than choosing to rely primarily on combined cycle natural gas units to meet its projected base load generation needs. In its review of Order No. 2009-104(A), the South Carolina Supreme Court found that "based on the overwhelming amount of evidence in the record, the Commission's determination that SCE&G considered all forms of viable energy generation, and concluded that nuclear energy was the least costly alternative source, is supported by substantial evidence." *Friends of Earth v. Pub. Serv. Comm'n*, 387 S.C. 360, 369, 692 S.E.2d 910, 915 (2010).

C. Policies and Procedures and Key Provisions of the BLRA

The Sierra Club's arguments raise important questions about practice under the BLRA. The Sierra Club argues that the issue of whether the Commission should approve increasing capital forecasts for the Units requires the Commission to determine whether it is prudent to continue the construction of the Units at all. (Tr. at 953.) Therefore, as a condition of approval of the updated capital cost schedules at issue here, the Sierra Club ultimately seeks to reopen the issue of whether nuclear generating resources remain the appropriate choice for SCE&G.

For its part, SCE&G asserts that the arguments and evidence presented by the Sierra Club in this proceeding constitute an attempt to reopen the determinations made in Order No. 2009-104(A) concerning the appropriateness of choosing a nuclear generation resource strategy as compared to a natural gas resource strategy, which on its face appears to be contrary to S.C. Code Ann. § 58-33-275(B). SCE&G takes the position that under S.C. Code Ann. § 58-33-270(E), the operative question before the Commission in an update proceeding is whether “as to the *changes* in the schedules [presented by SCE&G] . . . the evidence of record justifies a finding that the *changes* are not the result of imprudence on the part of the utility.” S.C. Code Ann. § 58-33-270(E) (Supp. 2011) (emphasis supplied). That is, SCE&G contends that the plain language of the statute focuses the Commission’s review on the prudence of the specific changes to the cost and construction schedules that are being proposed in this docket. (Tr. at 76.)

In weighing these arguments, the Commission notes that the BLRA was intended to cure a specific problem under the prior statutory and regulatory structure. Before adoption of the BLRA, a utility’s decision to build a base load generating plant was subject to relitigation if parties brought prudence challenges after the utility had committed to major construction work on the plant. The possibility of prudence challenges while construction was underway increased the risks of these projects as well as the costs and difficulty of financing them. In response, the General Assembly sought to mitigate such uncertainty by providing for a comprehensive, fully litigated and binding prudence review before major construction of a base load generating facility begins. The BLRA order related to the Units, Order No. 2009-104(A), is the result of such a process.

It involved weeks of hearings, over 20 witnesses, a transcript that is more than a thousand pages long and rulings that have been the subject of two appeals to the South Carolina Supreme Court.

S.C. Code Ann. § 58-33-275(A) establishes the final and binding nature of BLRA orders as a matter of law. Furthermore, S.C. Code Ann. § 58-33-275(B) states that the determinations made in such orders “may not be challenged or reopened in any subsequent proceeding.” Finally, S.C. Code Ann. § 58-33-275(D) recognizes the specific danger that would be posed to this regulatory scheme if changes in fuel costs could result in a reassessment of the prudence of base load units during construction. Under S.C. Code Ann. § 58-33-275(D), “[c]hanges in fuel costs will not be considered in conducting any evaluation under this section.” Changes in fuel costs are the principal factual foundation of the Sierra Club’s position in this matter.

The approach to the BLRA that is proposed by the Sierra Club would inject prudence challenges back into the process for building base load generating facilities whenever an update proceeding is required. The cost schedules approved under the BLRA do not include owner’s contingency, and for that reason, update proceedings will now be necessary to review and approve future adjustments in cost forecasts. See *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm’n*, 388 S.C. 486, 697 S.E.2d 587 (2010). Update proceedings are likely to be a routine part of administering BLRA projects going forward (including future projects proposed by other electric utilities), such that under the Sierra Club’s argument, the prudence of the decision to build the plant will be open to repeated relitigation during the construction period if a

utility seeks to preserve the benefits of the BLRA for its project. Reopening the initial prudence determinations each time a utility is required to make an update filing would create an outcome that the BLRA was intended to prevent and would defeat the principal legislative purpose in adopting the statute.

In any event, although not required by the terms of the BLRA, the record in this proceeding has provided the Commission with sufficient evidence on which to examine and evaluate the positions of SCE&G and the Sierra Club on the factual issue of whether continuing with construction of the Units is prudent and whether the additional costs and schedule changes are prudent. Based on the evidence of record before us, the Commission concludes that the construction of the Units should continue and that the additional costs and schedule changes are not the result of imprudence on the part of SCE&G, though the Commission approves only the portion of cyber-security cost that is known and quantifiable (Phase I) while deferring the remainder (Phase II).⁴

III. REVIEW OF THE EVIDENCE AND EVIDENTIARY CONCLUSIONS

The Commission has reviewed the facts and evidence of record and reaches the following conclusions:

A. Prudence of Completing the Units

The factual record concerning the Sierra Club's challenge to the prudence of completing the Units is contained in the direct and rebuttal testimony, as supplemented at the hearing, of its witness Dr. Cooper, and the responses to it in the

⁴ While the Commission has here addressed the prudence of the continuation of the construction of the Units, based on its ruling herein, if this issue is raised in future cases, the Commission would be willing to entertain appropriate motions *in limine* or other procedural motions regarding this issue.

rebuttal testimony by Mr. Marsh, Mr. Byrne, and Dr. Lynch, and the comparative economic analysis conducted by Dr. Lynch, Exhibit No. 9 (JML-4).

1. Dr. Cooper's Factor Analysis

Dr. Cooper's analysis of the prudence of continuing to construct the Units focused on the comparative cost of natural gas generation and nuclear generation given current natural gas prices. (Tr. at 962.) Dr. Cooper based his study on the data and analysis presented by Dr. Lynch in Docket No. 2008-196-E (the "2008 Studies"). (Tr. at 963; Hr'g Ex. 10 (MNC-4)). He sought to recalculate its results based on changes in one factor, specifically, the recent decline in natural gas prices.

In the 2008 Studies, Dr. Lynch showed that at the baseline natural gas price forecast, the advantage of the nuclear resource strategy over the natural gas resource strategy was \$15 million dollars per year levelized over forty years. (Tr. at 963.) In other words, the nuclear resource strategy was the least costly resource and one scenario quantified that this lower cost resulted in levelized savings to customers of \$15 million per year. *See* Commission Order No 2009-104(A) and *Friends of Earth v. Pub. Serv. Comm'n*, 387 S.C. 360, 369, 692 S.E.2d 910, 915 (2010). Dr. Lynch also provided a sensitivity analysis, which demonstrated that if natural gas prices were higher than forecasted by 25%, the comparative benefit of the nuclear resource strategy increased over the gas resource strategy from \$15 million to \$53.4 million per year. (*Id.*)

Dr. Cooper determined that in mid-2012, the current Energy Information Administration ("EIA") natural gas cost forecasts were 62% below the base line forecast

used in Dr. Lynch's 2008 Studies. (*Id.*) Based on the relationship between these numbers, he computed that a 62% decline in natural gas price forecasts would cause a shift of approximately \$132 million in the relative economics of the nuclear and natural gas resource strategies as calculated in the 2008 Studies. (*Id.*) Since the nuclear resource strategy started with a \$15 million advantage, Dr. Cooper reduced the \$132 million savings he calculated by that amount. This resulted in a calculation showing a net advantage to the natural gas resource strategy of \$115 million. (*Id.*)

Dr. Cooper then increased his estimated savings from natural gas by assuming that there would be no cost associated with carbon ("CO₂") emissions. Dr. Lynch's 2008 studies had shown that assuming zero CO₂ cost, the natural gas resource strategy had an advantage over the nuclear resource strategy of \$87 million per year. (Tr. at 964.) Dr. Cooper added this amount to his \$115 million calculation to conclude that the levelized cost of the natural gas resource strategy over the nuclear resource strategy was in excess of \$200 million. (*Id.*) He then multiplied this amount by 40 to reflect the forty-year planning horizon for Dr. Lynch's study. Based on this calculation, he determined that the natural gas resource strategy had a cumulative \$8 billion advantage over nuclear.⁵ (*Id.*)

⁵ Dr. Cooper claimed that SCE&G did not factor certain risks into its original cost projections that were approved under the BLRA even though these risks should have been evident at that time. (Tr. at 972.) The risks that he believes SCE&G should have originally factored into its cost projections include difficulties in staffing the Units, supply chain issues, delays in regulatory approval, and the possibility that regulations would change during the construction of the Units. (Tr. at 970-71.) According to Dr. Cooper, SCE&G should have been aware of these risks and factored the cost associated with them into the original cost projections. (Tr. at 972.) He asserts that the failure of SCE&G to consider these risks amounted to its presenting the Commission with a "low ball estimate" of the cost of the Units. Had the Commission been presented with the actual cost of the Units, including the \$450 million that he claims amount to cost overruns, it may have arrived at a different decision regarding their prudence. (Tr. at 972.)

The Company rebutted these claims in the testimony of Mr. Byrne. Mr. Byrne points out that the cost forecasts and the EPC Contract were independently audited by consulting firms retained by ORS. (Tr. at 269.) The experts within those consulting firms had extensive experience with forecasting costs related

In summary and according to Dr. Cooper, the natural gas resource strategy is now the least costly resource.

2. Dr. Lynch's Alternative Factor Analysis

SCE&G's rebuttal testimony challenged Dr. Cooper's conclusions on several points. First, Dr. Lynch prepared an alternative analysis focusing on two factors related to the current cost of completing the Units. (Tr. at 903-04.) One factor was the reduction in the cost of the Units due to lower escalation and AFUDC rates than were anticipated in 2008. Lower escalation and AFUDC costs have reduced the forecasted cost of the Units in future dollars by \$551 million. The other factor Dr. Lynch analyzed was that 25% of the current costs of the Units have already been spent and only 75% is required to be spent to complete them. In comparing the cost of completing the Units versus switching to a natural gas resource strategy, Dr. Lynch pointed out that the analysis must take into account that a substantial part of the cost of building the Units has been spent. (Tr. at 890, 904.)

In his rebuttal testimony, Dr. Lynch quantified the impact of these two factors using a standard tool employed in utility planning analyses, the levelized carrying cost for investment. This represents the annual cost that must be charged to customers for each dollar spent on a utility investment to fund depreciation, taxes, the cost of capital (debt and equity) and insurance related to that investment. In this case, Dr. Lynch computed

to major electric generation projects, including nuclear projects. (*Id.*) Those experts would also have been familiar with the risks inherent in nuclear construction. These independent reviews of the cost forecasts and the EPC Contract found nothing to indicate that SCE&G's cost estimates were inaccurate. The Commission finds Mr. Byrne's testimony credible and does not find that the evidence on the record supports the "low ball" allegation.

the specific carrying cost for investment in the Units taking into account the items mentioned above. He did so on a levelized basis over the 40-year planning horizon. As Dr. Lynch testified, the levelized carrying cost factor for investment in the Units is 16%, *i.e.*, for each dollar invested, SCE&G must collect \$0.16 per year over the planning horizon. (Tr. at 903.) Applying this factor to the \$551 million reduction in the cost of the Units, the annualized savings of the nuclear strategy increases by \$88 million (\$551 million * 0.16%). (Tr. at 904.)

Dr. Lynch also testified that because, as of June 30, 2012, approximately 25% of the currently forecasted cost of the Units has been spent, the cost to complete the Units is reduced by approximately \$1.4 billion. (Tr. at 892.) As a result, for planning purposes, the levelized going-forward cost of pursuing the nuclear strategy has been reduced by the additional amount of \$230 million per year, which is the carrying cost that would be incurred on that \$1.4 billion.⁶ Accordingly, Dr. Lynch testified that these two factors alone reduced the cost of the nuclear strategy by a total of \$318 million on an annualized basis. This amount far exceeds the amounts that Dr. Cooper calculated to be the savings that result either from low natural gas cost forecasts alone or from the low natural gas and zero CO₂ costs scenarios combined. (Tr. at 890-92.)

Dr. Lynch further testified that in planning studies, the appropriate way to reflect levelized savings as a lump sum is through a present value calculation, not by simply multiplying the levelized annual cost by the number of years in the study as Dr. Cooper calculated. (Tr. at 892.) Calculating the net present values of the savings discussed

⁶ \$5,762 million * 0.16 * 0.25, where \$5,762 million is the current cost of the Units, 25% is the amount that has been spent and 16% is the levelized carrying cost of nuclear investment.

above, Dr. Lynch presented a chart, which is produced below, showing the relative impact of the factors identified in the comparative analyses presented in 2008.⁷

Chart B

**Dr. Cooper's Adjustments to
Natural Gas Strategy Costs
(reduced costs, in millions)**

Low Gas Cost Alone

Levelized Per Year	\$115
Accumulated	\$4,000
Present Value	\$1,400

**SCE&G's Adjustments to
Nuclear Strategy Costs
(reduced costs, in millions)**

Low Gas Cost & No CO₂ Cost

Levelized Per Year	\$200
Accumulated	\$8,000
Present Value	\$2,400

Going-Forward Cost

Levelized Per Year	\$318
Accumulated	Not Computed
Present Value	\$3,900

(Tr. at 910.)

3. Natural Gas Price Volatility

Dr. Lynch also faulted Dr. Cooper's analysis on the basis of its reliance on natural gas price forecasts that are inherently unreliable:

Planners, if they are prudent, do not put much confidence in anyone's projection of natural gas prices. That is why almost all resource planning studies involve scenario planning and sensitivity analysis around the most uncertain drivers of cost. The price of fossil fuels is one of the most volatile and uncertain drivers of energy costs.

⁷ On page 6 of Dr. Cooper's surrebuttal testimony, he alleges that the Company has "double discounted [his] calculation of natural gas savings" without providing sufficient additional detail to validate this claim. (Tr. at 981.) From the Commission's review of the figures presented by the Company, the Commission finds that the calculations provided by SCE&G appear to be correctly computed and do not involve double counting. Based on the information provided by Dr. Cooper, the Commission is constrained to find this argument without factual basis or merit.

(Tr. at 898.) Dr. Lynch provided data from EIA showing that EIA acknowledges that its forecasts are almost always in error, whether too high or too low. In addition, EIA has computed the 95% confidence interval around its forecast of gas prices through 2013. Within that confidence interval, natural gas prices could be as high as \$7.76 per MMBTU on December 31, 2013, or as low as \$2.11, with the expected price being \$3.63. This means that in mid-2012, EIA recognized that by December 2013, there was an equal probability of natural gas prices being 214% higher than the forecasted price as there was of them being 42% lower. (Tr. at 898-99.)

As Mr. Marsh testified, “[i]f there is anything that I have learned in my more than 30 years of experience in this industry, it is that current gas price forecasts—whatever they are—will change. The projections on which Dr. Cooper relies were different four years ago, and in all likelihood will be different four years from now.” (Tr. at 86.)

Dr. Lynch further identified a number of “forces at work in the economy that could cause today’s forecasts of future gas prices to prove inaccurate.” (Tr. at 901.) Those factors include the increasing substitution of natural gas for coal as an electric generation fuel, increased exports of liquefied natural gas in response to a wide disparity between domestic U.S. natural gas prices and international energy prices, and the expansion in the United States of industries that use a high volume of natural gas for fuel and feedstock. (Tr. at 900.)

Natural gas prices are low today because of a new technology known as hydrological fracturing, or fracking. (Tr. at 899.) Over the past two years, fracking has

opened up an abundance of new gas supply that has driven domestic natural gas prices down to levels that are now much lower than comparable prices internationally.

Fracking, however, is under increasing environmental attack by certain special interest groups, including the Sierra Club, that wish to limit its use. (Tr. at 78, 901-02.) In addition, recent Environmental Protection Administration ("EPA") regulations related to CO₂ emissions have made it economically impossible to build coal plants to meet the demand for electricity. (Tr. at 901.) Dr. Lynch testified that apart from nuclear "there is now only one type of dispatchable base load/intermediate load generation resource that can be built in most of the United States. That is combined-cycle gas generation." (Tr. at 902.) This development will "create the need for new pipeline capacity to deliver gas in the required volumes, which involves construction and permitting costs and risks, which can lead to higher costs. Of course, if you burn gas, you emit carbon, so another risk of gas generation is the risk that CO₂ costs will be imposed directly on gas as a fuel." (Tr. at 901.)

Based on the foregoing, Dr. Lynch testified that "there is a great deal of uncertainty in natural gas prices and in their projection. Prudent resource planning decisions cannot be made based on a single scenario of natural gas price projections." (Tr. at 902.) Dr. Lynch concluded:

I have much more confidence in the \$318 million adjustment [that Dr. Lynch calculated] than the \$115 million [in savings that Dr. Cooper calculated]. More than two-thirds of the cost left to be spent under the EPC contract are fixed or subject to fixed escalation rates. Of course, the 25% of the cost of the Units that has already been spent is fully known and measurable. On the other hand, I have already discussed the volatility and uncertainty of prices in the natural gas market. The \$115 million adjustment to the natural gas generation strategy is based on an

assumption of low gas prices over the next 40 years which is very uncertain. All indications are that the uncertainty of the gas price forecast is much greater than the uncertainty surrounding the cost of completing the construction cost of the Units.

(Tr. at 906.)

4. Mitigating Risk Through a Balanced Generation Portfolio

SCE&G's witnesses also criticized Dr. Cooper's approach for relying entirely on a single factor/single scenario cost analysis:

Experienced planners formulate generation plans by evaluating multiple sets of price and regulatory assumptions that encompass a broad range of possible conditions that the system may encounter over the 40-year planning horizon. No one scenario dictates the selection decision, as Dr. Cooper's testimony would suggest. Instead, the modeling results for many different scenarios inform the evaluation. The goal is to determine what generation choices lead to the most flexible, resilient and robust mix of generation resources. The mix we seek is the one that can perform best under the widest range of possible market, operating and regulatory conditions, and that preserves for SCE&G and its customers the best options for dealing with future uncertainty.

(Tr. at 82.) The reason for this approach is that "fossil fuel markets, and now environmental policies as to fossil fuel, are inherently volatile and cannot be predicted with certainty. Market conditions and regulatory requirements will change in ways that cannot be predicted over the 40-year plus period that fossil plants will be in service." (Tr. at 80.) Given that volatility:

[i]t is a fundamental mistake to believe that sound base load planning decisions can be made simply by modeling outcomes based upon current projections of future fossil fuel costs or regulatory conditions. Such one-dimensional analysis does not take into consideration the dynamic energy markets in which we operate or our inability to know with certainty what market, regulatory and operating conditions will be decades in the future.

In this context, one-dimensional analyses are dangerous and expose our customers to risk.

(Tr. at 80.) Mr. Marsh testified that analytical modeling is “not the end of the resource selection process, but the beginning.” (Tr. at 84.) The question to be answered is: “Which type of generation would contribute to a generation portfolio that could best respond to the widest range of potential conditions in fuel markets, operating conditions and environmental costs over the coming decades and give SCE&G the most options to respond to unanticipated conditions in the future?” (Tr. at 84-85.) That decision is not determined by any “single analysis or set of assumptions as to future natural gas costs, operating conditions or environmental costs” Tr. at 85.) Instead, it is “informed by information about how the different configurations of the system would perform across multiple sets of assumptions, combined with the business judgment and the collective wisdom of an experienced team of planners, engineers and executives.” (Tr. at 85.)

Referring to the initial decision to construct the Units, Mr. Marsh stated:

We concluded then, and still believe today, that adding nuclear generation creates a system that can perform best in the widest range of conditions over the coming decades. As I mentioned in my direct testimony in this docket, by adding nuclear generation, our generation mix in 2019 will be 27% coal, 28% natural gas, 31% nuclear and 14% hydro/biomass. This will give us the flexibility to switch between coal and gas generation as conditions warrant. It will mean that in 2019, we will have reduced our carbon emissions by 54% compared to their levels in 2005, giving us a secure position if carbon taxes, cap and trade systems, or other regulatory mechanisms impose costs on carbon emissions. Our balanced generation portfolio will also mean that as we go forward from 2019, we would have the option to add additional natural gas-fired generation to our system without fear of becoming overly reliant on natural gas as a fuel. We can also add resources like solar, wind or DSM where feasible knowing that standing behind them is a secure foundation of reliable generation.

(Tr. at 85-86.) By contrast, “[i]f the Commission were to accept Dr. Cooper’s recommendation, then in 2019, SCE&G’s customers would be relying on a generating system that generates 47% of its electricity from natural gas, which the Sierra Club opposes, and 76% from fossil fuels, which they also oppose.”⁸ (Tr. at 78.)

Mr. Marsh further testified, “More than 660,000 customers depend on SCE&G for reliable, efficient electric service Making base load selection decisions on one-dimensional analyses like Dr. Cooper’s is not how SCE&G can best fulfill its future service obligations to its customers.” (Tr. at 80-81.)

5. Dr. Lynch’s Comparative Economic Study

In his surrebuttal testimony, Dr. Cooper insisted that “the Commission needs a new economic analysis of the going forward costs to ascertain whether continuing the project is prudent.” (Tr. at 979.) In response, on September 27, 2012, SCE&G provided to the parties Dr. Lynch’s “Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy” (the “2012 Study”). It was entered into evidence, without objection, as a supplemental exhibit to the rebuttal testimony of Dr. Lynch (Hr’g Ex. 9 (JML-4)). After the 2012 Study was filed, the Sierra Club, on September 28, 2012, served SCE&G with discovery demands related to it.

⁸ Mr. Marsh also testified that Dr. Cooper’s testimony contradicts the position that the Sierra Club takes outside of this proceeding, i.e., citing the following statement from the Sierra Club: *“Fossil fuels have no part in America’s energy future—coal, oil and natural gas are literally poisoning us. The emergence of natural gas as a significant part of our energy mix is particularly frightening because it dangerously postpones investment in clean energy at a time when we should be doubling down on wind, solar and energy efficiency.”* *Beyond Natural Gas*, SIERRA CLUB, <http://content.sierraclub.org/naturalgas> (last visited August 23, 2012). Tr. at 77.

SCE&G responded to those discovery demands on September 30, 2012, in advance of the hearing.

The 2012 Study presented multi-factor scenario analyses that used the same models and approach that were used in performing the 2008 Studies. In the 2012 Study, relevant inputs were updated to reflect the current cost of completing the Units, the current capital cost of combined cycle generation, and current natural gas price forecasts based on data provided by the economic forecasting firm which SCE&G retained for that purpose (these forecasts of natural gas prices were somewhat lower than Dr. Cooper's EIA forecasts of natural gas prices). The 2012 Study was also based on current nuclear fuel cost forecasts, the Company's current cost of capital and capital structure, new substantial completion dates for the Units, the current value of production tax credits related to the Units, and current forecasts of future electric loads as used in preparing SCE&G's Integrated Resource Plan as submitted to the Commission each year. In preparing the 2012 Study, SCE&G also calculated the estimated cost of terminating the EPC Contract and subcontracts under it, and decommissioning the site. As an offset to those costs, SCE&G estimated the value it would expect to receive from selling to third parties the equipment, material and work in progress on hand. The cost to SCE&G of cancellation, net of sales and salvage, was \$543 million.⁹ (Hr'g Ex. 9.)

The 2012 Study compared the economics of completing the Units as planned in 2017 and 2018 versus abandoning construction and instead constructing two 614 MW combined-cycle gas units, providing the net generating capacity identical to the nuclear

⁹ The total amount was \$988 million. SCE&G would seek to recover 45% of that amount from Santee Cooper under their agreements concerning joint ownership of the project.

Units. To ensure comparability in the analysis, the 2012 Study assumed that the combined-cycle gas units would come on-line on the same dates as the nuclear Units being replaced. (*Id.* at 1.)

As Dr. Lynch explains, the 2012 Study assumed that normal payments under the EPC Contract would cease on January 1, 2013. The amount spent at that time would be approximately \$2 billion. Under the natural gas resource strategy, the \$2 billion spent on the abandoned nuclear construction and the \$543 million in net abandonment costs are recovered over 40 years under the terms of S.C. Code Ann. § 58-33-280(K) (Supp. 2011). (*Id.* at 2.) The nuclear resource strategy reflects the full cost of the Units of \$5.8 billion being recovered over the life of the plants.

The 2012 Study compares the revenue requirements of the nuclear and natural gas resource strategies under 27 different scenarios applying three different sets of variables. One set of variables was based upon three natural gas price forecasts: the SCE&G forecast; the SCE&G forecast plus 50%; and the SCE&G forecast plus 100%. The study considered three scenarios concerning costs related to carbon emissions effective in 2017: no cost per ton of CO₂; \$15 per ton of CO₂; and \$30 per ton of CO₂. Scenarios were run to test the sensitivity of the analysis to variations in future electric demands. The study considered high load, base load and low load forecasts. The high electric load forecast was 5% above the base electric load forecast, and the low electric load forecast was 5% below. (*Id.* at 5-8.)

The 2012 Study demonstrated that in each of the 27 scenarios, completing the Units represented the lower cost alternative than switching to a natural gas resource

strategy. In the base electric load scenario,¹⁰ the savings varied from \$26 million per year, applying base gas prices and no cost for CO₂ emissions, to \$407 million per year in the high gas scenario and a \$30 per ton CO₂ price. (*Id.* at 9.)

Chart C

	Benefit of Nuclear Strategy over the Gas Strategy		
	Base Electric Load Scenario		
	Levelized Present Worth of Change in Revenue Requirements		
	<u>Over 40 Years (\$MM)</u>		
	<u>Base Gas</u>	<u>50% Higher Gas</u>	<u>100% Higher Gas</u>
\$0 CO ₂ Price	\$26	\$144	\$262
\$15 CO ₂ Price	\$102	\$215	\$335
\$30 CO ₂ Price	\$175	\$290	\$407

The 2012 Study found that the most reasonable scenario for planning purposes was the scenario applying base electric load, 50% higher gas prices and a \$30 per ton CO₂ price. Dr. Lynch found this scenario to be the most reasonable for two reasons. First, the moderately higher gas price reflected the fact that the SCE&G forecast was very low when compared to the EIA forecast, and the greater probability is that future gas prices will be higher than forecasted, not lower. The choice of the \$30 per ton CO₂ price reflected that this price is lower than the price used by the Federal Government in assessing the social cost of CO₂ emissions when evaluating the net impact of new regulatory action. (Tr. at 4-5.) In addition, costs substantially below that level would be insufficient to drive behavior in a way that would effectively limit emissions. In the base electric load, 50% higher gas prices and \$30 per ton CO₂ price scenario, the savings from

¹⁰ As Dr. Lynch testified, the 2012 Study results demonstrated that the analysis was not materially sensitive to what electric load forecast assumptions were made. The variation between the electric load scenarios was minimal.

completing the Units and not switching to a gas natural resource strategy is \$290 million per year.

6. Evaluation and Conclusions

The Commission finds that the evidence presented by SCE&G amply establishes the prudence of continued investment in the project. The Commission finds that Dr. Lynch's initial factor analysis and the subsequent 2012 Study are both credible and reliable evidence sufficient to support prudence of the project in all respects and meet all relevant and material points raised in Dr. Cooper's testimony.

The Commission further finds, as Dr. Lynch testified (Tr. at 930-33), that any reasonably foreseeable changes in the capital cost of the Units would not change the outcome of his analysis¹¹ or the conclusion that the nuclear resource strategy remains the most beneficial and prudent strategy for the Company under current gas price forecasts and other conditions. The Commission finds, as Mr. Marsh testified (Tr. at 82-83), that decisions concerning the construction of new base load generation plants should be made with the goal of creating a diverse and balanced generation portfolio that can perform well under multiple conditions concerning fuel costs and environmental regulations. For that reason, in establishing prudence and making siting decisions for base load units, undue weight should not be placed on any single scenario or analysis related to fuel prices or environmental costs.

¹¹ In rough terms, if a decrease in the capital cost of the Units of \$551 million results in an \$88 million change in the levelized annual savings, then all other things being equal, it would take an increase in the Units' capital cost of over \$1.8 billion to offset the \$290 million in benefits Dr. Lynch calculated. (Tr. at 904).

In addition, the Commission finds that prudence in base load selection decisions should be assessed recognizing that the benefits of fuel diversity and the flexibility to respond to future environmental regulations are important factors to be considered. The evidence presented in this docket demonstrates that additional nuclear generation will bring considerable benefits of this type to SCE&G's generation portfolio and that those benefits exist across a diverse range of possible scenarios for fuel costs and environmental regulations. Furthermore, the record here amply demonstrates that the potential risks of relying on natural gas price forecasts remaining as low as they are today are significant. For all these reasons, the Commission finds that the Company has made an affirmative and sufficient demonstration of the prudence of its nuclear construction program. (*See, e.g.*, Tr. at 899.) In any event, as noted above, while this finding is justified by the evidence, this Commission also finds that the BLRA does not require that this issue be relitigated once the initial finding has been made.

B. Update to BLRA Approved Cost Schedules

In its Petition, SCE&G asked for updates to its cost schedules in four major categories, each of which is discussed below:

1. Change Order No. 16

The Company is seeking Commission approval of the costs associated with Change Order No. 16, which represents \$137.5 million, or slightly less than half of the total change in costs requested in this proceeding. (Tr. at 187, 195.)

(a) Shield Building Redesign

The shield building design for the Westinghouse AP1000 Unit was originally approved in a Safety Evaluation Report by the NRC in 2004. It incorporated steel reinforced concrete walls and a steel reinforced concrete roof. (Tr. 1056-59.) At the time that the EPC Contract was executed the NRC had issued a draft rule for comment that would require shield buildings to be designed with greater resistance to aircraft impacts than had been required when the AP1000 reactor received its design certification in 2004. However, at the time the EPC Contract was executed, the draft rule and its requirements had not been finalized or issued. (Tr. at 192.)

To comply with the requirements of the rule as proposed, Westinghouse began work to redesign the AP1000 shield building. Westinghouse originally planned to increase the strength of the design by increasing the thickness of the shield building's reinforced steel concrete walls and roof. However, the initial work showed that meeting the requirements of the rule would require increasing the thickness of the shield building walls to an extent that would decrease the interior volume of the building to an impractical degree. Westinghouse's solution was to select a design that included a continuous shell of welded steel plates on the inside and outside of the shield building. This is referred to as a "steel composite design." Concrete would then be poured between the walls of the steel plates. The inner and outer steel shells provide strength and durability to the concrete and shear strength via metal studs, called Nelson Studs, that are anchored to the inner and outer steel shells and protrude into the space where the concrete is poured. (Tr. at 192-93.)

In addition, the new design required revisions to the structural connection between the floor support for the building (the “base mat”) and the shield building walls, as well as between the shield building and the auxiliary building. Design changes were also needed for the air inlets and the tension ring which are located at the transition between the shield building wall and the roof. (Tr. at 193.)

Steel composite design of this sort had been used in other countries, but had not been used for similar applications in the United States. For that reason, design codes certifying the strength and performance of this type of construction had not been issued in this country. As a result, the NRC required Westinghouse to conduct extensive testing to verify the performance of this design. The NRC required repeated iterations of testing before certifying the design. Difficulty with the testing and certification of this design was an important factor in Westinghouse’s inability to obtain approval of the revised design within the anticipated schedule. (Tr. at 196.)

In 2011, Westinghouse/Shaw asserted a claim under the EPC Contract for the additional costs associated with the designing, testing and construction of the new shield building design. Westinghouse/Shaw did so based on a provision of the EPC Contract that provides for change orders where cost increases are due to “uncontrollable circumstances.” Under the EPC Contract, “uncontrollable circumstances” can mean, among other things, an order or other action by a governmental authority that is not the result of the negligent or willful acts of the party claiming uncontrollable circumstances. Westinghouse/Shaw claimed that the aircraft impact rule, and its interpretation by the

NRC, was a governmental order or action that fell within the definition of uncontrollable circumstances. SCE&G challenged this claim. (Tr. at 194.)

(b) COL Delay

When the EPC Contract was executed, SCE&G and Westinghouse/Shaw anticipated that the NRC would issue the COL for the Units in mid-2011, slightly more than three years after the initial COL application was filed. As Mr. Byrne testified, that expectation was based on information provided to SCE&G and the public by the NRC.¹² This information was accepted by the parties to the EPC Contract as a reasonable basis for establishing the construction and equipment delivery schedules included in the EPC Contract. At that time, the AP1000 design had been approved for several years. The shield building redesign related to aircraft impact resistance had not begun. SCE&G had conducted nuclear operations successfully on the Jenkinsville site for decades, and the environmental, geological, and other conditions related to the site were well documented and understood. (Tr. at 199.)

¹² After the close of evidence at the hearing in this matter, Intervenor Pamela Greenlaw, as a *pro se* litigant, sought to compel SCE&G to provide additional discovery responses related to the establishment in the EPC Contract of the date of mid-2011 as the anticipated date for COL issuance. At the Commission's request that she reduce her oral request to writing, Ms. Greenlaw did so, in the form of a written Motion to Compel. In that document, she sought "certain information which should have been revealed at the October 2-3, 2012 hearing." Specifically, Ms. Greenlaw sought "documentation of inter-communications between SCE&G and the Nuclear Regulatory Commission concerning the NRC's providing a July 2011 date as possible or probable for the awarding of the COL license." Ms. Greenlaw went on to request that such documentation "include dates and the names and contact information of the specific communicants." The fact that SCE&G and Westinghouse/Shaw anticipated the COL to be issued in mid-2011 was clearly disclosed in testimony and exhibits in Docket No 2008-196-E as was the fact that there were risks of delay in issuance. Questions concerning the reasonableness of those assumptions should have been raised at that time. In addition, in this Docket, ORS witness Jones testified that he had seen a document from NRC stating that date as the anticipated date for issuance of the COL. Tr. at 1132. Further discovery on this point is not warranted; nor is the timing of the request consistent with the goals of judicial economy. The Motion is denied.

The extensive testing and verification required by the NRC for approval of the new shield building design resulted in the COL being delayed by approximately nine months. (Tr. at 195.) Again, Westinghouse/Shaw asserted that the actions of the NRC in changing the aircraft impact requirements and in requiring an extensive testing regime for the new shield building design constituted an "uncontrollable circumstance" under the EPC Contract, and was thus compensable. Westinghouse/Shaw sought a change order for their additional costs in rescheduling the project. SCE&G challenged this claim. (Tr. at 194.)

(c) Structural Module Redesign

Westinghouse/Shaw is using modular construction techniques, similar to those used in the ship building industry, to increase efficiencies, reduce costs, and further standardization in construction of the Units. Under this approach, components of certain buildings, including walls, floors, electrical conduit, doorways and stairways are fabricated as sub-modules at a dedicated facility offsite and are assembled as modules on site at the Module Assembly Building. Once assembled, they are lifted and set in place in the Units. Structural modules for this project are being fabricated at the Shaw Modular Solutions ("SMS") facility located in Lake Charles, Louisiana.

Westinghouse's interactions with the NRC during the design approval of the AP1000 units resulted in a determination to use higher strength steel in the structural modules being fabricated by SMS and to make other design changes to improve constructability of the modules. Westinghouse/Shaw asserted that this change in the steel

specified for these modules was due to “changed conditions” in the form of a new regulatory mandate. SCE&G challenged this claim. (Tr. at 205.)

(d) Rock Conditions at Unit 2

Despite test borings in accordance with industry standards, excavation at the site of Unit 2 revealed areas where the upper level of bedrock was deeper than anticipated. This condition required additional excavation and filling with concrete to create a level base mat for the Unit. Mr. Byrne testified that it is not unusual upon excavation at a site to find that rock conditions are not uniform and require additional work resulting in an increase in costs. In this case, Westinghouse/Shaw had a valid claim to recover additional costs resulting from unanticipated rock conditions, which SCE&G did not contest. Mr. Byrne testified that SCE&G’s audit of the supporting documentation for this claim by New Nuclear Development (“NND”) teams resulted in its reduction by several hundred thousand dollars. He testified that the resulting settlement amount for unanticipated rock conditions was fully justified and reasonable. (Tr. at 207.)

(e) SCE&G Negotiation and Review of the Westinghouse/Shaw Claims

As to all the claims related to Change Order No. 16, members of the NND teams reviewed detailed documentation supporting the costs underlying them and assessed the level of those costs based on their construction and engineering experience. (Tr. at 195, 203, 206-07). In the end, as Mr. Byrne testified, no costs were approved that were not documented and substantiated. As a result of the initial cost documentation review and negotiations on the part of SCE&G, Westinghouse/Shaw revised their cost estimates downward, and reduced their overall claim from \$213.6 million to \$188 million. SCE&G

also challenged Westinghouse/Shaw's entitlements to claims, and, as a result of continued review and negotiation, ultimately convinced Westinghouse/Shaw to settle the full package of claims for \$137.5 million. In addition, SCE&G directed Westinghouse/Shaw to take advantage of the opportunity created by the delay in the construction schedule for Unit 2 to optimize construction schedules between the Units. Doing so created efficiencies which allowed Westinghouse/Shaw to reduce their claim for COL delay costs by approximately \$15.9 million. (Tr. at 190.) ORS also reviewed the request related to Change Order No. 16 in detail and concluded that the costs were reasonable and prudent. (Tr. at 1059, 1061, 1062.)

(f) Findings of Fact Related to Change Order No. 16

The Commission finds that SCE&G has demonstrated that the adjustments to cost schedules associated with Change Order No. 16 are not the result of imprudence by the Company but represent the necessary cost of the project. Further, Change Order No. 16 reflects the cost of a reasonable and well-negotiated resolution to a complex and difficult set of claims. The Commission finds, as Mr. Byrne testified, that the Company prudently reviewed the claims being presented, and appropriately challenged them and the assumptions underlying them as necessary. The Commission finds that the amount of the settlement is reasonable and that the benefits of such a settlement to the project, as Mr. Marsh and Mr. Byrne testified, are considerable, particularly compared to the prospect of the potential divisiveness, distraction and expense of litigating claims of such complexity.

**(g) The Challenge to Macro-Corridor Approach for Siting
Transmission Lines**

An Environmental Report ("ER") is the basis on which an Environmental Impact Statement ("EIS") is issued for a project such as this under the National Environmental Policy Act or NEPA. (Tr. at 198, 662-63.) For an electric generation project, the Environmental Report must assess the environmental effects of any new transmission lines that are necessary to support the project.

Under the approach used by SCE&G and other utilities, the determination of the precise routing of new transmission lines is a careful process, involving substantial outreach and data collection from landowners, local governments and local communities. The process also involves public record surveys and field surveys, and reviews of existing historical, cultural and environmental data from other sources. Typically, a final route is determined only after this work is done.

To accommodate this outreach, data collection and public input process, it is an accepted practice in the industry to file Environmental Reports for new generating plants showing the general route or "macro-corridors" in which transmission lines will be sited. The Environmental Report quantifies the environmental impacts expected from lines sited in those corridors based on general data about environmental conditions and ecosystems, flora and fauna, and other concerns within the corridors. The utility commits that in constructing and siting the lines it will conform to all environmental regulations and mitigation requirements, protecting these ecosystems, flora and fauna as required by

law. (Tr. at 200). The specific route of the lines within those corridors, however, is only determined after the public input process is completed.¹³

During the hearing in this docket, SCEUC challenged several of the SCE&G witnesses concerning the Company's use of the macro-corridor approach in filing its initial COL application and associated Environmental Report on the project. The record shows that SCE&G has successfully used the macro-corridor approach in permitting generation sites in the past. (Tr. at 201.) It did so in this case with the advice and support of highly experienced environmental consultants. In addition, Southern Company successfully employed the macro-corridor approach in siting and permitting its AP1000 units at Vogtle. (Tr. at 201.) In SCE&G's case, the macro-corridor approach garnered no objections during the scoping process and initial review of the filings. However, more than one year into the review process, the EPA, a commenting agency, asserted that the macro-corridor approach was unacceptable. This required SCE&G to fully site its transmission lines before the process could proceed. (Tr. at 201-02.)

SCEUC suggested that the rejection of the macro-corridor approach made SCE&G partially to blame for the NRC's delay in issuing the COL, and thus caused SCE&G to settle the Change Order No. 16 claims on less favorable terms. SCEUC put forth no witnesses or affirmative evidence on this point. SCE&G's witnesses affirmatively testified that the use of the macro-corridor approach was reasonable and prudent in all respects. There is no evidence that SCE&G changed its negotiating

¹³ By Order Nos. 2011-978 and 2012-730, the Commission has approved and issued SCE&G a Certificate of Environmental and Compatibility and Public Convenience and Necessity for the construction and operation of the transmission lines that will extend the Units and carry power to SCE&G's load centers.

approach or granted any concessions in its negotiations with Westinghouse/Shaw based on these issues.

The Commission finds that there is no credible evidence in the record of this proceeding sufficient to allow it to conclude that the use of the macro-corridor approach by SCE&G was imprudent or unreasonable. Rather, all the available evidence points to the contrary conclusion. Furthermore, the EIS was issued months before the COL. (Tr. at 202-03.) For that reason, the Commission finds on the record here, that there is no evidence sufficient to show that one delayed the other. Moreover, the Commission finds that the assertion that the delay in issuance of the EIS impacted SCE&G's bargaining position in this matter is purely speculative.

2. Owner's Cost

The Company is seeking BLRA approval of \$131.6 million in updates to Owner's Cost. Owner's Cost, as Ms. Walker testified, includes costs that SCE&G will incur in overseeing the construction project; recruiting, hiring, housing and training staff for the Units; preparing written operating procedures for operations maintenance; ensuring the safety and security of the Units; accepting, testing and maintaining the systems and components comprising the Units as they are completed and turned over to SCE&G; providing the materials and supplies needed for maintenance of plant systems up to the date of commercial operation; testing of the Units when they are released for that purpose; and in conducting start-up activities. (Tr. at 709.) Owner's Cost also includes a number of construction related cost items for which the EPC Contract makes SCE&G responsible. These items include workers' compensation insurance for all contractors

and subcontractors on the site; builder's risk insurance; transportation insurance related to the equipment and components of the project; miscellaneous taxes including real property and certain sales taxes associated with the project; electric power and other utilities for the project; site security; and certain preconstruction costs associated with the site. *Id.*

The current Owner's Cost forecasts reflect detailed cost-center-by-cost-center budgeting by the cost center comprising the New Nuclear Development ("NND") teams. These teams have direct responsibility for the project. In addition, detailed cost-center-by-cost-center budgets have been prepared for the support services that the project will receive from other, non-nuclear areas within SCE&G and SCANA. Such costs include support services from areas such as SCANA Audit Services, Legal, Treasury, Environmental, Forestry Services, Risk Management and Insurance, Facilities Management, and multiple groups within current Nuclear Operations (e.g., groups like Unit 1 Health Physics that may assist on an as-needed basis in creating staffing plans and writing operating procedures for parts of Unit 2 & 3 operations). Each cost center that anticipated direct support to the project was required to create a budget by cost type for each year through 2018 and update the budgets annually. These budgets were carefully reviewed by Ms. Walker and the Nuclear Finance group. (Tr. at 711-13.)

The Owner's Cost budget was sponsored by Ms. Walker. (See Tr. at 713, Chart B). It is a detailed budget document with over 400 individual line items. SCE&G has made the back-up information related to this budget available for review by ORS and all other parties, provided that reasonable arrangements related to confidentiality are made.

(Tr. at 715.) No party has filed any testimony challenging the prudence or reasonableness of any of the costs reflected in such Owner's Cost budget.

In Hearing Exhibit No. 6 (CLW-2), Ms. Walker provided an item-by-item analysis of the cost adjustments being presented for review in this docket. In an effort to provide more detailed information about the changes driving the \$131.6 million in newly-itemized Owner's Cost, Ms. Walker provided testimony breaking down the \$131.6 million into its principal categories and showing the changes from the previously approved budgets.

(a) Updated Staffing

The largest component of SCE&G's proposed adjustment to Owner's Cost is represented by changes to staffing. As Mr. Lavigne testified, the initial Owner's Cost projections were prepared during the period 2005-2008 based on the best information obtained from utility and nuclear trade groups, other prospective AP1000 owners, nuclear technology companies, internal SCE&G personnel with experience in nuclear operation and in overseeing major construction projects and other sources. After the EPC Contract was signed, SCE&G intensively reviewed the initial staffing, hiring and training plans for the Units based on emerging data related to the integrated site schedule, the AP1000 design, its operating and maintenance requirements, and emerging security and regulatory requirements. Such reviews also took into account SCE&G's experience in supporting the construction project and in meeting the requirements of its role and function in overseeing the cost, quality, and timeliness of the project. (Tr. at 557.) The staffing plan resulting from that review was approved in Docket No. 2010-376-E.

Since that time, Mr. Lavigne testified, SCE&G has continued to review Owner's Cost forecasts as additional information emerged concerning plant design, the events at Fukushima, security requirements at the plant, difficulties obtaining and licensing personnel, and delays in the issuance of certain permits and licenses. In the latter part of 2011, the Company established "challenge boards" comprised of experienced personnel from Unit 1 and other areas of SCE&G. The members of these boards had diverse backgrounds in nuclear operations, safety, security, plant operations and maintenance, engineering, quality systems, training, construction, planning and scheduling, outage, organizational development and planning, licensing, chemistry, documents and records, materials and procurement, health physics, and emergency planning. The challenge boards concluded that the staffing plan at that time did not provide for the hiring and training of sufficient personnel to manage startup and operate the Units reliably and effectively. (Tr. at 559.)

The reviews and refinements to staffing resulted in the addition of 95 full time equivalents ("FTEs") in Operational Readiness, 29 FTEs in Construction Oversight, Quality Assurance/Quality Control ("QA/QC") and other project support functions, and 20 FTEs in nuclear security contracting, representing a net adjustment of \$72.3 million. On a functional basis, these affected areas include: (1) Emergency Planning/Health Physics (Fukushima), (2) Operator/Training Margin, (3) APOG¹⁴/Programs/Procedures, (4) Timing Variance to Support Craft, (5) Nuclear Construction Oversight and QA/QC, (6) Security Contractors, and (7) Other. (Tr. at 562.)

¹⁴ The AP1000 Owner Group, discussed more fully below.

These updates in FTEs and in costs are set forth in the table below which is taken from Mr. Lavigne's testimony. The costs presented here reflect both the cost of additional FTEs and the cost of accelerating the hiring date of existing FTEs where doing so has been found to be important to support the training and testing schedule for the Units or otherwise meet the needs of the project.

Table D

Staffing Changes by Functional Cause

<u>Cause</u>	<u>FTE Change</u>	<u>Cost Change (millions)¹⁵</u>
Emergency Planning/Health Physics (Fukushima)	40	\$5.9
Operator/Training Margin	30	\$17.4
APOG / Programs / Procedures	22	\$15.7
Timing Variance to Support Craft and Technical Training Program	3	\$15.5
Nuclear Construction Oversight and QA/QC	26	\$8.6
Other		<u>\$3.1</u>
Total SCE&G	124	\$66.2
 Security Contractors	 <u>20</u>	 <u>\$6.1</u>
TOTAL	144	\$72.3

¹⁵ The labor costs that form part of Owner's Cost are not annual salary costs. Instead, they represent the labor costs and associated costs incurred over the ten-year life of the project for members of the NND teams. For that reason, if the decision is made to accelerate the hiring of a position by three years, all other things being equal, then there would be no increase in FTEs for the project. However, the Owner's Cost budget would increase by three times the annual salaries, benefits, facilities, IT charges and other costs associated with having that individual on staff. For that reason, the change costs for a category listed above does not necessarily correlate to the change in FTEs for that category.

(i) **Operator/Training Margin**

As Mr. Lavigne testified, the largest single driver of the staffing cost adjustment is in the area of Operator/Training Margin. SCE&G cannot complete testing and begin start up of the Units unless, when it has completed construction of the Units, the NRC is satisfied that SCE&G has sufficient reactor operators trained, licensed, and ready to allow fuel to be loaded. The staff of licensed operators must be sufficient to staff the Units twenty-four hours a day, seven days a week, with allowances for training time and personal leave and other absences for operators. Industry experience has shown that it takes 3-7 years to train and license a nuclear reactor operator.

Mr. Lavigne testified that hiring and training reactor operators have become more difficult in recent years. Given the nature of today's military, fewer candidates are available for reactor operator training who have significant nuclear experience. Due to the aging workforce of reactor operators nationally, the industry is hiring in anticipation of impending retirements. As a result, competition to attract and retain good reactor operator candidates is more intense than in the past. Furthermore, the training and testing requirements for licensure by the NRC have increased dramatically in recent years. (Tr. at 566.) As Mr. Lavigne testified, another utility recently experienced a surprisingly high failure rate when a cadre of newly-trained candidates sat for their licensure examinations. Mr. Lavigne succinctly summarized the challenge, stating "we must train less experienced candidates with less practical exposure to the work to meet higher licensing standards while facing greater competition to retain them." Tr. at 565.

In response to this challenge, SCE&G is proposing to hire more operator candidates and to hire them sooner. Hiring candidates earlier allows more time to train them. Hiring a larger group of candidates creates a buffer to protect against higher than expected attrition and exam failure rates among candidates. The change in Operator/Training Margin represents 30 FTEs and \$17.4 million of the staffing related update. (Tr. at 564-66.)

(ii) Emergency Planning/Health Physics

Another significant driver of the updated personnel costs presented here is in the Emergency Planning/Health Physics area. Mr. Lavigne testified that the industry and NRC are placing greater restrictions on the responsibilities that can be assigned to emergency personnel as a lesson-learned from the Fukushima event. Past practice allowed for emergency personnel such as fire brigade members and health physics workers to assume additional duties that were not anticipated to interfere with emergency response capabilities. In addition, emergency response personnel at one unit were assumed to be available to supplement the staff responding to a disaster at a sister unit. (Tr. at 563.) As a result of Fukushima, the NRC has published guidance limiting the number of collateral duties that may be assigned to emergency response personnel. The industry and NRC now require staffing at levels that provide a full complement of staff to be available to respond to each unit assuming simultaneous disasters at all units on a site. Mr. Lavigne testified that these new limits on shared duties for emergency personnel results in the need for an additional 40 FTEs at a cost of \$5.9 million. (Tr. at 563-64.)

(iii) APOG/Plant Programs/Procedures

An important part of preparing a new nuclear unit for operation is drafting and promulgating the plant programs and procedures that are necessary to operate and maintain the Units, respond to events and emergencies and provide for security and related functions. SCE&G has determined that operating and maintaining these Units will require drafting approximately 100 plant programs (*e.g.*, the Thermal Performance Program, the Equipment Reliability Program, and the System Status Control Program) and 4,200 procedures. Prior cost forecasts were based on the assumption that the burden and cost of drafting these programs, most of which can be uniform across AP1000 units, would be borne by five AP1000 owners comprising the AP1000 Owner Group ("APOG"). However, at present only two of the five members of the group, SCE&G and the Southern Company, have active EPC contracts with Westinghouse/Shaw. As a result, only these two members have the right under their agreements to have access to Westinghouse/Shaw's proprietary design and engineering data related to the Units. Such access is necessary to participate in the shared drafting exercise. As a result, SCE&G and Southern Company must share the drafting responsibilities among themselves rather than among a group of five utilities. This has resulted in the need for 22 additional FTEs and represents \$15.7 million of the requested cost. (Tr. at 566-68.)

(iv) Timing Variance to Support Craft

The safe and efficient operation of the Units will require a staff of well-trained craft workers in areas such as chemistry, maintenance, outage and planning, and scheduling. In reviewing its staffing plans through the challenge board process, SCE&G

determined that three additional FTEs would be required in this area to ensure that a sufficient number of trainees will successfully complete the INPO¹⁶ accredited training programs in their areas of specialization. SCE&G also concluded that it is important that certain Unit 2 and 3 craft workers be trained earlier than expected so that they can be given the opportunity before commercial operations of those Units begin to develop hands-on experience with nuclear operations and with the systems comprising Units 2 and 3. For that reason, Mr. Lavigne testified that SCE&G had decided to hire and train craft workers earlier than anticipated to allow them to work with Westinghouse/Shaw personnel during the startup of the Units and to work alongside their colleagues at Unit 1 doing similar tasks there. The Timing Variance to Support Craft results in three additional FTEs and an increase to Owner's Cost of approximately \$15.5 million. (Tr. at 568-69.)

(v) Nuclear Construction Oversight and QA/QC

Based on experience gained so far in constructing the Units, the Company has determined that additional personnel are needed to effectively oversee the cost, quality and safety of the project. As Mr. Lavigne testified:

[T]here is no substitute for the accountability provided by an owner's direct involvement and insistence on quality and timely work. The NRC concurs in this, and has made it very clear that they hold SCE&G ultimately accountable as owner/licensee for the quality, reliability and safety of the Units as constructed. They expect SCE&G to be actively and directly involved in overseeing all aspects of the work and we agree. The value of additional personnel to oversee the construction effort and the world-wide procurement chain for this project cannot be overstated.

¹⁶ Institute of Nuclear Power Operations.

(Tr. at 569-70.) To support the desired level of QA/QC oversight, SCE&G has added 26 FTEs totaling \$8.6 million of the update. (Tr. at 570).

(vi) Security Contractors

The size of the work force required to provide security to the site is determined by threat response planning. Such planning is based on current NRC and industry guidance as to anticipated levels of threat and the required levels of security response. Threat response planning is very site-specific and depends on the precise layout of support buildings, access points, and site topography. For that reason, an updated count of security personnel needed for the Units could not be completed until the layout and configuration of the facilities on site was finalized. Since 2010, Westinghouse/Shaw's design work has progressed to the point that the site layout is well established. Based on this information, and current NRC guidance related to security planning, SCE&G has updated its security staffing plans for the Units. These refinements have resulted in SCE&G adding 20 additional FTEs for security contractors at a cost of \$6.1 million. (Tr. at 570-71.)

(vii) Other

Under the Other category are costs associated with the personnel necessary to ensure that all Westinghouse/Shaw records are obtained and captured for current and future use and are secured as required by the NRC regulations. These are QA/QC, engineering, construction and security related documents that are of importance to future operations and regulatory compliance. The number of required personnel for these tasks has increased while demand for staff in areas of business and finance have decreased.

(Tr. at 570.) The net result is an increase in forecasted staffing of three FTEs and costs of \$3.1 million.

(viii) SMS Oversight Costs

For a number of years, SCE&G has expressed concerns in update dockets and quarterly reports concerning the difficulties SMS was experiencing in establishing an effective nuclear safety culture at its facilities in Lake Charles, Louisiana. Over time, SCE&G has steadily increased its level of QA/QC oversight for SMS. Recently, SCE&G has taken the steps of placing a full time presence dedicated to owner's quality inspection at the SMS site, in addition to the dedicated QA/QC personnel located there by Westinghouse/Shaw.

At the hearing, certain parties raised concerns about SCE&G's inclusion in its forecasts of costs associated with additional costs SCE&G incurred in providing QA/QC oversight for SMS.

The Commission understands the impulse to require SMS to absorb these costs. However, it is customary in the industry, and beneficial for many reasons, for an owner's QA/QC efforts to be at its sole expense and under its exclusive authority. The EPC Contract does not provide for recovery of QA/QC expense from any other party, nor would the Commission expect it to. Under the BLRA, specifically S.C. Code Ann. § 58-33-270(E), there is no basis to rule that it was imprudent on SCE&G's part to invest additional resources in overseeing QA/QC issues at the SMS facility. To the contrary, such an investment is prudent to a very high degree. For that reason, the Commission finds that the SMS oversight costs, and oversight costs related to other suppliers and

contractors, are reasonable, prudent and necessary costs of the project and should be included in the approved capital cost schedule.

(ix) Findings Related to Staffing Costs

The Commission has reviewed the testimony and evidence presented in this docket that is related to the update in staffing costs. No evidence has been presented that is sufficient to allow the Commission to conclude that these changes were the result of imprudence by SCE&G. For the reasons stated above, and in the testimony of Mr. Byrne, Mr. Lavigne, and Ms. Walker, the Commission finds that these increases in the forecasted cost of staffing are not the result of imprudence on the part of SCE&G but instead represent reasonable, necessary and prudent costs of the project.

(x) APOG Programs/Procedures and Related Cost Increases

At the hearing, certain parties seemed to question the appropriateness of the cost forecasts for the project being increased as a result of the change in the drafting of plant programs and procedures related to APOG. The evidence clearly establishes that drafting of these programs and procedures is a reasonable, necessary and prudent part of the project. Through APOG, SCE&G is sharing the cost of this effort with the Southern Company, which will reduce the cost borne by SCE&G's customers significantly. SCE&G is acting prudently in using APOG to share these costs with additional utilities. While it would be beneficial if more utilities could share in the efforts requiring proprietary data, SCE&G cannot dictate to Westinghouse how it enforces its intellectual property rights as they affect this effort. No party offered any affirmative evidence showing that SCE&G has acted imprudently in its dealings with APOG or with the cost

of drafting the required programs and procedures. Instead, the evidence shows that SCE&G has acted prudently to reduce costs to customers by having as many utilities as possible share the cost and burden of this effort. The Commission finds that the increase in cost related to APOG Programs/Procedures is a reasonable, prudent and necessary cost of the project and should be included in the approved capital cost schedule.

(b) Facilities

The facilities component of Owner's Cost includes the construction, up-fitting and furnishing costs of the buildings, and training facilities needed to support the operations of the Units once they are constructed, and the cost incurred in providing training, office and other space for the NND teams and other members of the project team during the construction period. All of these costs are not annual costs but costs to be incurred over the ten-year course of the project. (Tr. at 718-21.)

SCE&G's witness, Ms. Walker, presented the updates to facilities costs that form part of the Owner's Cost update and provided a detailed breakdown of the categories and drivers of these costs. She testified that additional maintenance costs amounting to \$1.9 million comprised the largest single item in this cost category. These costs are the direct result of the accelerated hiring of staff detailed in Mr. Lavigne's testimony. (Tr. at 719.) The accelerated hiring schedule also drives the need to add modular buildings and temporary office space in the facilities plan during the construction period. The cost of these additional facilities represents approximately \$1.0 million. Other changes in the cost of facilities result from the increased number of dedicated emergency personnel required in response to the events at Fukushima and the facilities required to house those

personnel and equipment. Similarly, additional site planning and security planning have identified additional costs related to site-specific security facilities and other facilities related to site access. In total, the update to facilities costs represents \$7.8 million of the increase in Owner's Cost. (Tr. at 721-722.)

No party in this proceeding presented any direct evidence challenging the reasonableness or prudence of these updates to facilities costs. In its testimony, ORS's witness, Mr. Jones, found these costs are justified and reasonable. (Tr. at 1071.) Based on the testimony of Ms. Walker and Mr. Jones, the Commission finds these costs to be necessary, reasonable and prudent costs of the project. The Commission finds that no party has made any showing that these costs are in any way the result of imprudence on the part of SCE&G. It is appropriate to reflect these costs in the approved cost forecasts for the project.

(c) Information Technology ("IT") Roadmap

Effective IT infrastructure is critical to safe and efficient nuclear operations. A major part of such infrastructure is the software that is used in tracking the maintenance history of parts and equipment, documenting scheduled and preventative maintenance, tracking spare parts and inventory on hand, recording where specific parts have been used in the plant, scheduling maintenance requests, preparing work schedules, administering employee fatigue management and safety rules, and ensuring that safety and quality assurance documentation is maintained and available for use and inspection. (Tr. at 715-717.)

Ms. Walker testified to SCE&G's update to the cost forecasts for delivering IT services to the project. According to Ms. Walker, the IT budget presented in Docket No. 2010-376 was a roll-up of individual budgets for IT services formulated by the managers in each NND area for their areas. In most cases, these budgets relied on the assumption that existing Unit 1 programs and infrastructure could be scaled up to meet the IT needs of Units 2 and 3. (Tr. at 716.)

In 2011, SCANA's IT department ("SCANA IT") was tasked with creating a formal and detailed "IT Roadmap" for the project based on a thorough inventory of the available software, infrastructure and licenses, and the needs of the project and the Units. Based on its review, SCANA IT concluded that much of the IT infrastructure in use at Unit 1 was not scalable to support the new Units.

No party in this proceeding has challenged the prudence of the costs associated with implementing the new IT Roadmap. While Dr. Cooper testified that he was concerned that Unit 1 IT upgrade costs might be included in the Unit 2 and 3 cost estimates (Tr. at 971.), Mr. Byrne refuted that testimony. (Tr. at 277-78.) The Commission finds Mr. Byrne's testimony to be credible and finds no basis to conclude that Unit 1 IT costs are improperly included here.

For the reasons stated in Ms. Walker's testimony, the Commission finds that these additional IT costs are not the result of imprudence by the Company but that they are reasonable, necessary and prudent costs of the project. The Commission finds that it is appropriate to reflect them in the approved cost forecasts for the project.

(d) Conclusions as to Owner's Cost Updates

The testimony of Mr. Byrne, Mr. Lavigne, Ms. Walker, and Mr. Jones provides sufficient evidence supporting the reasonableness and prudence related to each of the components making up the \$131.6 million adjustment. The record shows that Ms. Walker testified as to the reasonableness and prudence of each of these items and to the reasonableness and prudence of the overall \$131.6 million adjustment to the Owner's Cost category. (Tr. at 708-09.) Her testimony is supported by similar testimony from Messrs. Marsh, Byrne and Lavigne. (Tr. at 43, 165, 572.) ORS also conducted its own review and provided testimony finding that the \$131.6 million of Owner's Cost represents a "reasonable cost increase for the Project." (Tr. at 1072.) The key drivers as to each element of cost have been presented clearly and distinctly in the evidence contained in this record.

As to the reasonableness of the budgets and budget process on which these Owner's Cost adjustments were based, Ms. Walker testified:

The budgets for each [item of Owner's Cost] have been carefully reviewed and evaluated for reasonableness. This analysis confirms the reasonableness of the adjustment in Owner's Costs for the categories listed above, and supports the conclusion that the updated Owner's Costs budget is a reasonable and prudent estimate of the cost associated with this construction project.

(Tr. at 770.) In addition to this testimony, ORS witness Jones testified that ORS has reviewed these costs and has determined them to be reasonable. (Tr. at 1043.)

For all the reasons set forth above, and having reviewed the testimony and the exhibits in the record of this proceeding, the Commission finds that no party has

presented evidence showing that the \$131.6 million adjustment to Owner's Cost is in any way the result of imprudence by SCE&G. Instead, the Commission finds that the update reflects a reasonable, necessary and prudent adjustment to the cost schedules for the project, and that there is no evidence in the record to suggest that they are the result of any imprudence on the part of the Company.

3. Transmission Cost

Since the issuance of Order No. 2011-345, the Company has continued to update its transmission cost forecast to reflect current information concerning the design and siting of the lines and other facilities, and the costs of right-of-way siting proceedings. SCE&G has updated its transmission cost forecast by \$7.9 million. This net increase in the transmission cost forecast is comprised of increases of (1) \$1.6 million to construct a new Saluda River Transmission ("SRT") substation, (2) \$3.6 million for other transmission line construction, (3) \$2.7 million to upgrade various substation equipment, and (4) \$1.4 million for right-of-way and property acquisition. This amount also reflects a decrease resulting from a reallocation of costs between SCE&G and Santee Cooper of \$1.4 million.

(a) The SRT Substation

SCE&G originally planned to accommodate the delivery of power from the Units into the load centers in the Lexington and Lake Murray areas by adding additional autotransformers at its existing Lake Murray 230/115 kV Substation and its Denny Terrace 230/115 kV Substation. (Tr. at 648.) However, as Mr. Young testified, recent engineering work showed that the two existing substations did not have sufficient space

to allow new autotransformers to be located in them without costly expansions. Those expansions would be equivalent to building new substations beside each of the two existing substations. Subsequent power flow studies showed that this plan would require a third transformer to be installed at the Lyles 230/115 kV Substation. (Tr. at 632, 646-650.) In addition, the decision to route the new lines to serve the Units on existing right-of-way created the opportunity to build the SRT substation in an area with high demand where a new substation would be beneficial.

The cost of the new SRT substation is \$1.6 million more than the original cost of the autotransformers design, and is much less than the cost of that design (\$27.8 million) when the costs of expanding the existing substations and adding a third transformer is considered. Other improvements benefiting the transmission system as a whole are also being made under this plan. The cost to the nuclear project is being reduced by appropriately allocating costs to system improvements where the existing transmission system, not the project to construct the Units, is the principal beneficiary of the specific costs. (Tr. at 652.)

(b) The Parr-VCSN Safeguard Line Underground

The Parr-VCSN Safeguard 115 kV Line currently provides back-up power to the safety-related components of Unit 1. (Tr. at 653.) Mr. Young testified that under the current design for the new transmission lines for the Units, the Parr-VCSN Safeguard 115 kV Line would cross five 230 kV lines at one location. In a worst-case scenario, the Parr-VCSN Safeguard Line could fall on these lines and cause all six lines to go out of service resulting in a loss of service to a large number of customers. To alleviate reliability and

safety concerns related to this configuration, a short segment of the Parr-VCSN Safeguard Line will be rebuilt underground at a cost of \$2.9 million. (Tr. at 655.)

(c) Lowering the Parr-Midway Line

The current design for the lines serving the site results in seven 230 kV lines crossing the Parr-Midway 115 kV lines. Further design and engineering reviews have shown that in the area of crossing that SCE&G must lower the Parr-Midway 115kV lines to meet NERC safety guidelines. Mr. Young testified that lowering these lines is the most cost effective solutions to address these safety concerns. The cost for lowering these lines is \$704,000. (Tr. at 656.)

(d) Various Substation Improvements

Mr. Young testified that continued design work and power flow analysis had shown that improvements to several substations across the system were required to safely and efficiently route the power from the Units to customers. Because the existing disconnect switch at V.C. Summer Switchyard No. 1 does not have the power current rating necessary to function properly when Units 2 and 3 become operational, SCE&G must replace a bus side disconnect switch as well as existing lightning arresters. The cost for these changes is \$614,000. Similarly, recent transmission design and engineering work has shown that SCE&G must also make improvements at three existing substations in order to increase their power ratings and interconnect new transmission lines with SCE&G's existing system. These improvements include an upgrade to the bus and terminal at the Canadys 230 kV Substation, an upgrade to the terminal at the Summerville 230 kV Substation, and the upgrade of two terminals at the Saluda Hydro

Substation. The estimated cost for these three substation improvements is \$2.1 million.
(Tr. at 657-59.)

(e) Costs of the Blythewood-Killian Segment

The Company is constructing the Blythewood-Killian Segment of the VCS1-Killian 230kV Line along new right-of-way. Building this segment requires SCE&G to obtain, through purchase or condemnation, right-of-way for that line. Based on the results of siting studies like those discussed above, the line as finally sited crosses an area of higher property values than was originally anticipated. Based on actual right-of-way costs incurred to date, the right-of-way cost forecast has increased by \$369,000. Several condemnations are ongoing and changes to these costs are possible but have not been finalized. (Tr. at 660.)

In Docket No. 2011-325-E, SCE&G entered into settlement agreements with Richland County and with the Town of Blythewood concerning legal challenges that they brought to the siting of the Blythewood-Killian segment in areas of concern to them. Both political subdivisions intervened in the Commission siting proceeding for the line and actively opposed the siting of the line as SCE&G proposed. SCE&G estimates that had Richland County and the Town of Blythewood prevailed in their request to reroute the line, the additional costs to the project would have been \$6.3 million and \$26.0 million, respectively. (Tr. at 662.) Complying with the request of the Town of Blythewood could have also delayed the issuance of the COL because the resulting route of the transmission lines would have been inconsistent with the route set forth in the ER on which the EIS for the COL was based.

SCE&G settled its dispute with Richland County for \$1.0 million and with the Town of Blythewood for \$450,000. The Richland County settlement included payment for a contested right-of-way easement across a large tract of county-owned land. Both settlements resolved all outstanding issues between the political subdivisions and the Company relating to the siting of the line. (Tr. at 661-63.) Pursuant to the Commission's decision in Order No. 2009-104(A) concerning allocation of the costs of these lines between the project and general transmission system improvements, SCE&G is currently requesting 74.2% of the settlement amounts be included in the cost schedules for the Units.

(f) Reductions to Allocations to Santee Cooper

The costs listed above are offset in part by a reduction in cost allowed to SCE&G for facilities that benefits both SCE&G and Santee Cooper. Historically, SCE&G and Santee Cooper have allocated the cost of shared-use transmission assets at the VC Summer site on an item-by-item basis. Specific allocations were made for individual switches, structures, and other pieces of equipment. Recently, SCE&G and Santee Cooper have agreed instead to allocate costs based on the proportion that each makes use of specific facilities like switchyards and lines rather than individual components of them. The resulting reallocation of costs between Santee Cooper and SCE&G results in an approximate \$1.4 million decrease to the transmission cost forecast. (Tr. at 664-65.)

The Commission has carefully reviewed the evidence and testimony related to transmission cost presented by the Company discussed above as well as the testimony and conclusions of the ORS (Tr. at 1123). The Commission finds that there is no

evidence establishing imprudence on the part of SCE&G. No party presented evidence contesting these costs. The Commission finds these costs to be reasonable, prudent and necessary costs of the project. They are properly included in the updated costs forecasts.

4. Other Change Orders

The cost schedules presented here for approval contain costs associated with three change orders that predate the Change Order No. 16 settlement and relate to different scopes of work. Those three additional change orders are Change Order Nos. 12, 14 and 15.¹⁷ They reflect additional costs for compliance with new federal healthcare mandates, cyber-security measures, and the minor redesign of a wastewater piping system.

Collectively, Change Order Nos. 12, 14 and 15 represent \$6.0 million of the cost update at issue here. Of these change orders, Change Order No. 14 related to cyber-security represents more than 95% of the total \$6.0 million amount. Company witnesses Mr. Byrne and Ms. Walker provided testimony as to the reasonableness and prudence of the costs reflected in these change orders. (Tr. at 208-212, 723-24.)

(a) Change Order No. 12

Change Order No. 12 is based upon a request by Westinghouse/Shaw for reimbursement of Shaw's increased costs as a result of a change in law related to portions of the Health Care and Education Reconciliation Act of 2010 (the "Health Care Act") and prior health care acts. (Tr. at 210.) The total costs associated with this change are \$135,573 and such costs are spread throughout the remaining period of the project. Mr. Byrne testified that SCE&G has verified the amounts involved and that they are accurate.

¹⁷ Change Order No. 13 was a no-cost change order related to IT workstations for plant operators.

He testified that the additional health care costs are the result of new legal requirements imposed on Westinghouse/Shaw and that they are reasonable, necessary and prudent costs of the project. (Tr. at 211.) Westinghouse/Shaw may identify other change orders related to health care costs but no additional change orders have been identified to date. (Tr. at 210.)

(b) Change Order No. 14

As Mr. Byrne testified, it has become critical as a matter of national security to protect key electric infrastructure against cyber attack. The NRC now requires robust cyber-security measures to be incorporated in all new and existing nuclear facilities. SCE&G has reached an agreement with Westinghouse/Shaw to use a phased approach for ascertaining the costs associated with strengthening the Units' defenses against cyber-attack. (Tr. at 209-10.) Change Order No. 14 reflects costs related to strengthening the Units' defenses against cyber attack.

Under the agreement between SCE&G and Westinghouse/Shaw, Phase I of the cyber-security plan will involve a review of the specific equipment and software that will be used in the Units to identify potential vulnerabilities to cyber-attack. Westinghouse/Shaw will also devise a scope of work to protect against those vulnerabilities. Phase II will involve the actual software programming and other work necessary to overcome the vulnerabilities identified in Phase I. The contractual costs of Phase I and the forecasted costs of Phase II are reflected in Change Order No. 14. The combined costs of both phases are currently estimated to be \$5.9 million. The final costs of Phase II will depend on the results of work done in Phase I. (Tr. 209-10.)

In his prefiled testimony, ORS witness Mr. Jones expressed concerns that the cost increase estimate for Phase II of the cyber-security regime might be premature. He suggested that the Commission should wait until Phase I is completed before approving any forecasted costs for Phase II. For that reason, he recommended that the Commission include only the \$914,422 cost of Phase I in approved forecasts and delay the requested \$4.9 million cost of Phase II until a later update filing when there is a better definition of the cost, time and scope attributable to such work. (Tr. at 1062-63.)

We agree with the Office of Regulatory Staff on this matter. We find that the Phase II costs in the cyber-security area will depend directly on what is done in Phase I, and that a better definition of the cost, time, and scope attributable to the work in Phase II is needed before this Commission can approve monies for Phase II of the cyber-security project. In addition, there is some discussion about the fact that Phase II costs may be shared with other AP1000 plants. It is reasonable to delay approval of these costs until the possibility of sharing is further elucidated. Phase I of the cyber-security change order is supported by the evidence of record and is properly included in the updated capital cost.

(c) Change Order No. 15

Change Order No. 15 pertains to additional costs associated with a revision of the design of the waste water discharge piping for the Units to provide for gravity drainage, and with healthcare costs related to a change in law related to portions of the Health Care and Education Reconciliation Act of 2010. Mr. Byrne testified that SCE&G prefers the gravity design because it involves fewer pumps, motors and other moving parts that

require maintenance. SCE&G understood when it submitted its COL application that there could be a charge associated with this change but that the cost would only be known when the design was complete. Now that design work is complete, Westinghouse/Shaw has determined that the cost of this work will be \$8,250. Mr. Byrne testified that SCE&G has verified this amount and finds it to be a reasonable and prudent cost that supports a beneficial change to the project design. (Tr. at 211-12.) Further, the additional proposed healthcare costs of \$135,573 covers costs related to a change in law related to portions of the Health Care and Education Reconciliation Act of 2010. This figure is also supported by the evidence.

(d) Conclusion as to the Three Change Orders

The Commission finds that no party has shown that the cost associated with these three change orders is the result of imprudence on the part of SCE&G, although we hold that the monies associated with Phase II of the cyber-security project are so indefinite and undefined at this point that we cannot approve said monies. Also, the Phase II cyber-security costs may be subject to sharing with other AP1000 plants, which is a further reason to withhold approval of such monies.

The Commission holds that, with the exception of the Phase II costs for the cyber-security project, costs associated with these three change orders are reasonable and prudent costs of the project and there is no evidence in the record to suggest otherwise. Once the monies associated with Phase II of the cyber-security project become definite and defined, and the possible sharing of these costs with other U.S. AP1000 plants has

been explored and elucidated, the Company may submit such costs to this Commission for further consideration.

C. Unanticipated Costs

At the hearing in this matter, the SCEUC seemed to take the position that the Commission might disallow certain costs because SCE&G should have anticipated them when cost schedules were presented for approval in past proceedings. (See, *e.g.*, Tr. at 331, l. 22-24; 339, l. 20-25; 586, l. 11-14.) The Commission does not adopt this approach for several reasons. The Commission finds that the cost forecasts adopted in prior orders were based on extensive evidence indicating that they represented the best information available to the Company at the time they were adopted. The forecasts were fully litigated in contested case proceedings before the Commission. The ORS carefully reviewed and audited these forecasts. Public notice was given and interested parties were given the opportunity to intervene in the proceedings as parties with full rights of discovery and cross-examination. At the hearing, the Company presented extensive testimony subject to cross-examination supporting these forecasts. On the basis of that record, the Commission entered express findings that those forecasts were reasonable and prudent. See Order No 2009-104(A); Order No. 2011-345.

The Commission does not believe that it is appropriate as a matter of regulatory practice and policy, nor is it consistent with the terms and intent of the BLRA, to rule that the failure to anticipate certain costs is imprudent, where it has already ruled, after a full contested case hearing, and a full and candid presentation of cost forecast data to the Commission, that the cost forecasts being alleged to be imprudent reasonably and

accurately reflected the anticipated cost of the Units at the time. To rule otherwise is neither fair nor logical and results in the sort of after-the-fact relitigation of prudence questions that the BLRA was intended to discourage.

D. Construction Milestone Schedule Changes

Company witness Mr. Byrne sponsored Exhibit No. 1 (SAB-3), which updates the construction milestone schedule for the Units to reflect the substantial completion date for Unit 2 of March 15, 2017, and for Unit 3 of May 15, 2018. (Tr. at 212.) Mr. Byrne testified that these updated schedules are based on construction milestones and equipment fabrication and procurement milestones provided by Westinghouse/Shaw in response to the decision to reschedule the Units. Based on Mr. Byrne's testimony, the Commission finds that the updates to the construction milestone schedule are prudent and reasonable in all respects. (Tr. at 212-13.) The updated construction schedule (attached herein as Order Exhibit 2) shall be substituted for Exhibit 1 to Order No. 2009-104(A).

IV: CONCLUSION

For the reasons set forth below, the Commission finds that the changes to the cost, with the exception of the cost of Phase II of the cyber-security project, and construction schedules proposed by SCE&G are reasonable and prudent and comport with the terms of the BLRA. Having carefully reviewed the record in this proceeding, the arguments of the parties, and the operative provisions of the BLRA, the Commission does not find any basis for concluding that the \$278.05 million in newly identified and itemized costs are in any way the result of SCE&G's failure to manage the project prudently. Instead, the evidence of record shows that the \$278.05 million in newly identified and itemized

capital costs are the result of the normal evolution and refinement of construction plans and budgets for the Units. The costs that SCE&G is incurring will ensure that the project is constructed prudently and that the Units can be operated and maintained safely and efficiently when they are completed.

As to the prudence of continuing construction of the Units, the Commission finds that SCE&G has presented evidence establishing that the most prudent, reasonable and beneficial base load resource strategy for it to pursue at this time is to complete construction of the Units as proposed. The evidence shows that it would not be prudent, reasonable or beneficial to SCE&G or its customers to switch to a natural gas resource strategy. While this finding is justified by the evidence presented at hearing, this Commission also finds that the BLRA does not require that this issue be relitigated once the initial finding has been made.

Similarly, the Commission finds that the changes in the construction schedule presented here reflect a reasonable and prudent response to the effects of the unanticipated delay in issuing the COL for the Units and other matters. This delay was not the result of any imprudence by SCE&G. The delaying of the construction schedule for one Unit and accelerating the schedule for the other does not in any material way change the benefit of the Units to SCE&G and its customers.

In accordance with the terms of S.C. Code Ann. §§ 58-33-270(E) and 58-33-270(G), the Commission finds that the revised cost (except for the Phase II costs of the cyber-security project) and construction schedules presented reflect prudent costs and schedules and should be approved.

V. PROCEDURAL FINDINGS AND LEGAL STANDARDS

1. In Order No. 2009-104(A), dated March 2, 2009, the Commission approved a capital cost schedule for the construction of two 1,117 net MW nuclear power units to be located at the SCE&G's V.C. Summer Nuclear Station near Jenkinsville, South Carolina. The approved capital cost for the project totaled \$4.5 billion in 2007 dollars.

2. In Order No. 2010-12, the Commission approved an updated construction schedule for the project and an updated capital cost schedule that reflected the updated construction schedule. The capital cost schedule approved in Order No. 2010-12 did not alter the total estimated capital cost for the Units of \$4.5 billion in 2007 dollars.

3. On August 9, 2010, the South Carolina Supreme Court issued its decision in *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, 388 S.C. 486, 697 S.E.2d 587 (2010), concerning SCEUC's appeal of Order No. 2009-104(A). In its Opinion, the Court ruled that contingency costs which had not been itemized or designated to specific cost categories were not permitted as a part of approved capital cost schedules under the BLRA.

4. In Order No. 2011-345, the Commission approved an updated capital cost schedule in response to the Opinion, which removed from approved schedules costs that had not been itemized to specific capital cost items and approved \$174 million in adjustments to reflect newly itemized costs. The capital cost schedule approved in Order No. 2011-345 reduced the total approved capital cost forecast for the Units to \$4.3 billion in 2007 dollars.

5. Under S.C. Code Ann. § 58-33-270(E), a utility may petition the Commission “for an order modifying any of the schedules, estimates, findings, class allocation factors, rate designs, or conditions that form part of any base load review order.” The Commission shall grant the relief requested if, after a hearing, the Commission finds “that the evidence of record justifies a finding that the changes are not the result of imprudence on the part of the utility.”

6. On May 15, 2012, SCE&G filed the Petition in this docket, pursuant to S.C. Code Ann. § 58-33-270(E) (Supp. 2010), seeking an order approving an updated capital cost and construction schedules for nuclear units.

7. The Commission convened a public hearing on this matter on October 2, 2012, which concluded on October 3, 2012.

8. No party presented any testimony or other evidence sufficient to overcome the Company’s affirmative testimony supporting the fact that the \$278.05 million in newly identified and itemized costs are prudent costs and are not in any way the result of SCE&G’s failure to manage the project prudently.

VI. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. The updated capital cost schedule contained in Hearing Exhibit No. 6 (CLW-1) reflects \$283 million in costs that have not previously been presented to the Commission for review and approval.

2. This \$283 million is comprised of approximately \$137.5 million attributable to Change Order No. 16, representing the settlement of several matters between Westinghouse/Shaw and SCE&G; \$131.6 million in newly identified and

itemized Owner's Cost; \$7.9 million in newly identified and itemized transmission costs; and \$5.9 million and \$0.1 million respectively, in costs associated with certain change orders that have been negotiated and identified to the EPC Contract for the Units.

3. The evidence in the record demonstrates that \$278.05 million in newly identified and itemized costs are the result of the normal evolution and refinement of construction plans and budgets for the Units and are not the result of imprudence on the part of SCE&G. At some point after the Phase II cyber-security costs are more definite and certain and when the issue of sharing these costs with other AP1000 plants has been determined, the Company may bring such costs to this Commission for further consideration.

4. These additional costs are reasonable, necessary and prudent costs that SCE&G is incurring as owner of the project to ensure that the project is constructed prudently, efficiently and economically, and to ensure that the Units can be operated and maintained safely and efficiently when they are completed.

5. The updated capital cost schedule contained in Hearing Exhibit No. 6 (CLW-1), as revised to exclude Phase II cyber-security costs, also appropriately reflects changes to the cash flow forecast that have resulted from changes in the expected timing of construction costs.

6. The evidence in the record demonstrates that the changes in project cash flows represent the reasonable and necessary updating of cash flow projections and do not represent imprudence on the part of the Company.

7. The updated milestone construction cost schedule contained in Hearing Exhibit No. 1 (SAB-3) reflects the delay in the substantial completion of Unit 2 until March 15, 2017, and the acceleration of Unit 3 to May 15, 2018. The evidence shows that the delay in the NRC issuing the COL was the principal cause of the nine-month delay of this critical path item.

8. The evidence in the record shows that the delay in the substantial completion date of Unit 2 and the acceleration of the completion of Unit 3 supports updating the construction milestones for the Units and is not the result of any imprudence on the part of SCE&G.

VII. Now, therefore, IT IS HEREBY ORDERED:

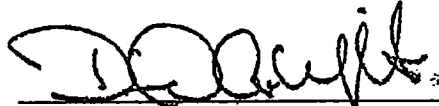
1. That the capital cost schedule set forth in Hearing Exhibit No. 6 (CLW-1), as modified by the Company according to the Commission directive in this case, and attached hereto as **Order Exhibit No. 1**, shall be the approved capital cost schedule for the Units until such time as the Commission approves a substitute schedule pursuant to S.C. Code Ann. § 58-33-270(E).

2. That the construction milestones schedule set forth in Hearing Exhibit No. 1 (SAB-3), attached hereto as **Order Exhibit No. 2**, shall be the approved construction milestone schedule for the Units until such time as the Commission approves a substitute schedule pursuant to S.C. Code Ann. § 58-33-270(E).

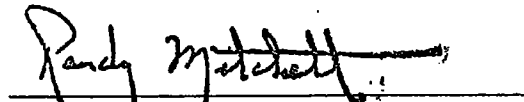
3. The future quarterly reports filed by SCE&G under S.C. Code Ann. § 58-33-277 shall reflect the modified schedules approved in this Order.

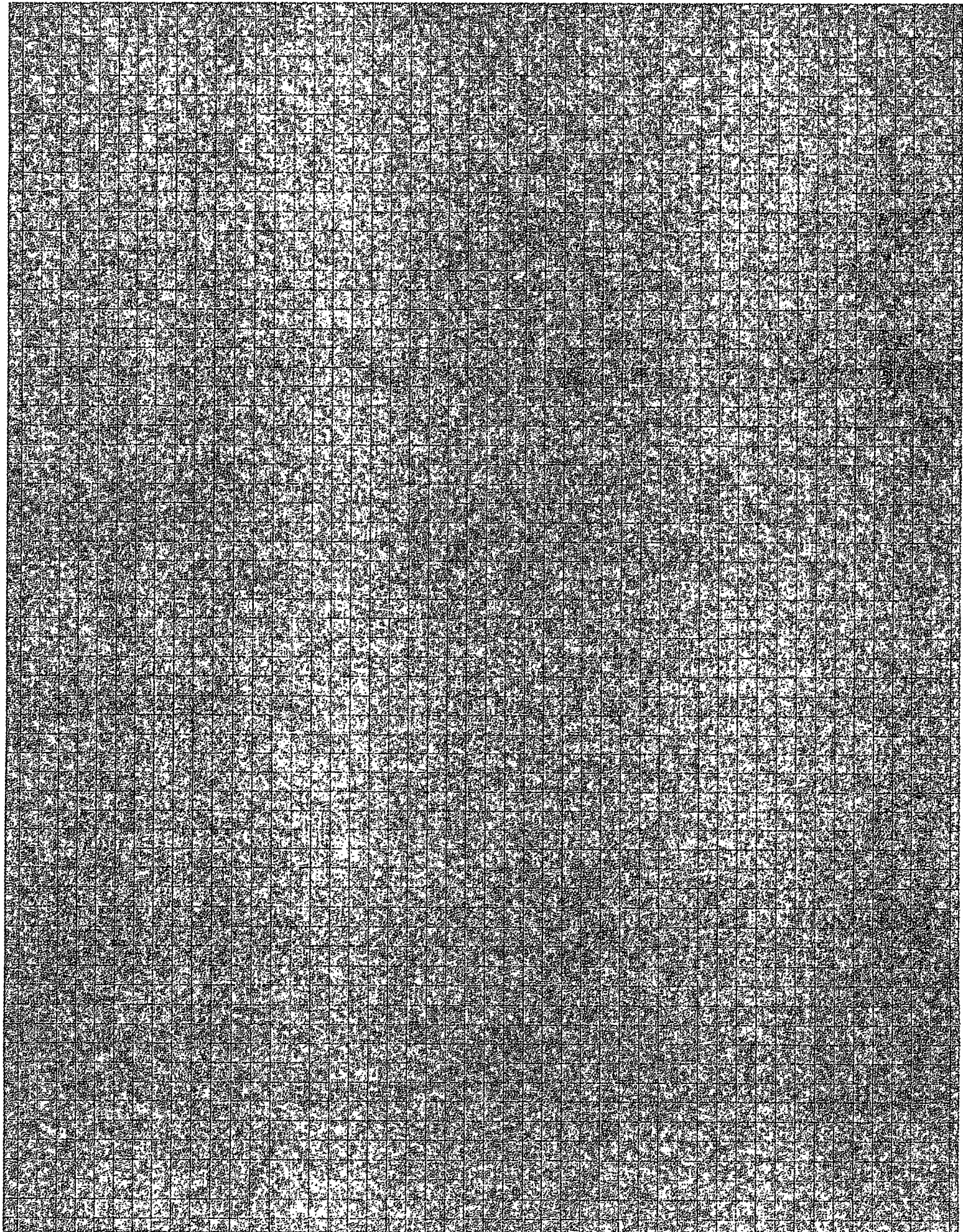
4. This Order shall remain in full force and effect until modified by a subsequent order of the Commission.

BY ORDER OF THE COMMISSION:


David A. Wright, Chairman

ATTEST:


Randy Mitchell, Vice Chairman
(SEAL)



BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2012-203-E - ORDER NO. 2013-5
FEBRUARY 14, 2013

IN RE: Petition of South Carolina Electric & Gas	)	ORDER DENYING
Company for Updates and Revisions to	)	PETITIONS
Schedules Related to the Construction of a	)	
Nuclear Base Load Generation Facility at	)	
Jenkinsville, South Carolina	)	

This matter comes before the Public Service Commission of South Carolina ("Commission") on two Petitions for Rehearing and/or Reconsideration of Order No. 2012-884, filed respectively in this docket by the Sierra Club and the South Carolina Energy Users Committee ("SCEUC").

On November 26, 2012, the Sierra Club filed a Petition for Rehearing or Reconsideration with the Commission in this docket. On November 28, 2012, SCEUC similarly filed with the Commission a Petition for Reconsideration. In each of these petitions (the "Petitions"), the petitioners (the "Petitioners") request that the Commission rehear or reconsider certain findings and conclusions as set forth in the Order approving SCE&G's request for updates and revisions to its capital cost and construction schedules, Order No. 2012-884, dated November 15, 2012 (the "Order"). The Petitions are without merit and are hereby denied.

I. Standards for Considering Petitions for Reconsideration and Rehearing

The purpose of a petition for rehearing and/or reconsideration is to allow the Commission the discretion to rehear and/or reexamine the merits of issued orders

pursuant to legal or factual questions raised about those orders by parties in interest, prior to a possible appeal. Pursuant to S.C. Code Ann. § 58-27-2310, “[n]o right of appeal accrues to vacate or set aside, either in whole or in part, an order of the commission . . . unless a petition to the commission for a rehearing is filed and refused” Additionally, a party cannot raise issues in a motion to reconsider that were not raised during the proceeding. See *Kiawah Prop. Owners Group v. Pub. Serv. Comm’n*, 359 S.C. 105, 113, 597 S.E.2d 145, 149 (2004); *Hickman v. Hickman*, 301 S.C. 455, 456, 392 S.E.2d 481, 482 (Ct. App. 1990); *Patterson v. Reid*, 318 S.C. 183, 185, 456 S.E.2d 436, 437 (Ct. App. 1995).

Under the operative Commission regulation, which is 10 S.C. Code Ann. Regs. § 103-825(4):

A Petition for Rehearing or Reconsideration shall set forth clearly and concisely:

- (a) The factual and legal issues forming the basis for the petition;*
- (b) The alleged error or errors in the Commission order;*
- (c) The statutory provision or other authority upon which the petition is based.*

Conclusory statements that amount to general and non-specific allegations of error do not satisfy the requirements of the rule. See *In re South Carolina Pipeline Company*, Docket No. 2003-6-G, Order No. 2003-641, at 6 (“[A] conclusory statement based upon speculation and conjecture is no evidence at all and is legally insufficient to support a [petition for reconsideration]”). While the requirements of specificity in post-trial motions are interpreted with flexibility, at minimum the decision-making body “must

be able to both comprehend the motion and deal with it fairly.” *See Camp v. Camp*, 386 S.C. 571, 575, 689 S.E.2d 634, 636 (2010).

Order No. 2012-884 is a comprehensive order setting forth sufficient findings and conclusions regarding the matters raised in this proceeding and the arguments of the Intervenors. That Order addressed all issues that were properly before the Commission in this docket.

II. The Errors Alleged in the Petition for Rehearing or Reconsideration

As an initial matter, the Sierra Club’s Petition consists solely of a list of errors alleged to have been committed by the Commission in Order No. 2012-884. The allegations of error are generally conclusory in nature and, in most cases, unsupported by any legal analysis and as such are insufficient to support a petition for rehearing. Notwithstanding the foregoing, the Commission will address the general principles contained in the Sierra Club’s petition herein. Further, the Commission will address each individual allegation of error by the Sierra Club and point out where each allegation has already been discussed and explained in Order No. 2012-884, and certain other pertinent orders, save the last general conclusory allegation. (See Appendix A to this Order, which is hereby deemed to be part of this Order as fully as if repeated herein verbatim.) The general discussion below and in Appendix A will also address the specific errors alleged by SCEUC.

In substance, the two Petitions allege two principal errors: First, the Petitions allege that SCE&G was required to have anticipated the cost adjustments that are at issue in this proceeding more than four and one-half years ago when SCE&G made its initial

filing under the Base Load Review Act, S.C. Code Ann. §§ 58-33-210, *et. seq.*, (“Base Load Review Act” or “BLRA”). Second, the Petitions allege that SCE&G was required to present in this docket a thorough evaluation of the prudence of the decision to continue to construct the new nuclear units (“Units”), and that the evidence presented here is not sufficient to meet that burden.

A. The Failure to Anticipate the Current Cost Adjustments in 2008

The Petitions allege that under the terms of the BLRA, SCE&G was required to anticipate the cost adjustments that are at issue in this proceeding when it made its initial BLRA filing in 2008. In Order No. 2012-884 at p. 67-68, the Commission responded to this allegation. For the reasons presented here, this allegation is without merit.

i. Structure and Proceedings Under the BLRA

The original BLRA review of the Units was held in 2008 in Docket No. 2008-196-E. In that docket, SCE&G presented its base cost forecasts for the Units and also provided detailed information about the risk factors it identified related to those forecasts. SCE&G further presented its best estimate of the amount of contingency funds that it anticipated to be sufficient to cover those risks.

In preparing its testimony in the 2008 hearing, the South Carolina Office of Regulatory Staff (“ORS”) conducted a full review and audit of SCE&G’s risk assessment and cost estimates. ORS did so using its own internal experts as well as independent experts with extensive experience in nuclear plant construction and major electric generation projects internationally. ORS’s testimony in that proceeding supported the reasonableness and prudence of the estimates and risk analysis presented by SCE&G.

After a vigorously contested hearing, the Commission determined that the cost estimates presented by SCE&G and supported by ORS were reasonable and prudent. The Commission approved those estimates in Order No. 2009-104(A). There was no suggestion in Docket No. 2008-196-E that the cost estimates presented there were anything but fair, complete, and thorough cost estimates based on the best information available to the utility at the time. Likewise, there is no credible evidence in this docket indicating otherwise.

Order No. 2009-104(A) was then appealed to the South Carolina Supreme Court on the theory that only costs that could be known with reasonable certainty and precision and that could be quantified to specific budgetary items could be included in approved BLRA estimates. The Court agreed and removed from the approved estimates for this project the contingency costs that SCE&G anticipated as likely to be incurred, but which were difficult to identify with certainty at that time.

In deciding to remove these contingency costs, the Court acknowledged that additional costs would likely be identified during the course of this and other similar projects. The Court found that such costs could properly be included in the approved estimates after the costs had been identified with specificity and were subject to Commission review provided for under S.C. Code Ann. § 58-33-270(E). *See South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, 388 S.C. 486, 496, 697 S.E.2d 587, 592 (2010). Therefore, the Court has adopted an interpretation of the BLRA that limits the costs that can be included in the BLRA cost forecasts to those costs that can be identified with reasonable certainty and specificity at the time an application

is filed. But the Court has balanced this ruling by affirming the flexibility that the BLRA allows the utility for updating cost forecasts later in the project as risks become better known and as costs become better quantified. Such a balance is required for the BLRA to function in a reasonable and effective way.

Petitioners, on the other hand, would have the Commission rule that utilities are imprudent for not including in their BLRA forecasts costs that were uncertain, hypothetical and unquantifiable at the time those forecasts were made. This position is inconsistent with the judicial interpretation of the BLRA that is reflected in *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, *supra*.

Under Petitioners' approach, the Commission is invited to rule, among other things, that SCE&G should have included in its 2008 cost forecasts the following:

- i. the effects on contractors' labor costs of the 2010 federal Health Care and Education Reconciliation Act (Change Order 12),
- ii. the impact on nuclear staffing and emergency planning requirements of the 2011 Fukushima event (Emergency Planning/Health Physics),
- iii. the impact on equipment and software costs of the recent emergence of cyber-security threats to the electric system (Change Order 14),
- iv. the possibility that, in the period 2008-2012, the Nuclear Regulatory Commission (NRC) and the

- industry might increase standards for the licensing and training of nuclear operators and craft workers (Operator/Training Margin, Timing Variance to Support Craft),
- v. the possibility that the economic recession that began in late 2008 would result in other utilities not proceeding with new units and so not sharing common engineering costs for AP1000 projects (APOG/Plant Programs/Procedures),
 - vi. the costs and time required for complying with NRC aircraft impact standards for nuclear reactors that were not issued until 2009 (Change Order 16),
 - vii. the fact that, in 2011-2012, Westinghouse Electric Company, LLC and the Shaw Group decided that stronger steel was required for certain modules used in the Units (Change Order 16), and
 - viii. the fact that, after excavation conducted during 2009-2011, rock conditions at the site might be found to be different from what pre-excavation drilling showed (Change Order 16).

The Petitioners' approach would require the Commission to engage in a level of speculation that is incompatible with the purposes and intent of the BLRA. Furthermore,

given the speculative nature of the analysis that would be required, Petitioners' interpretation of the BLRA would make the statute very difficult for this Commission to apply in practice.

Further, the Petitioners' interpretation of the BLRA which necessitates giving effect to one section of the law wherein the capital costs are first determined, while ignoring another section of the law for revisions to the capital costs, violates the rule of statutory construction set out by the Court of Appeals. That Court has held that, in construing statutory language, the statute must be read as a whole, and sections which are part of the same general statutory law must be construed together and each one given effect, if it can be done by any reasonable statutory construction. *Tillotson v. Keith Smith Builders*, 357 S.C. 554, 593 S.E. 2d 621 (Ct. App. 2004); *Corbett v. The City of Myrtle Beach*, 336 S.C. 601, 521 S.E. 2d 276 (Ct. App. 1999). In this case, the Petitioners give credence to the establishment portion of the Base Load Review Act (Section 58-33-275) while ignoring the revision provision (§ 58-33-270 (E)) and the Supreme Court's holdings in SCEUC's own appeal regarding the availability of requests for revisions to the approved capital costs. See *South Carolina Energy Users Committee v. South Carolina Public Service Commission*, *supra*.

The completeness and prudence of the utility's original BLRA cost forecasts were fully addressed in Order No. 2009-104(A). But putting that order aside, the preponderance of evidence in this docket establishes that each of the cost adjustments presented here were not known or reasonably knowable when prior BLRA petitions were before this Commission. In this docket, SCE&G has presented a detailed accounting of

the changes that make up its request for a \$283 million adjustment in cost schedules and specific testimony about how the requirements that led to this adjustment have arisen. This evidence shows that the requested cost adjustments arise out of changes in laws, changes in regulations, subsequent regulatory decisions, changes or evolutions in designs, emerging information and analysis as to operations, staffing and facilities, changed conditions or other matters that have arisen or become known since the prior proceedings. This evidence establishes that the adjustments at issue in this proceeding were not known or knowable with certainty, clarity or specificity when prior BLRA proceedings were heard. As such, under the reasoning of the Court in *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, *supra*, these costs could not properly be included in the BLRA forecasts that were approved in prior orders, and the Company was not imprudent for not including them in prior forecasts.

ii. Standard of Review Under S.C. Code Ann. § 58-33-270(E)

In its review of the evidence presented in this proceeding, the Commission has relied on the standards set out in S.C. Code Ann. § 58-33-270(E). This is the provision of the BLRA that permits utilities to seek modifications of cost forecasts that the Commission has previously approved under the BLRA.

S.C. Code Ann. § 58-33-270(E) reads as follows:

The commission shall grant the relief requested [i.e., a modification of forecasted cost schedules] if, after hearing, the commission finds . . . that the changes [to those schedules] are not the result of imprudence on the part of the utility.

S.C. Code Ann. § 58-33-270(E)(1).

Petitioners assert that S.C. Code Ann. § 58-33-275(E) contains a different and higher standard than that contained in S.C. Code Ann. § 58-33-270(E). Petitioners assert that it was an error for the Commission to rely on S.C. Code Ann. § 58-33-270(E) and not on S.C. Code Ann. § 58-33-275(E) in deciding this matter. The statutory provision on which the Petitioners rely is found in a different section of the BLRA. The principal focus of that section is to establish the final and binding nature of a BLRA order in the context of requests for revised rates or other rate relief. See S.C. Code Ann. § 58-33-275(A), (B), (C); S.C. Code Ann. § 58-33-280(A), (B), (J)(1); S.C. Code Ann. § 58-27-860. This provision instructs the Commission on how to proceed in cases where a party demonstrates that a deviation from approved cost forecasts was caused by utility imprudence. In such cases, S.C. Code Ann. § 58-33-275(E) provides that the Commission “*may* disallow the additional capital costs that result from the deviation but only to the extent that the failure by the utility to anticipate or avoid the deviation, or to minimize the resulting expense, was imprudent considering the information available at the time that the utility could have acted to avoid the deviation or minimize its effect.” S.C. Code Ann. § 58-33-275(E) (emphasis supplied). Thus, where additional costs due to imprudence are shown, S.C. Code Ann. § 58-33-275(E) provides the Commission with discretion to isolate and remove the imprudent costs presented in a revised rates proceeding or general rate proceeding without otherwise jeopardizing the binding nature of the BLRA Order as to other costs.

Contrary to Petitioners’ suggestion however, S.C. Code Ann. § 58-33-275(E) does not impose a new, higher, or different standard for judging prudence than that contained

in S.C. Code Ann. § 58-33-270(E). S.C. Code Ann. § 58-33-275(E) embodies the established rule that prudence is not to be judged by hindsight but must be judged based on the information available to the utility at the time that meaningful decisions can be made to avoid or minimize costs. Contrary to Petitioners' assertions, S.C. Code Ann. § 58-33-270(E) does not create a special duty to identify costs in initial BLRA proceedings that is different from the duty that exists under the standard prudence rule. As indicated above, in Order No. 2009-104(A), the Commission found after a hearing that the cost projections presented in Docket No. 2008-196-E were reasonable and prudent considering the information available to SCE&G at that time. Nothing in S.C. Code Ann. § 58-33-275 indicates that S.C. Code Ann. § 58-33-275(E) is intended to create a different standard of review to override the prudence standard contained in S.C. Code Ann. § 58-33-270(E).

The Commission has reviewed S.C. Code Ann. § 58-33-270(E) and S.C. Code Ann. § 58-33-275(E) in light of the structure of the BLRA and the policies underlying it. The Commission finds that, in Order No. 2012-884, it appropriately applied the standards contained in S.C. Code Ann. § 58-33-270(E) to its evaluation of the evidence in this proceeding.

B. The Prudence of Continuing the Nuclear Project

The Petitions further allege that, in this docket, SCE&G was legally required to present a reassessment of the prudence of continuing to build the two Units as a prerequisite to modifying the approved cost schedules, including a consideration of whether building one nuclear unit instead of two units would have been prudent. In its

evidence in the proceeding, SCE&G presented two analyses prepared by Dr. Joseph Lynch supporting the economic justification of continuing to build the Units as opposed to abandoning them in favor of what was stated as the next-best alternative, which was natural gas fired combined-cycle capacity. The Petitions allege that these two analyses were not sufficient.¹

As stated in Order No. 2012-884, the Commission does not believe that SCE&G was required to present the prudence analysis that the Sierra Club alleges was necessary. As stated in Order No. 2012-884, such an analysis was not required because of (a) the binding nature of the initial BLRA decision under S.C. Code Ann. § 58-33-275(A), and (b) the terms of S.C. Code Ann. § 58-33-275(D) which preclude consideration of changes in fuel prices in reassessing the binding nature of BLRA orders. As to the later point, the recent decline in natural gas prices was the basis for the Sierra Club's claim that a reassessment of the prudence of continuing to build the Units was required. This puts that claim squarely at odds with S.C. Code Ann. § 58-33-275(D), which states that changes in fuel costs will not be considered in conducting any evaluation under the Base Load Review Act.

However, the issue of whether or not an analysis was required is moot because SCE&G prepared the analysis that the Sierra Club requested and presented it in two forms in its rebuttal and supplemental rebuttal testimony. The Petitioners have had the opportunity to review the analyses, examine SCE&G's witnesses concerning them, and

¹ This issue was not raised by SCEUC either at hearing or in its post hearing brief in the form of a proposed Order Denying Petition for Updates and Revisions to Schedules, dated October 26, 2012, and is therefore, deemed to be waived by SCEUC. See p. 16 *infra* for relevant case law.

file surrebuttal testimony and supplemental surrebuttal testimony concerning them. In this context, it would be meaningless to grant rehearing on the question of whether such an analysis was required. The relief requested has already been obtained. The Commission has reviewed the analyses that Dr. Lynch presented with the same care and attention that would have been given if there was an express statutory requirement for SCE&G to present such information. The Commission has determined that Dr. Lynch's analyses amply support the decision to continue constructing the Units. Weighing Dr. Lynch's analyses and testimony against the contrary evidence provided by the Sierra Club's witness Dr. Cooper, the Commission finds Dr. Lynch's analyses and testimony to be credible and convincing. The preponderance of the evidence fully supports the prudence of continuing to build the Units.

The Sierra Club also questions the methodological sufficiency of Dr. Lynch's second analysis. As a factual matter, the Commission finds that both analyses he presented were methodologically sound and sufficient to demonstrate the prudence of continuing to construct the Units. In modeling gas scenarios in his second analysis, Dr. Lynch assumed two combined-cycle natural gas plants would come on line at the same time, as the Units were scheduled to do so in the nuclear scenarios, *i.e.*, in 2017 and 2018. He assumed that these combined-cycle gas units would provide the same generating capacity as the nuclear Units. As a factual matter, the Commission does not find credible the Sierra Club's claims that the analysis would lead to different conclusions if the timing of the construction of the natural gas plants were adjusted. With the addition of either the new natural gas capacity or the nuclear capacity, SCE&G's reserve margin does not

exceed the established range during the planning period. This means that, under either scenario, new generation is needed in the years and amounts specified. Therefore, there is no factual basis to assume that, if a natural gas resource strategy is assumed, the addition of natural gas capacity can be delayed.

The Commission further accepts Dr. Lynch's testimony that it is not possible to create efficiencies in the natural gas resource plan by down-sizing the potential gas units. As Dr. Lynch testified, the blocks of natural gas fired generation Dr. Lynch assumed in his analysis were as small as feasible for combined-cycle natural gas units. [Tr. at 925-926]. Accordingly, whether gas or nuclear capacity is added, the blocks of capacity added and the timing of capacity added will be the same. There is no factual basis to assume that switching to a natural gas resource strategy would allow SCE&G to delay constructing needed generation resources or to construct them in smaller increments.

The Commission also does not find credible the Sierra Club's claim that running additional scenarios to assess the impact of energy conservation or alternative energy sources might lead to different results. As the record amply demonstrates, the generation that SCE&G's system needs is dispatchable base load or intermediate generation. The evidence shows that energy efficiency resources and other alternative energy resources, such as wind and solar, are important and potentially beneficial supplements to base load or intermediate generation, but they are not substitutes for it. The cost limitations and availability limitations of these alternative resources and their insufficiency to replace dispatchable base load and intermediate generation units are amply discussed in the evidence presented in this docket as well as in Docket 2008-196-E.

More importantly, the Commission finds that the decision to proceed with the construction of the Units does not and should not depend solely on the current price forecasts for natural gas supplies. This is a factual finding based on the evidence presented in this docket by Mr. Marsh, Mr. Byrne and Dr. Lynch as to the uncertainties of such forecasts and their changing nature. A similar result is reached based on S.C. Code Ann. § 58-33-275(D). But the Commission reaches the same result on a purely factual basis whether or not that statute is considered.

As to this later point, SCE&G's customers will benefit if SCE&G can construct a generating system that reflects a balanced portfolio of plants, with a balanced mix of fuel sources and environmental risks. The Commission finds that, as a factual matter, adding nuclear generation accomplishes that goal.

The Sierra Club argues that Dr. Lynch's analyses might have reached a different result had he considered alternative prices for nuclear construction. The Commission finds that this argument is without merit. The preponderance of the evidence shows that, even with today's exceptionally low natural gas prices, completing nuclear generation is the most economical choice for SCE&G. The evidence on the record shows that it would require changes in the comparative costs of nuclear and gas generation that are well beyond anything suggested in the record here for that advantage to be reversed. But even if it could be shown that natural gas generation had some cost advantage over nuclear generation due to current gas prices, the risks that those prices would change as well as the risks inherent in SCE&G continuing and deepening its reliance on fossil fuels would have to be carefully considered before any change in the construction plan would be

warranted. The preponderance of the evidence shows that the price risks and environmental risks of expanded reliance on fossil fuel generation resources are material and substantial.

C. Miscellaneous Allegations

In its Petition, at pp. 11-12, SCEUC seeks to raise issues related to the expiration of 250 megawatt capacity sales contract between SCE&G and a North Carolina wholesale supplier. Issues related to this contract were raised and fully addressed in Docket 2012-218-E. As indicated in that docket, the expiration of the contract has been reflected in SCE&G's projections of future capacity needs under its Integrated Resource Plan ("IRP") which is the data Dr. Lynch used in performing his analyses. Accordingly, the expiration of this contract is already accounted for in Dr. Lynch's analyses. In the context of the present docket, until the filing of the SCEUC's Petition, neither SCEUC nor any other party sought to present evidence or argument concerning the expiration of this contract in this proceeding. This matter was not raised prior to the filing of these Petitions, and it is not properly before the Commission at this time. This argument is waived. See *Kiawah Prop. Owners Group v. Pub. Serv. Comm'n*, *supra*; *Hickman v. Hickman*, *supra*; *Patterson v. Reid*, *supra*, (holding that a party cannot raise issues in a motion to reconsider that were not raised during the proceeding).

The Petitioners alleged that SCE&G was imprudent in filing the original BLRA proceeding before the final round of amendments to the AP1000 design control documents ("DCD") were reviewed and approved. This issue was extensively litigated in Docket No. 2008-196-E. As indicated in that docket, the NRC had granted final approval

for the design of the AP1000 reactor well before 2008. That approval included the DCD revisions up to and including DCD Revision 15. In 2008, additional amendments to the DCD were expected to improve the reactor's resistance to aircraft impacts but cost, timing, and other effects of those revisions could not be known until the NRC issued its final aircraft impact rule and design work to meet those requirements was completed.

In its testimony at the 2008 hearing, the Company provided evidence that it was neither feasible nor economical to wait for those additional DCD revisions to be finalized before proceeding with its BLRA application. Failure to proceed at that time would have involved the loss of favorable pricing terms and other terms in the Engineering, Procurement, and Construction (EPC) Contract, the loss of special federal production tax credits for new nuclear construction, the inability to proceed with the plan for financing construction of the Units, and the necessity from a timing standpoint to abandon the nuclear construction plan and meet the Company's base load generation needs with combined-cycle units. At the time of the initial BLRA proceeding, combined-cycle gas units were the only alternative base load or intermediate load resource that could be constructed rapidly enough to meet system needs.

The Company's testimony concerning the need to file the BLRA petition in 2008 was credible. In this proceeding, it is not appropriate for the Commission to reopen its earlier approval of that decision. Furthermore, no credible evidence has been presented in this docket to indicate, in light of the factors listed above, that it was imprudent to proceed with the initial BLRA filing at the time that the Company did.

SCEUC raises two further issues with our original Order in this case. SCE&G

used the macro-corridor approach in quantifying the environmental impacts of the transmission aspects of this project. SCEUC asserts that this contributed to the delay in issuing the Combined Operating License (COL) for the Units. SCEUC further asserts that SCE&G's eventual decision to minimize environmental impacts by using existing rights of way for constructing the lines in question is the cause of some part of the increase in transmission costs at issue in this proceeding. These two points constitute conclusory assertions made by SCEUC without evidentiary support. Neither of these points is supported by the evidence of record in this proceeding. The SCEUC has not pointed to any evidence of record supporting these assertions in its Petition. The Commission finds them to be without merit.

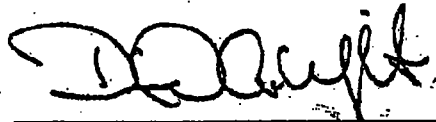
III. CONCLUSION

For the foregoing reasons, and the reasons discussed in the Appendix below, this Commission denies the relief sought by the Sierra Club and the South Carolina Energy Users Committee in their Petitions and such Petitions are denied in their entirety. (See Appendix A below for a discussion of the specific allegations of error propounded by the Sierra Club and the location of already published findings regarding the majority of those allegations.)

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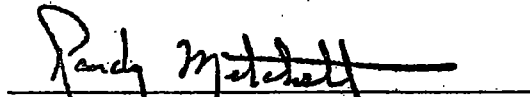
This Order shall remain in full force and effect until further order of the Commission.

BY ORDER OF THE COMMISSION:



David A. Wright, Chairman

ATTEST:



Randy Mitchell, Vice Chairman
(SEAL)

Appendix A

Specific Allegations of Error of the Sierra Club and Locations of Already Published Findings on Those Allegations in Order No. 2012-884 and other Orders

- 1. The Commission erred in overlooking and misapprehending the nature and scope of the authority granted it by statute to modify its Initial Base Load Review Order, Order No. 2009-104 (A), applicable to this project.**

This allegation is conclusory and fails to state how the Commission overlooked and misapprehended the nature and scope of its authority. However, the nature and scope of the Commission's authority in this case is properly described at Order 2012-884, page 13.

- 2. The Commission erred in failing to properly apply the provisions of SC Code Ann. § 58-33-275 to SCE&G's Petition to include additional capital costs estimates in its Base Load Review Order.**

This allegation is conclusory, since it fails to state how the Commission failed to properly apply the law to SCE&G's Petition. The Commission discusses the concept, however, throughout the Order.

- 3. The Commission erred in failing to conclude here, where it is proven by a preponderance of evidence that there has been a material and adverse deviation from the approved schedules, estimates and projections set forth in the Base Load Review Order, and that it must disallow the additional capital costs that result from the deviation to the extent that the failure by the Utility to anticipate or avoid the deviation or to minimize the resulting expense was imprudent. S.C. Code Ann. § 58-33-275(E).**

This allegation goes to the Commission's basic interpretation of the Base Load Review Act, and where and when various sections of it are applicable. In this case, the Commission was presented with a list of new capital costs with an explanation that the costs occurred after the date of the original Base Load Order. Accordingly, this Commission held in Order No. 2012-884 that the revision portion of the Base Load Review Act, section 58-22-275(E) applied. See all of Order No. 2012-884, and, particularly, the explanation given on page 72 of that Order. Further, this principle is thoroughly discussed in the body of the present Order.

- 4. The Commission erred in failing to conclude that SCE&G could, or should have anticipated or avoided the additional capital costs in question at the time of its Initial Base Load Review Act (BLRA) application.**

This allegation of error concerns one of the major themes in the case. On pages 33-68 of Order No. 2012-884, the Commission discusses the additional proposed capital costs and why they should be accepted. See also the extensive discussion throughout the present Order.

5. The Commission erred in failing to conclude that the evidence in the record compels a finding that in its rush to construct the nuclear plants, SCE&G sought and obtained its Base Load Review Order based on an incomplete unapproved design for the Westinghouse AP 1000 model nuclear plant, while failing to anticipate and include adequate safeguards to avoid excessive additional capital costs.

This issue was discussed extensively on pp. 63-64 of Order No. 2009-104(A). The matter is also further elucidated on pp. 34-36 of Order No. 2012-884, and pp. 16-17 of the present Order.

6. The Commission erred in finding and concluding that the additional capital costs associated with Change Order 16 are reasonable and prudent and comport with the terms of the BLRA; where such costs were anticipated, or should have been anticipated by SCE&G in its Initial Base Load Review Act application, and are, therefore, imprudent under the BLRA. SCE&G assumed the risk of the additional costs associated with Change Order 16 which are not recoverable under the BLRA. §§ 58-33-250 (1), 58-33-275 (E).²

This allegation is conclusory. This issue was discussed extensively on pp. 33-42 of Order No. 2012-884. There is also a general discussion in this Order at pp. 6-9 about the fact that these costs could not have been anticipated at the time of Order No. 2009-104(A). There is no evidence that SCE&G should have assumed the risk for the additional costs at that time.

7. The Commission erred in finding and concluding that the additional \$131.6 million in owner's costs requested in this docket are reasonable and prudent and comport with the terms of the BLRA; and in failing to find and conclude that SCE&G should have anticipated or avoided the additional \$131.6 million in owner's costs it seeks recovery of in this Docket.³

This allegation is conclusory. This issue was discussed extensively on pp. 42-58 of Order No. 2012-884. Further, there is also a general discussion in the present Order at pp. 6-9 about the fact that these costs could not have been anticipated or avoided earlier.

8. The Commission erred in finding and concluding the additional capital costs associated with transmission costs requested in this docket are reasonable and prudent and comport with the terms of the BLRA. The additional transmission costs could and

² See also SCEUC Petition, p. 8, Paragraph 4 a. Although the SCEUC allegation is not conclusory, it is erroneous as per the discussion herein. Further, SCEUC appears to allege for the first time that SCE&G failed to demonstrate that the settlement agreement among it, Westinghouse, and Santee Cooper was prudent and reasonable. In any event, this allegation is without merit, as explained in Order No. 2012-884 at pp. 38-39.

³ See also SCEUC Petition, p. 9, Paragraph 4 b. Although the SCEUC allegation is not conclusory, it is erroneous as per the discussion herein.

should have been anticipated or avoided at the time of the Company's initial BLRA Application.⁴

This allegation is conclusory. The issue was discussed extensively on pp. 58-63 of Order No. 2012-884 and at pp. 6-9 of the present Order.

9. The Commission erred in finding and concluding that the additional costs sought for Cyber Security, Change Order 12 and Change Order 15 in this docket are reasonable and prudent and comport with the terms of the BLRA. The additional costs sought for Cyber Security, Change Order 12 and Change Order 15 could and should have been anticipated or avoided at the time of the Company's initial BLRA Application.⁵

This allegation is conclusory. The issue was discussed extensively on pp. 63-68 of Order No. 2012-884. See also pp. 6-9 of the present Order.

10. The Commission erred in failing to conclude that the BLRA requires consideration of the prudence of continuing to incur capital costs for a nuclear project where the evidence of material changed conditions compels the conclusion that incurring additional capital costs for constructing the project is now imprudent and where such costs can be avoided by abandoning the nuclear project in favor of a less costly alternative energy resource plan.

This allegation is conclusory and merely expresses a contrary viewpoint to the Commission's, which was based on the evidence before it. The Commission discussed the issue extensively on pp. 13-15 and on pp. 32-33 of Order No. 2012-884.

10. The Commission erred in failing to conclude that the evidence in the record of material changed conditions regarding the costs of this project and feasible alternatives compels a finding that continuing to incur capital costs for the nuclear project is now imprudent where such costs can be avoided by abandoning the nuclear project in favor of a less costly alternative energy resource plan.⁶

This allegation is conclusory and merely expresses a contrary viewpoint to the Commission's, which was based on the evidence before it. The Commission discussed the issue extensively on pp. 13-15 and 32-33 of Order No. 2012-884.

⁴ See also SCEUC Petition, p. 10, Paragraph 4 c. Although the SCEUC allegation is not conclusory, it is erroneous, as per the discussion herein.

⁵ See also SCEUC Petition, p. 10, Paragraph 4 d. Although the SCEUC allegation is not conclusory, it is erroneous, as per the discussion herein.

⁶ The Petition for Rehearing or Reconsideration filed by the Sierra Club had two allegations of error labeled "10." For consistency, we have replicated this numbering scheme here.

11. The Commission erred in interpreting the BLRA to preclude the consideration of “changes in fuel costs” in considering the prudence of abandoning construction of the nuclear project in favor of a less costly alternative energy resource plan.

This allegation is directly contrary to S.C. Code Ann. § 58-33-275(D) (Supp. 2012) and is discussed on page 17 of Order No. 2012-884.

12. The Commission erred in interpreting the BLRA to authorize the “routine” filing of capital cost update proceedings instead of requiring the utility to anticipate and avoid incurring imprudent costs to the detriment of ratepayers.

S.C. Code Ann. § 58-33-270(E) (Supp. 2012) states that “As circumstances warrant, the utility may petition the commission....for an order modifying any of the schedules, estimates....that form part of any base load review order issued under this section. ..(emphasis added).” Therefore, the statute allows a company to file at any time that circumstances may warrant it, and the statute goes on to state that the Commission shall grant the relief as requested, as long as the utility can show that the changes “are not the result of imprudence on the part of the utility....” The utility is consistently under a duty to show that expenditures on a facility are prudent. The Commission found that the evidence presented by SCE&G in this case “amply establishes the prudence of continued investment in the project under construction.” See Order No. 2012-884 at 32 for further discussion.

13. The Commission erred in interpreting the BLRA to preclude protecting ratepayers from imprudent capital costs of continued plant construction while authorizing the utility to recover even the costs of an abandoned nuclear plant project.

The Petitioner joins two concepts in this allegation that are not logically connected. However, we will attempt to discuss. First, the BLRA does not preclude protection of the ratepayers if a utility imprudently incurs costs. If this occurs, the Commission does not have to grant the relief requested on a petition for a change in estimates or schedules. See S.C. Code Ann. § 58-33-270(E) (Supp. 2012). See also S.C. Code Ann. § 58-33-275(E) (Supp. 2012) which states that the Commission may disallow additional costs incurred as a result of a material or adverse deviation from a schedule or estimate, if the evidence shows that the failure to minimize the expense was imprudent considering the information available at the time that the utility could have acted to avoid the deviation or minimize the expense. S.C. Code Ann. § 58-33-280(K) (Supp. 2012) governs the costs of abandoned plants. When a plant is abandoned after a base load order has been issued approving recovery, the capital costs and AFUDC (Allowance for Funds Used During Construction) related to the plant shall nonetheless be recoverable, provided that the utility can prove by a preponderance of the evidence that the decision to abandon construction of the plant was prudent. Therefore, under the BLRA, prudent costs are recoverable, even with a plant abandonment, while imprudent costs are not. The BLRA

guards ratepayers from an attempt by utilities to recover imprudent costs. The Commission has always been governed by this principle in BLRA cases, and continued to be so governed in this case. See discussion in Order No. 2012-884 at 68.

14. The Commission erred in concluding that the construction of the nuclear Units should continue and that the additional capital costs and schedule changes are not the result of imprudence on the part of SCE&G.

This allegation is simply the opposite of the conclusion that the Commission ultimately reached, after weighing all the evidence in the case. The Petitioner does not furnish any evidence or reasoning for this allegation of error. The Commission's reasoning is explained thoroughly in Order No. 2012-884, especially at page 32 and page 69.

15. The Commission erred in rejecting the evidence presented by the Sierra Club that the nuclear project was no longer prudent in light of available alternatives and finding that the evidence presented by SCE&G amply establishes the prudence of continued investment in the nuclear project.

This allegation simply presents a repetitive conclusory statement, with no supporting evidence stated. Again, the Commission explained thoroughly why it rejected the evidence presented by the Sierra Club in Order No. 2012-884, especially at page 14 and page 32.

16. The commission⁷ erred in finding that the evidence presented in this docket demonstrates that additional nuclear generation will bring considerable benefits of fuel diversity and the flexibility to respond to future environmental regulations to SCE&G's generation portfolio across a broad range of possible scenarios for fuel costs and environmental regulations.

Again, the allegation is conclusory, and without supporting evidence. Further, it ignores this Commission's full explanation for its finding in this area, found in Order No. 2012-884 at 26 and 33.

17. The commission erred in finding that the Company made an affirmative and sufficient demonstration of the prudence of its nuclear construction program.

As stated in Order No. 2012-884, the Sierra Club appears to argue that, as a condition of approval of the updated capital cost schedules at issue, the issue of whether nuclear generating resources remain the appropriate choice for SCE&G should be reopened.

⁷ The Petition for Rehearing or Reconsideration filed by the Sierra Club made reference to both the "commission" and the "Commission" in its allegations of error. For consistency, we have replicated this style here.

Order at 15. S.C. Code Ann. § 58-33-275(B) (Supp. 2012) states that the original determination (here made in Order No. 2009-104(A)) may not be challenged or reopened in any subsequent proceeding. SCE&G takes the position, and correctly so, that the issue before the Commission in this proceeding was changes to costs and schedules under S.C. Code Ann. § 58-33-270(E) (Supp. 2012). However, even so, this Commission examined the evidence in the present case and affirmed its prior position taken in Order No. 2009-104(A), that the Company made an affirmative and sufficient demonstration of the prudence of its nuclear construction program, as well as the prudence of the changes to costs and schedules proposed by the Company. See Order No. 2012-884 at 18.

- 18. The Commission erred in concluding that the evidence in the record demonstrates that \$278.05 million in newly identified and itemized costs are the result of the normal evolution and refinement of construction plans and budgets for the Units and are not the result of imprudence on the part of SCE&G.**

In effect, the entirety of Order No. 2012-884 addresses this allegation, wherein the Commission weighed the evidence before it, and reached the conclusion summarized in Order No. 2012-884, beginning at 68. Again, this is a conclusory allegation, with no evidence cited to support it.

- 18. The Commission erred in concluding that these additional costs are reasonable, necessary and prudent costs that SCE&G is incurring as owner of the project to ensure that the project is constructed prudently, efficiently and economically, and to ensure that the Units can be operated and maintained safely and efficiently when they are completed.⁸**

Again, the entirety of Order No. 2012-884 addresses this allegation, leading up to the conclusion beginning at 68. No evidence is cited to support this conclusory allegation.

- 19. The Commission erred in concluding that the evidence in the record shows that the delay in the substantial completion of Unit 2 and the acceleration of the completion of Unit 3 supports updating the construction milestones for the Units and is not the result of any imprudence on the part of SCE&G.**

This conclusory allegation is discussed specifically in Order No. 2012-884 at 73, paragraphs 7 and 8. Clearly, the delay in the substantial completion of Unit 2 was principally caused by a delay in the Nuclear Regulatory Commission's issuance of the Combined Operating License ("COL") for the V.C. Summer Units. Further discussion is found on page 68 of that Order. The evidence showed that, once construction of Unit 2 was delayed, the construction milestones could be modified and construction could be accelerated for Unit 3. Order at 69.

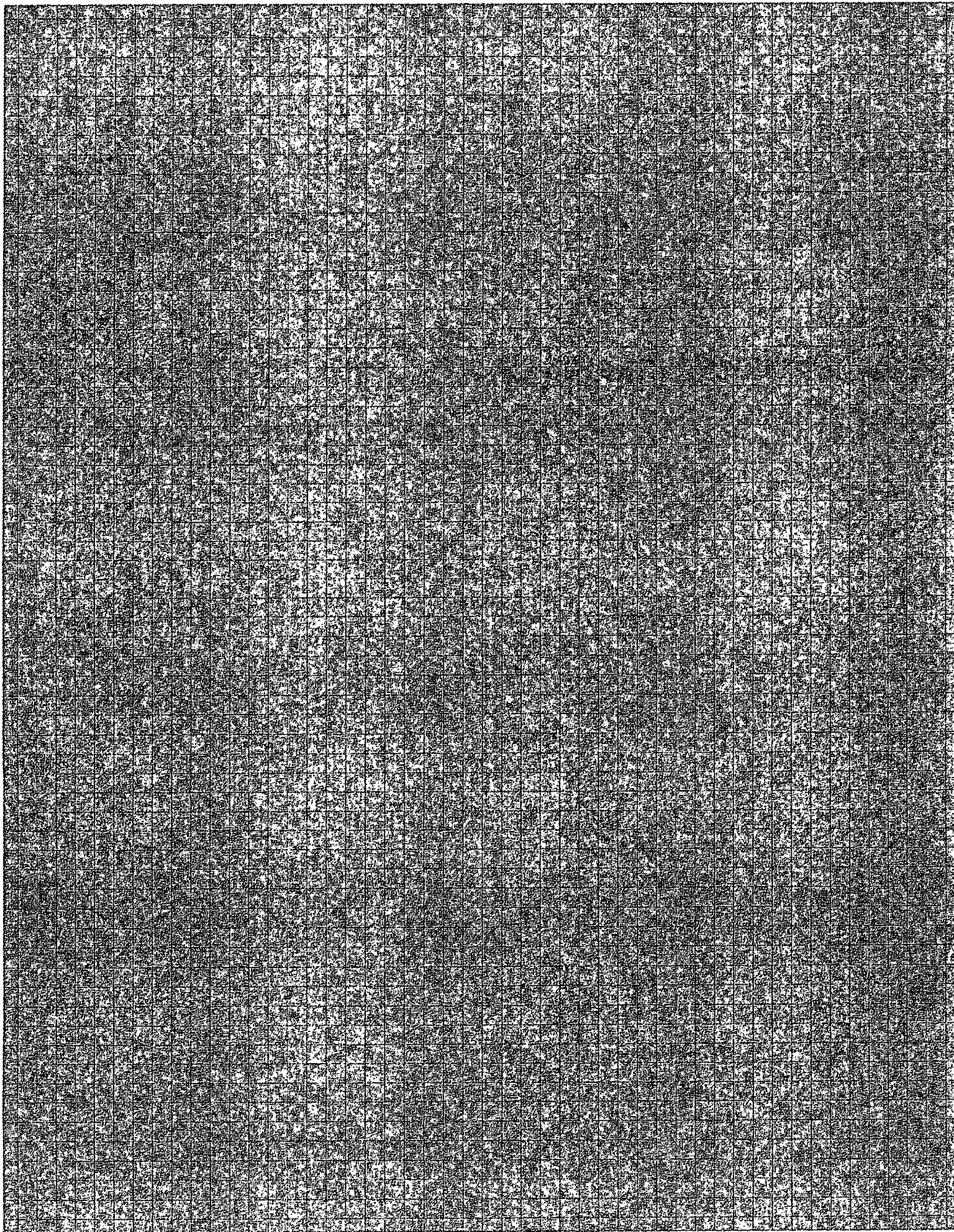
⁸ The Petition for Rehearing or Reconsideration filed by the Sierra Club had two allegations of error labeled "18." For consistency, we have replicated this numbering scheme here.

20. The Commission erred, based on the evidence presented by Sierra Club and its expert, Dr. Mark Cooper, in failing to require SCE&G to undertake a thorough evaluation of the prudence of abandoning the nuclear project in favor of a less costly alternative energy resource plan.

A thorough analysis and evaluation of this conclusory allegation is found in Order No. 2012-884 at 18-33. This is one of the major issues in the case, and extensive evidence is cited to support the Commission's conclusion in that Order.

21. The Commission erred in its Order approving the Petition by SCE&G where said Order is arbitrary, capricious, an abuse of discretion, clearly erroneous, unsupported by substantial evidence, in violation of constitutional or statutory provisions, made upon unlawful procedure or affected by other error of law.

This conclusory allegation fails to state with specificity what the Commission has allegedly done to violate the specific points listed, which are actually found in the Administrative Procedures Act at S.C. Code Ann. § 1-23-380 (5) (Supp. 2012). In point of fact, even if the Sierra Club had stated its allegations with more specificity, the points listed are only applicable to judicial review upon exhaustion of administrative remedies (See S.C. Code Ann. § 1-23-380 (Supp. 2012)) and are not specifically applicable for petitions for rehearing before the Commission, such as those presently under review herein. (See S.C. Code Ann. § 58-27-2150 (1976)). There is no reference to these points in Order No. 2012-884.



BEFORE
THE PUBLIC SERVICE COMMISSION
OF
SOUTH CAROLINA
DOCKET NO. 2012-203-E

In Re: Petition of South Carolina	)	<u>PETITION FOR UPDATES AND</u>
Electric & Gas Company for Updates	)	<u>REVISIONS TO THE CAPITAL</u>
and Revisions to Schedules Related to	)	<u>COST SCHEDULE AND THE</u>
the Construction of a Nuclear Base Load	)	<u>CONSTRUCTION SCHEDULE</u>
Generation Facility at Jenkinsville,	)	
South Carolina	)	

South Carolina Electric & Gas Company ("SCE&G" or the "Company") hereby petitions the Public Service Commission of South Carolina (the "Commission") for an order approving an updated capital cost schedule and updated construction schedule for the construction of two 1,117 net megawatt nuclear units (the "Units") to be located at the V. C. Summer Nuclear Station site near Jenkinsville, South Carolina. This petition (the "Petition") is filed pursuant to the provisions of the Base Load Review Act ("BLRA"), S.C. Code Ann. § 58-33-270(E) (Supp. 2011). In accordance with the provisions of the BLRA, SCE&G would respectfully show to the Commission the following:

I. INTRODUCTION

1. SCE&G is a corporation duly organized and existing under the laws of the State of South Carolina, with its principal offices at 220 Operation Way, Cayce, South Carolina 29033.

2. SCE&G is engaged in the business of generating, transmitting, and delivering electricity and providing electric service to the public for compensation. SCE&G owns and operates an integrated electric utility system that serves over 660,000 customers in 24 counties in central and southern South Carolina.

3. Corporate legal counsel for SCE&G in this proceeding are as follows:

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Matthew W. Gissendanner
South Carolina Electric & Gas Company
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(803) 217-8141
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Private legal counsel for SCE&G in this proceeding are as follows:

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All correspondence and any other matters relative to this proceeding should be addressed to these representatives.

II. PRIOR BLRA ORDERS

4. In Docket No. 2008-196-E, SCE&G sought approval of a Combined Application for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order for the Construction and Operation of a

Nuclear Facility in Jenkinsville, South Carolina for the Units. Pursuant to S.C. Code Ann. § 58-33-250(2), SCE&G provided the anticipated construction schedule and anticipated capital cost schedule for the Units.

5. Those schedules indicated that the Units could be constructed for a total cost to SCE&G of approximately \$4.5 billion in 2007 dollars.¹

6. Following a full hearing on the Combined Application, the Commission issued Order No. 2009-104(A), which approved the proposed construction schedule and capital cost schedule for the Units.

7. In Order No. 2010-12, dated January 22, 2010, the Commission approved SCE&G's request to update the construction schedule for the project and to update the capital cost schedule for the project to reflect changes in the forecasted timing of cash flow resulting from the updated construction schedule. The updated capital cost schedule did not alter the total estimated capital cost for the Units of approximately \$4.5 billion in 2007 dollars.

8. In Order No. 2011-345, the Commission approved the Company's request to update capital cost projections for the project. That request was filed in response to the decision by the Supreme Court of South Carolina in South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n, 388 S.C. 486, 697 S.E.2d 587 (2010), which disallowed costs that had not been itemized to specific capital cost items. In response, SCE&G removed its owner's contingency pool from the capital cost forecasts and sought Commission approval of specific costs that would otherwise have been accounted for

¹ Unless otherwise noted, all amounts reflect SCE&G's portion of the cost of the Units in 2007 dollars.

using the contingency allowance. Order No. 2011-345 established a total estimated capital cost for the Units of approximately \$4.3 billion in 2007 dollars.

III. CURRENT UPDATE REQUEST

9. Since the issuance of Order No. 2011-345, SCE&G has continued to revise and update the construction schedules and capital cost schedules for the Units as new information has emerged.

10. On February 29, 2012, SCE&G filed a Petition for Updates and Revisions to the Capital Cost Schedule and the Construction Schedule in Docket 2012-90-E based on information available at that time.

11. Since the time of that filing, major milestones in the progress of the project have been achieved.

12. On March 29, 2012, SCE&G and Westinghouse Electric Company and The Shaw Group, Inc. (together "WEC/Shaw") signed a preliminary agreement (the "Preliminary Agreement") providing for new substantial completion dates for the Units tied to the issuance date of the Combined Construction and Operating Licenses ("COL") which was anticipated in March of 2012. That Preliminary Agreement also resolved claims made by WEC/Shaw under the EPC Contract for additional charges related to the delay in the COL issuance, design changes made to the Units during licensing, unanticipated rock conditions at the site of the Unit 2 Nuclear Island and other matters.

13. On March 30, 2012, the United States Nuclear Regulatory Commission (the "NRC") issued the COL for the Units.

14. On that same day, the United States Army Corps of Engineers issued the Section 404 wetlands permit for the Units.

15. On April 19, 2012, SCE&G issued a Full Notice to Proceed to WEC/Shaw for construction of the Units.

16. These developments, all of which occurred since Docket 2012-90-E was established, have resulted in substantial revisions to the construction schedules and capital cost schedules filed in that docket.

17. To allow the South Carolina Office of Regulatory Staff ("ORS") and other parties a full opportunity to review these revisions, SCE&G, by letter dated May 8, 2012, withdrew the petition in Docket 2012-90-E and has filed new updated schedules in this docket. Doing so allows the Commission to establish a new schedule for the filing of testimony and the conduct of hearings on these matters and resets the six-month deadline for the issuance of an order.

18. Accordingly, this Petition is filed in place of the petition filed on February 29, 2012, in Docket 2012-90-E.

A. Updated Construction Schedule

19. The March 30, 2012 COL issuance date was approximately eight (8) months later than the issuance date on which the construction schedule and capital cost schedule approved in Order Nos. 2009-104(A), 2010-12, and 2011-345 were based.

20. To accommodate the resulting delay in the start of nuclear-safety related construction activities on-site and related issues (the "COL Delay"), SCE&G has agreed with WEC/Shaw that the substantial completion date for Unit 2 should be delayed to

March 15, 2017. SCE&G and WEC/Shaw have also agreed that the substantial completion date for Unit 3 should be accelerated to May 15, 2018, to provide for the closer synchronization of the construction schedules for the two Units. Such synchronization will create construction efficiencies that will partially offset the costs of the COL Delay.

21. **Exhibit 1** attached to this filing provides an updated construction milestone schedule for the project reflecting the aligning of all milestones to the current substantial completion dates and to the current construction and fabrication schedules.

B. Updated Cost Forecasts

i. Updated EPC Contract Costs

22. During the COL review process, the nuclear systems supplier for the Units, WEC, made certain design changes in the AP1000 Unit.

(a) One change related to a redesign of the shield building for the Units. This change (the "Shield Building Redesign") was undertaken to increase the shield building's resistance to aircraft impact.

(b) Another change related to an increase in the strength of the steel plates used in constructing certain structural modules that will be built off-site and installed in the Units using modular construction. This change (the "Module Redesign") was undertaken to strengthen the modules.

23. In addition, excavation and mapping of the rock conditions in the basement area for the Unit 2 Nuclear Island has discovered that in certain areas the bedrock is located deeper than test borings had indicated. This condition ("Unit 2 Rock

Conditions”) requires removal of additional material from the excavated area and the placement of additional concrete and other engineered materials in the resulting spaces. While it is not unusual to discover such conditions in a project of this kind, such conditions increase construction costs.

24. Furthermore, WEC/Shaw has determined that the COL Delay, as mitigated in part by the change in the substantial completion dates of the Units, will increase the cost of the project.

25. In 2011, WEC/Shaw asserted a claim that the costs associated with the Shield Building Redesign, the Module Redesign, the COL Delay and the Unit 2 Rock Conditions are costs that it is entitled to recover as additional charges under the Engineering, Procurement and Construction Agreement (“EPC Contract”) for the project. After extensive negotiation, SCE&G and WEC/Shaw have agreed to compromise and settle these claims for a \$137.5 million adjustment to the cost of the project under the EPC Contract.

26. In addition, in the Preliminary Agreement the parties agreed to reduce SCE&G’s exposure to future changes in escalation rates by fixing the escalation on the “Fixed with Indexed Adjustment Category” under the EPC Contract at a set escalation rate going forward for the life of the project. Costs in this cost category were previously escalated based on the Handy-Whitman Indices. The Handy Whitman Indices will continue to be used to forecast non-firm (Target) cost categories, *i.e.*, Actual Craft Wages, Non-Labor Costs and Time & Materials.

ii. Other Change Orders

27. **Cyber Security** – In late 2011, an agreement was reached between SCE&G and WEC/Shaw on a phased approach for ascertaining the costs that will be associated with strengthening the Units' defenses against cyber attacks ("Cyber Security"). The Phase I scope of the Cyber Security plan will involve review of the specific equipment and software that will be used in the Units to identify potential vulnerabilities to cyber attack and to devise a scope of work to protect against those vulnerabilities. Phase I of the Cyber Security work will be undertaken for a price of \$914,422 which is principally a firm price with certain non-firm time and materials components. Phase II will involve the actual software programming and other work necessary to overcome the vulnerabilities identified in Phase I. The cost of Phase II is estimated to be approximately \$4.95 million. Other phases of work may be required but are not known at this time.

28. **Waste Water Piping** – On December 9, 2011, WEC/Shaw presented SCE&G with an estimate for a detailed scope of work and associated costs for a revision to the design of the waste water discharge piping for gravity drainage to the Waste Water System Discharge Piping, as specified in SCE&G's COL application. WEC/Shaw has determined that the cost of this work will be \$8,250.

29. **Health Care Costs** – During the last quarter of 2011, WEC/Shaw initiated Change Order No. 12 requesting reimbursement for Shaw's increased costs as a result of a change in law related to portions of the Health Care and Education Reconciliation Act of 2010 ("Health Care Act"). SCE&G approved the change order in December 2011.

The total costs associated with this action are \$135,573 and are spread throughout the remaining period of the project. At this time, WEC has not quantified any additional costs related to the Health Care Act. Additional change orders may be generated by WEC or by Shaw to cover future cost impacts associated with the Health Care Act.

iii. Owners Costs

30. During 2011 and 2012, SCE&G's leadership conducted an intensive review of the staffing required to effectively operate the Units. This work has resulted in revised staffing plans and revised Owners costs estimates to replace the prior estimates of Owners costs.

31. As a result of this review, SCE&G has updated the project hiring plan for New Nuclear Deployment ("NND") Construction Oversight and Operational Readiness staffs to reflect the additional skills, training and experience that will be required to staff the Units in a way that will ensure that they can be operated safely and efficiently when construction is complete.

32. SCE&G has also increased construction oversight staffing to provide for additional quality assurance and quality control ("QA/QC") resources to oversee the QA/QC programs of its contractors and suppliers. Such oversight is the regulatory responsibility of SCE&G as owner of the Units. Oversight of QA/QC for the project has been identified as a key goal for NND during the construction process.

33. In addition, operational staffing of the Units and other costs have increased due to rulemakings that have been issued or are anticipated by the NRC as a result of the safety reviews undertaken in light of the recent Fukushima earthquake and tsunami.

34. NND staffing plans and other Owners Cost estimates have also been revised to reflect the impacts of the COL Delay and the changes in the substantial completion dates of the Units.

35. The Owners Cost estimates further include the current estimates of the cost of training facilities and other facilities, information technology ("IT") systems and the other infrastructure and equipment that will support the Units and their personnel.

36. This updating has resulted in an increase in the forecast for Owners Costs for the Units of approximately \$131.6 million.

iv. Transmission Costs

37. In light of the foregoing, SCE&G has also re-forecasted transmission costs associated with the Units based on additional design and engineering work, updated evaluations of power flows, and more complete information about right-of-way and property requirements. In this regard:

(a) SCE&G has determined that it is preferable to construct a new Saluda River 230/115 kilovolt ("kV") Substation as opposed to installing additional autobanks at the Lake Murray 230/115 kV Substation and the Denny Terrace 230/115 kV Substation. Accommodating power flows from the Units under this new configuration will require upgrading the 115 kV line between the Saluda River substation and the Lyles substation and other improvements.

(b) SCE&G has decided to move from overhead to underground a section of the existing Parr-VCSN Safeguard 115 kV line where that line will be crossed by multiple new lines being built to support the Units. Undergrounding

this segment of the line will enhance the safety and reliability of power supplies to the Units and will represent a new cost to the project.

(c) Transmission line conductor upgrades to accommodate power from the new units will require terminal and bus upgrades at the Canadys, Summerville and Saluda Hydro Substations.

(d) As a result of detail design and routing for the 230 kV transmission lines terminating into the new switchyard, the Parr-Midway 115 kV Line has been lowered to meet required minimum National Electric Safety Code crossing clearances.

The cost increases associated with these and other changes have been netted against other budgetary items where costs to the project have been reduced. As a result of these and other changes and upgrades, transmission cost forecasts have increased by approximately \$7.9 million.

C. Revised Capital Cost Schedules

38. **Exhibit 2** attached to this filing provides the Commission with an updated capital cost schedule for the Units.

39. As set forth in **Exhibit 2**, the updated capital cost schedule in 2007 dollars is approximately \$4.6 billion, which reflects an increase of approximately \$283.0 million in the costs approved in Order No. 2011-345.

40. For ease of reference, **Exhibit 3** provides information showing the variation between the capital cost schedule approved by the Commission in Order No. 2011-345 and the capital cost schedule contained in **Exhibit 2**.

41. The updated capital cost schedule set forth in **Exhibit 2** also reflects the most current inflation indices applied as mandated by the Commission in Order No. 2009-104(A) and the change in escalation index for the Firm with Indexed Adjustment category under the EPC Contract. The updated capital cost schedule in future dollars, including Allowance for Funds Used During Construction, is approximately \$5.8 billion which is approximately \$25 million less than the similar forecast of costs and escalation reflected in Order No. 2011-345.

42. **Exhibit 4** provides a reconciliation of the changes in forecasted costs shown on **Exhibit 2** to those approved in Order No. 2011-345. Also shown is a comparison of the escalation indices in effect under Order No. 2011-345 to those currently in effect.

D. Conclusion as to Updated Construction and Capital Cost Schedules

43. Pursuant to S.C. Code Ann. § 58-33-270(E), when a utility petitions for adjustments in the construction schedule or capital cost schedule for a project being constructed under the BLRA, the Commission “shall grant the relief requested if, after a hearing, the commission finds: (1) as to the changes in the schedules, estimates, findings, or conditions, that the evidence of record justifies a finding that the changes are not the result of imprudence on the part of the utility”

44. The construction schedule and capital costs reflected in **Exhibit 1** and **Exhibit 2** are the result of normal and prudent revisions, changes and refinements in the construction program for the project.

45. The capital cost schedule contained in **Exhibit 2** contains no contingencies or other provisions for the additional capital costs that may be identified to specific items of cost in the future as construction of the Units proceeds. For that reason, SCE&G reserves the right to update this schedule during the pendency of this proceeding as cost forecasts are updated and supplemented.

46. SCE&G will continue to monitor and evaluate the construction schedule and schedule of capital costs. To the extent future revisions or updating of **Exhibit 1** or **Exhibit 2** or other revisions under S.C. Code Ann. § 58-33-270(E) are required, SCE&G will propose such changes for review by the Commission, either through updating **Exhibit 1** and **Exhibit 2** during this proceeding or through future filings and proceedings.

IV. PRAYER FOR RELIEF

WHEREFORE, South Carolina Electric & Gas Company respectfully requests that the Commission set the current matter for hearing and thereafter, pursuant to S.C. Code Ann. § 58-33-270(E),

- A. Approve the updated construction schedule attached as **Exhibit 1**, and the updated capital cost schedule attached as **Exhibit 2**, as they may be amended during the pendency of this proceeding, to be the operative schedules for construction of the Units under S.C. Code Ann. § 58-33-275(A).

B. Grant other relief as may be appropriate.

Respectfully submitted,



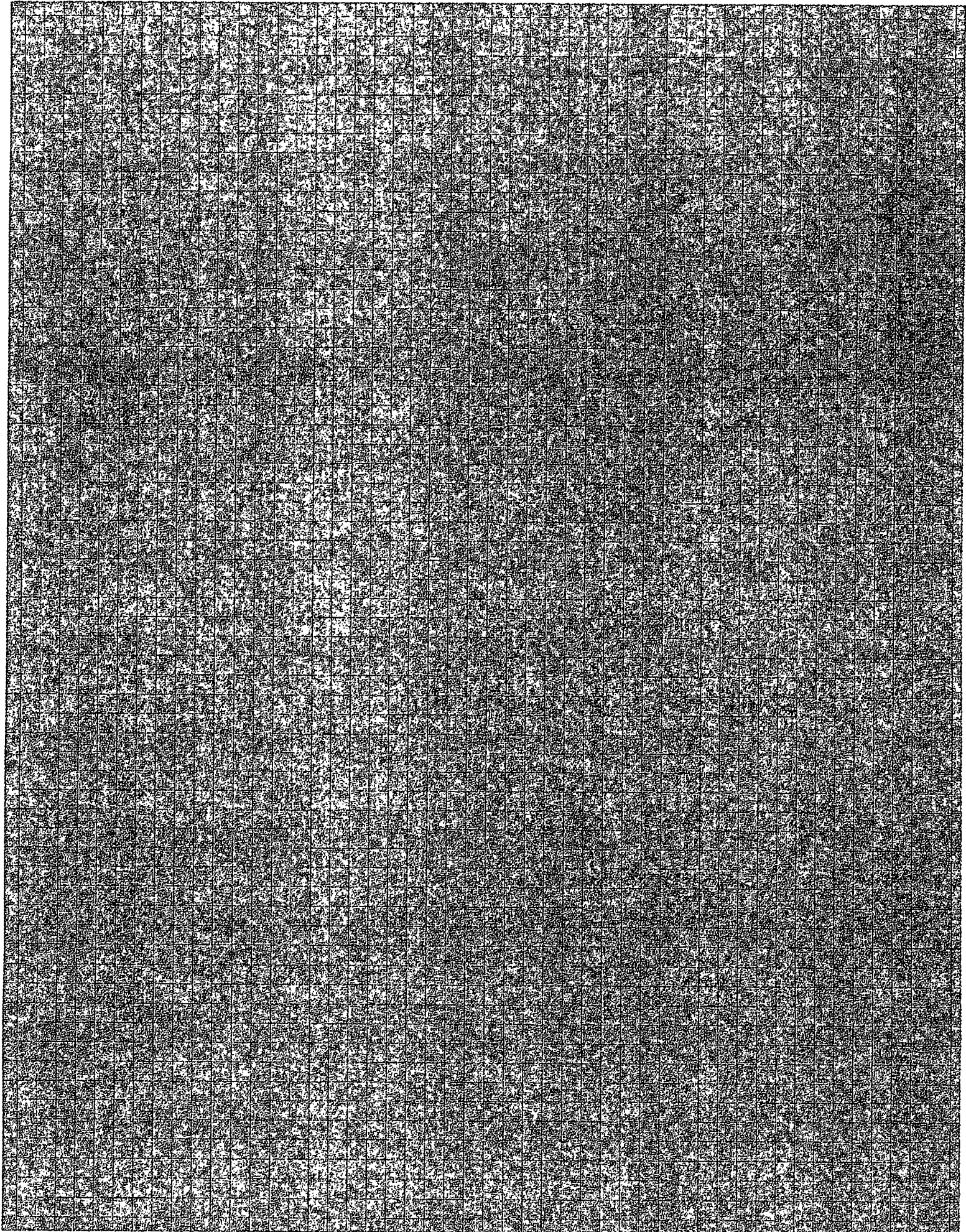
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Attorneys for South Carolina Electric & Gas Company

Cayce, South Carolina

Date: May 15, 2012



BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2012-203-E

In Re: Petition of South Carolina Electric & Gas Company for Updates and Revisions to Schedules Related to the Construction of a Nuclear Base Load Generation Facility at Jenkinsville, South Carolina	))))))	PETITION TO INTERVENE BY SIERRA CLUB

The Sierra Club, on behalf of its members who will be adversely affected by the approval of the subject Petition, hereby petitions the Commission pursuant to R. 103-825 of the Commission's Rules and Regulations to intervene and be made a party of record in the above-referenced proceeding. In support of this Petition, Sierra Club would respectfully show:

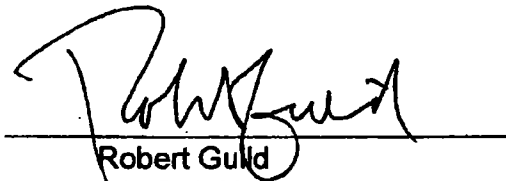
1. The Sierra Club is the oldest and largest non-profit grassroots environmental organization in the world with some 750,000 members, 65 Chapters, over 400 local groups. The South Carolina Chapter has nine local groups with more than 5,000 members across the state. The Club's mission is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. The Club and its members actively promote safe energy solutions

including energy efficiency and renewable energy resources to combat the climate crisis and to protect human health and the natural environment. The organization has been actively involved in a variety of issues involving nuclear power production and nuclear waste disposal in South Carolina. The South Carolina Chapter of the Club has offices and meeting space at 1314 Lincoln Street #211, Columbia, South Carolina 29301. Members of the Sierra Club are customers of SCE&G who live, work, recreate and use natural resources near the existing Summer nuclear plant and the site of the proposed Summer reactors.

2. Members of the Sierra Club would be harmed by the approval of the subject Petition because of unwarranted increases in their electric rates, reduced reliability of their electric service, the displacement of environmentally superior energy efficiency and renewable energy production alternatives, the risk to their health and safety from routine and accidental releases of radiation, and harm to their use and enjoyment of natural resources which will be adversely affected by the approval of this Petition, the subsequent costs associated with this project, and the construction and operation of the proposed nuclear facility.

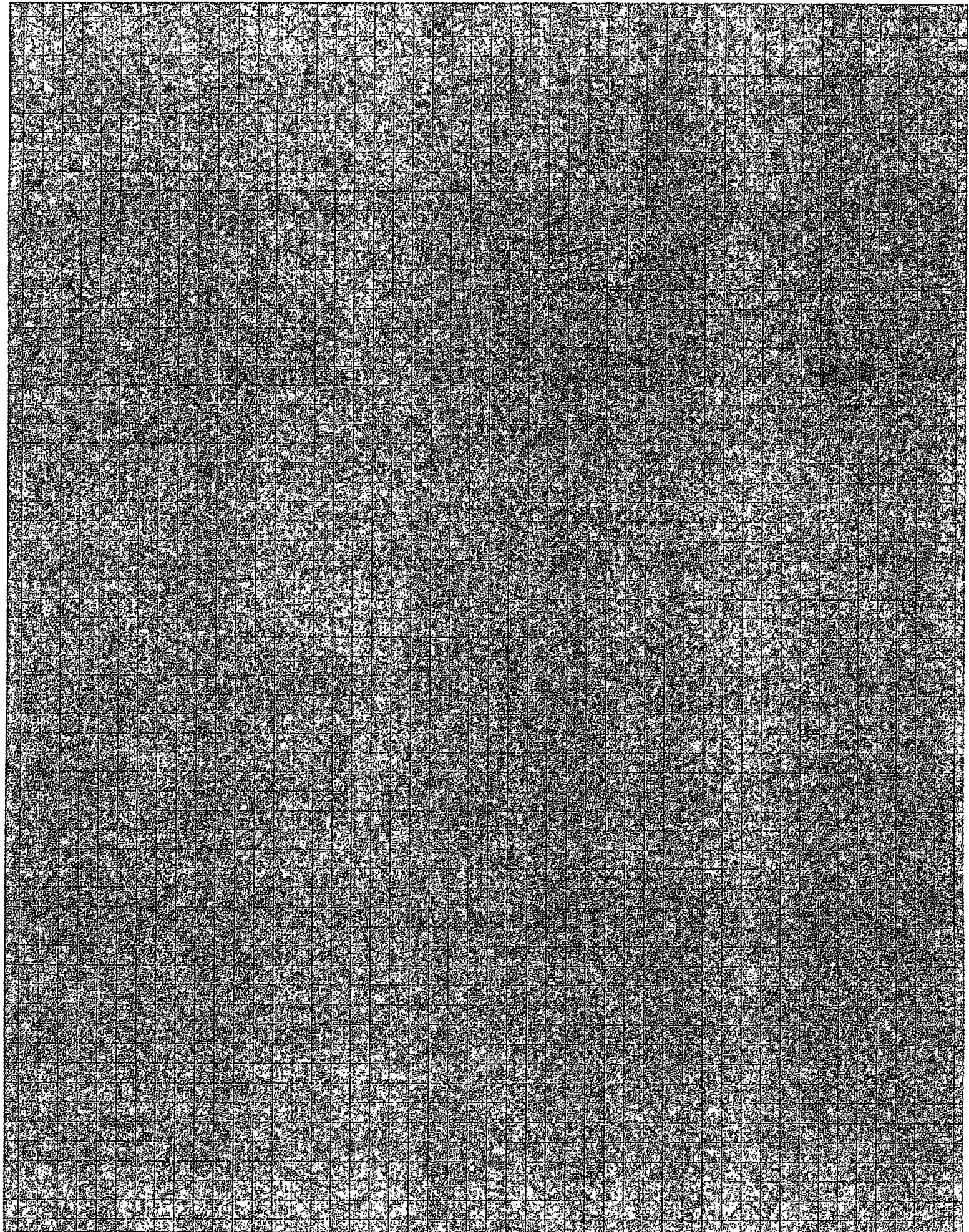
3. Sierra Club is informed and believes that the construction schedule delays and the capital cost schedule increases proposed by South Carolina Electric & Gas Company are material and adverse deviations from the approved schedules which the utility failed to anticipate or avoid; and which are, therefore, the result of imprudence on the part of the utility, considering the information available at the time the utility could have acted to avoid the deviation or minimize its effect, all contrary to S.C. Code Sections 58-33-270(E) and 58-33-275(E).

WHEREFORE: For the foregoing reasons, Sierra Club, on behalf of its members who will be adversely affected by the approval of the subject Petition, hereby petitions the Commission pursuant to R. 103-825 of the Commission's Rules and Regulations to intervene and be made a party of record in the above-referenced proceeding; to permit full discovery and disclosure of the information bearing on the deviations from the approved construction and capitol cost schedules; and to determine, on the basis of such information, that the subject Petition should be denied due to the imprudence of the utility, South Carolina Electric & Gas Company.

A handwritten signature in black ink, appearing to read "Robert Guld", is written over a horizontal line.

Robert Guld
344 Pall Mall
Columbia, South Carolina 29201
(803) 252 1419
ATTORNEY FOR SIERRA CLUB

May 23, 2012



STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2012-203-E

IN THE MATTER OF:)

Petition of South Carolina Electric & Gas)
Company for Updates and Revisions to)
Schedules Related to the Construction of a)
Nuclear Base Load Generation Facility at)
Jenkinsville, South Carolina)

PETITION TO INTERVENE

The South Carolina Energy Users Committee ("SCEUC") hereby petitions the South Carolina Public Service Commission ("Commission") pursuant to R.103-825 of the Commission's rules and regulations to intervene and be made a party of record in the above-captioned docket. In support of this Petition, SCEUC would allege as follows:

21
1. That on May 15, 2012, South Carolina Electric & Gas ("SCE&G") filed a petition with the Commission, pursuant to S.C. Code Ann. §58-33-270(1), seeking an order approving an updated construction schedule and capital cost schedule for the Units. The updated construction schedule seeks to revise the construction plan for the Units based on the issuance of the combined operating license for the Units by the Nuclear Regulatory Commission in early 2012, not mid-2011 as originally anticipated. The Petition also seeks to incorporate approximately \$283 million in capital costs that have been incurred or have been identified since the issuance of Order No. 2011-345. This petition replaced a petition filed on February 29, 2012 which SE&G withdrew by letter dated May 8, 2012.

2. That SCEUC is an association organized in the State of South Carolina, consisting of large industrial consumers of energy which are engaged in various manufacturing enterprises throughout the State.

3. That a number of members of SCEUC purchase and consume substantial amounts of electricity from SCE&G.

4. That SCEUC and its members have a direct and material interest in the issues to be addressed and resolved by the Commission in this docket and the interests of its members are not adequately represented by the current parties to this proceeding.

5. That given the state of the record at this stage of the proceedings, SCEUC lacks sufficient information to fully develop and state its position in this proceeding at this time.

6. That granting SCEUC's request to be made a party of record in this proceeding is in the public interest, is consistent with the policies of the Commission in encouraging maximum public participation in issues before it, and should be allowed so that a full and complete record addressing its views and concerns can be developed.

7. That Petitioner is represented by counsel in this proceeding as follows:

Scott Elliott, Esquire
Elliott & Elliott, P.A.
1508 Lady Street
Columbia, South Carolina 29201
Telephone: 803-771-0555
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WHEREFORE, Petitioner prays for the following relief:

- a. That this Petition to Intervene be accepted and that Petitioner be made a party of record;

- b. That Petitioner be allowed to participate fully in this proceeding and take such positions as it deems advisable; and
- c. For such other and further relief as is just and proper.

P. 3

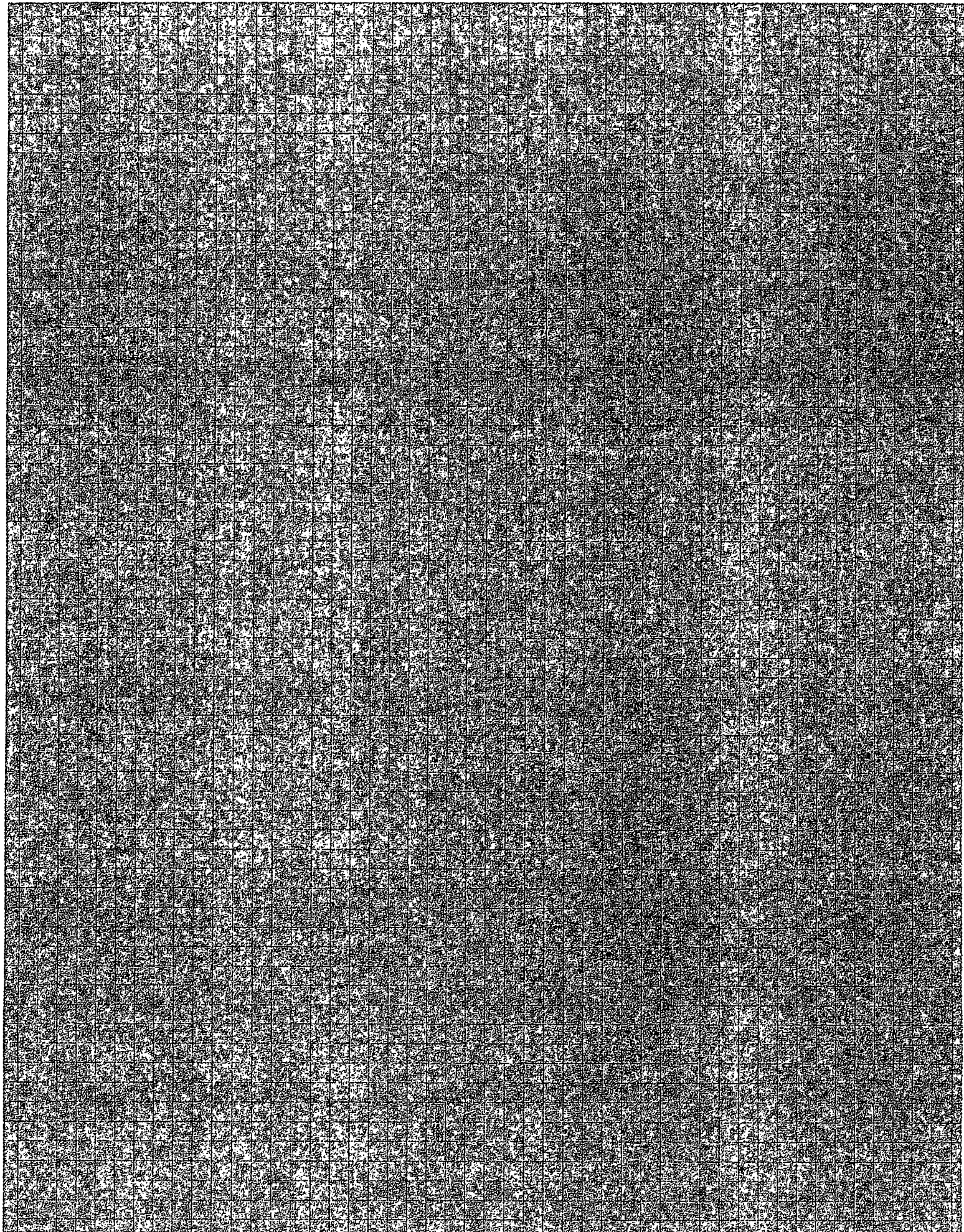


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June 1, 2012



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October 26, 2012

VIA E-FILING

Jocelyn Boyd, Esquire
Chief Clerk of the Commission
SC Public Service Commission
P. O. Drawer 11649
Columbia, SC 29211

RE: Petition of South Carolina Electric & Gas Company for Updates and Revisions to
Schedules Related to the Construction of a Nuclear Base Load Generation Facility at
Jenkinsville, South Carolina
Docket No. 2012-203-E

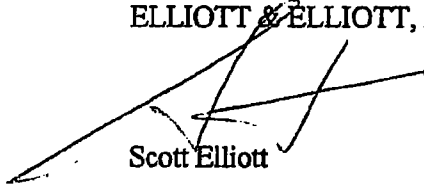
Dear Ms. Boyd:

Enclosed please find for filing a proposed Order Denying Petition for Updates and Revisions to
Schedules on behalf of the South Carolina Energy Users Committee ("SCEUC") in the above-
captioned matter. By copy of this letter, I am serving all parties of record.

If you have questions, please do not hesitate to contact me.

Sincerely,

ELLIOTT & ELLIOTT, P.A.



Scott Elliott

SE/mlw

Enclosure

cc: All parties of record (w/encl.)

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2012-203-E - ORDER NO. 2012-
October ____, 2012

IN RE: Petition of South Carolina Electric & Gas Company for Updates and Revisions to Schedules Related to the Construction of a Nuclear Base Load Generation Facility at Jenkinsville, South Carolina	)	ORDER DENYING PETITION FOR UPDATES AND REVISIONS TO SCHEDULES

I. INTRODUCTION

The matter comes before the Public Service Commission of South Carolina (the "Commission") on the petition of South Carolina Electric & Gas Company ("SCE&G" or the "Company") for an order approving an updated capital costs schedule for the construction of two 1,117 net megawatt nuclear power units (the "Units") to be located at the V.C. Summer Nuclear Station near Jenkinsville, South Carolina. SCE&G filed the Petition in this docket (the "Petition") on May 15, 2012, pursuant to S.C. Code Ann. §58-33-270 (E). Under that provision of the Base Load Review Act (the "BLRA"), a utility "may petition the Commission . . . for an order modifying any of the schedules, estimates, findings, class allocation factors, rate designs, or conditions that form part of any base load review order." S.C. Code Ann. § 58-33-270(E). However, the BLRA provides certain protections for SCE&G ratepayers: Thus, the Commission may:

disallow the additional capital costs that result from the deviation, but only to the extent that the failure by the utility to anticipate or avoid the deviation, or to minimize the resulting expense, was imprudent considering the information available at the time that the utility could have acted to avoid the deviation or

minimize its effect. S.C. Code Ann § 58-33-275(E).

In Order No. 2009-104(A), dated March 2, 2009, the Commission initially approved a capital costs schedule for the Units totaling \$4.5 billion in 2007 dollars. The South Carolina Supreme Court decision in South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n, 697 S.E. 2d at 592 reversed certain provisions of Order No. 2009-104(A) not relevant here.

In Order No. 2010-12, dated January 22, 2010, the Commission approved an updated construction schedule for the project and an updated capital costs schedule which reflected that updated construction schedule. The capital costs schedule approved in Order No. 2010-12 however, did not alter the total estimated capital cost for the Units of \$4.5 billion in 2007 dollars.

In Order No. 2011-345, dated May 16, 2011, the Commission approved an updated capital cost schedule for the project and approved an additional \$174 million in capital costs.

In the present proceeding, SC&G seeks approval of an updated capital costs schedule in the amount of \$283 million for the construction of two 1,117 net megawatt nuclear power units to be located at the V.C. Summer Nuclear Station near Jenkinsville, South Carolina.

As required by S.C. Code Ann. §58-33-270 (E), SCE&G provided notice of the filing in this docket to the South Carolina Office of Regulatory Staff ("ORS"). By letter dated May 29, 2012, the Commission Clerk's Office instructed the Company to publish by July 15, 2012, a Notice of Filing and Hearing ("Notice") in newspapers and to provide a copy of the Notice to these customers by U.S. mail or by electronic mail to customers who have agreed to receive the Notice by electronic mail. The Company requested an extension to publish the Notice and filed an affidavit on July 13, 2012 demonstrating that the Notice was duly published in accordance

with the instructions of the Clerk's Office and certified that a copy of the Notice was furnished to each affected customer.

Timely Petitions to Intervene were received from the South Carolina Energy Users Association ("SCEUC"), Sierra Club and Pamela Greenlaw, which were unopposed. The Petition to Intervene filed by Mr. Joseph Wojcicki was opposed and his Petition dismissed by the Commission. The ORS is automatically a party pursuant to S.C. Code Ann. §58-4-10.

The Commission convened a public hearing on this matter on October 2, 2012, with the Honorable David A. Wright, Chairman, presiding. SCE&G was represented by K. Chad Burgess, Esquire, Matthew W. Gissendanner, Esquire and Belton T. Zeigler, Esquire. The ORS was represented by Shannon Hudson, Esquire, and Courtney D. Edwards, Esquire. SCEUC was represented by Scott Elliott, Esquire. The Sierra Club was represented by Robert Guild, Esquire. Pamela Greenlaw appeared *pro se*.

In support of the Petition, the Company presented the testimony of Kevin B. Marsh, Chairman and Chief Executive Officer of SCANA Corporation and SCE&G; Stephen A. Byrne, Chief Operating Officer and Executive Vice President for Generation and , David A. Lavigne, General Manager of Operational Readiness for New Nuclear Deployment for SCE&G, Hubert C. Young, III, Manager of Transmission Planning and Carlette L. Walker, Vice President for Nuclear Finance Administration and the rebuttal testimony of Joseph M. Lynch, Manager of Resource Plant for SCE&G. ORS presented the direct testimony of Allyn H. Powell and Doug C. Jones, P.E. The Sierra Club presented Dr. Mark Cooper, Director of Energy and Director of Research at Consumer Federation of America. SCEUC presented no witnesses at the hearing.

II. DISCUSSION

The Commission may exercise only that authority granted it under the BLRA. South

Carolina Electric & Gas Company v. South Carolina Public Service Commission, supra; Nucor Steel v. South Carolina Public Service Commission, 310 SC 539, 426 SE 2nd 319 (1992).

The Base Load Review Act

The BLRA provides that, as long as a nuclear plant is constructed in accordance with the approved schedules, estimates and projections, as adjusted by the inflation indices, a utility must be allowed to recover its capital costs related to plant through revised rate filings §58-33-275(C). The purpose of the BLRA,

is to provide for the recovery of the prudently incurred costs associated with new base load plants, as defined in Section 58-33-220 of Article 4, when constructed by investor-owned electrical utilities, while at the same time protecting customers of investor-owned electrical utilities from responsibility for imprudent financial obligations or costs. Base Load Review Act Section 1(A).

To balance the interests of the utility and the rate payer, the General Assembly designed a specific and detailed statutory blueprint for establishing prudent costs to be recovered through revised rate filings. The Commission's authority to issue a base load review order is prescribed by the express terms of the BLRA. A base load review order issued pursuant to the BLRA,

means an order issued by the commission pursuant to Section 58-33-270 establishing that if a plant is constructed in accordance with an approved construction schedule, approved capital costs estimates, and approved projections of in-service expenses, as defined herein, the plant is considered to be used and useful for utility purposes such that its capital costs are prudent utility costs and are properly included in rates. S.C. Code Ann. Section 58-33-220(4).

If a utility establishes that its nuclear plant is constructed in accordance with (1) an approved construction schedule, (2) approved capital costs estimates, and (3) approved projections of in-service expenses, the nuclear plant is considered to be used and useful for utility

purposes and are properly included in rates. §58-33-220(4). The Act defines "capital costs" as follows:

(5) 'Capital costs' or 'plant capital costs' means costs associated with the design, siting, selection, acquisition, licensing, construction, testing, and placing into service of a base load plant, and capital costs incurred to expand or upgrade the transmission grid in order to connect the plant to the transmission grid and includes costs that may be properly considered capital costs associated with a plant under generally accepted principles of regulatory or financial accounting, and specifically includes AFUDC associated with a plant and capital costs associated with facilities or investments for the transportation, delivery, storage, and handling of fuel. S.C. Code Ann. Section 58-33-220(5).

The BLRA expressly sets out the factual showing necessary for a base load review order. S.C. Code Ann. §58-33-250 provides (in its pertinent part):

The application for a base load review order under this article shall include:

- (1) information showing the **anticipated** construction schedule for the plant; [Emphasis added]
- (2) information showing the **anticipated** components of capital costs and the anticipated schedule for incurring them; [Emphasis added]

The BLRA provides that as circumstances warrant, a utility may petition the Commission for an order modifying its schedules in the Base Load Review Order. However, the proposed changes may not be the result of imprudence on the part of the utility. Sections 58-33-270(E), 58-33-275(E). The definition of the term imprudence as it applies to the instant docket can be found in Section 58-33-275(E) which reads:

In cases where a party proves by a preponderance of the evidence that there has been a material and adverse deviation from the approved schedules, estimates, and projections set forth in Section 58-33-270(B)(1) and 58-33-270(B)(2), as adjusted by the inflation indices set forth in Section 58-33-270(B)(5), the commission may disallow the additional capital costs that result from the deviation, but only to the extent that the failure by the utility to anticipate or avoid the deviation, or to minimize the resulting expense, was imprudent considering the information available at the time that the utility could have acted to avoid the deviation or minimize its effect.

Therefore, this Commission may disallow additional capital costs which result from SCE&G's failure to anticipate or avoid the additional costs which it seeks here. (See also Section 58-33-280(K) which provides that where a plant is abandoned after a BLRA order, the utility's recovery of capital costs may be disallowed to the extent that the failure by the utility to anticipate or avoid the allegedly imprudent costs was imprudent considering the information available at the time the utility could have acted to avoid or minimize the costs.)

The BLRA provides the utility with a novel way to recover the costs of nuclear construction by permitting advanced cost recovery. As long as the plant is constructed within approved schedules, estimates and projections set forth in Sections 58-33-270(B)(1) and 58-33-270(B)(2), the utility must be allowed to recover its capital costs related to the plant through revised rate filings. However, the BLRA does not give a utility the authority to recover additional costs which could have been anticipated at the time of the BLRA application, and thus the provisions of Section 58-33-270(E) do not permit frequent or even annual applications to amend an order issued under the BLRA for capital costs overlooked by the utility in its BLRA application.

STATEMENT OF THE FACTS

SCE&G has petitioned the Commission to approve an additional \$283 million in capital costs to be included to the utility's BLRA order. The request includes costs which SCE&G has incurred for which it seeks approval as well as costs that it now anticipates it will incur in the future.

First, SCE&G seeks approval of Change Order 16 which formalizes an agreement entered into among SCE&G, Santee Cooper, and Westinghouse that resolved claims by Westinghouse/Shaw for additional costs associated with four matters:

1. The shield building for the AP 1000 unit as it had been redesigned to increase its resistance to aircraft impacts;
2. Rescheduling the construction plan for the Units to take into account the approximately nine month delay in the issuance of the COL;
3. The structural modules for the project, as redesigned, using higher strength steel than was originally specified, among other changes; and
4. Responding to unanticipated rock conditions at the foundation of Unit 2. (Byrne prefled testimony at p. 20, ll. 1-14).

The settlement costs total \$137.5 million which SCE&G seeks to recover in rates in this docket.

At the time of SCE&G's 2008 BLRA application, the Westinghouse AP 1000 nuclear generators had not been approved by the Nuclear Regulatory Commission ("NRC"). In 2008, Westinghouse had submitted 15 revised designs to the NRC for approval and had been informed that the NRC would require a 16th revision. The NRC was reviewing the ability of the AP 1000 shield building to withstand the impact of an airplane crash. SCE&G represented to the Commission in 2008 that the NRC design approval was expected by July 2011 at which time SCE&G would be granted its Combined Operating License ("COL") (Tr. at p. 326, l. 15- p. 329, l. 22). Mr. Byrne testified that SCE&G addressed the risk that the NRC would refuse to approve the AP1000 design that SCE&G submitted to the Commission in its 2008 BLRA application. SCE&G included additional amounts in its cost estimates to pay for increased costs associated with future improvements to the AP1000 design ultimately required by the NRC (Tr. at p. 330, ll. 19-23). In support of its Application under the BLRA in 2008, SCE&G had represented to the

Commission that it had adequate contractual safeguards to protect it and its ratepayers in the case of delays in approval of the AP 1000 designs. Moreover, Mr. Byrne testified in the 2008 docket that SCE&G had negotiated contractual provisions in its EPC contract subjecting Westinghouse to certain penalties in the event the COL was delayed due to Westinghouse's inability to have its AP 1000 design approved timely (Tr. at p. 330, l. 24 – p. 331, l. 21). The NRC did not approve final plans for the AP 1000 units until December of 2011. SCE&G received its COL on March 30, 2012, approximately nine months after approval was expected. (Byrne prefiled testimony p. 26, ll. 17-21; Tr. at p. 332, ll. 22-24).

The first three elements of Change Order 16 set out above relate to the delay in the approval of the COL. One of the reasons given by SCE&G for the delay in the issuance of the COL was the delay in Westinghouse/Shaw obtaining approval of its final plans for the AP 1000. (Byrne prefiled testimony p. 27, ll. 8-12.) Westinghouse submitted a total of nineteen revisions before it received final approval of its nuclear reactors. At the time of the utility's Application under the BLRA, Westinghouse/Shaw had submitted fifteen revisions and had drafted DCD Revision No. 16. (Tr. at p. 326, l. 25 – p. 328, l. 21). The final design for the AP 1000 was submitted to the NRC as DCD Revision No. 19. The delay in approval of DCD Revision No. 19 was Westinghouse's inability to satisfy the NRC that the shield buildings would be sufficiently hardened to withstand aircraft impacts. (Byrne prefiled testimony p. 20, ll. 8-9; p. 29, ll. 7-13). Mr. Byrne acknowledges that at the time the EPC contract was negotiated it was anticipated that the NRC would require additional measures to be incorporated into the AP 1000 design to strengthen its resistance to aircraft impacts. However, SCE&G failed to anticipate the actual cost of the final AP 1000 design and the NRC requirements for hardening the shield buildings involved more cost than SCE&G presented to the Commission for approval in its 2008 BLRA

application. Moreover, SCE&G failed to negotiate adequate contractual safeguards in its EPC contract with Westinghouse/Shaw to protect it from damages due to the delay and the additional costs associated with the final design. (Byrne prefiled testimony p. 23, ll. 4-13). Mr. Byrne testified that the parties' EPC contract provided for change orders where cost increases are due to "uncontrollable circumstances." Westinghouse construed this term broadly enough to have excused it from liability for the delay costs and the additional costs associated with hardening of the shield building. (Byrne prefiled testimony p. 25, ll. 3-18). SCE&G chose not to contest Westinghouse's position but chose instead to settle Westinghouse's claim for \$137.5 million.

Mr. Byrne accedes that the principal reason for the delay was not the approval of the Westinghouse AP 1000 design but rather SCE&G's failure to obtain its wetlands permits under the National Environmental Policy Act ("NEPA"). Under federal law, the COL could not be issued for the AP 1000 units until the Company proved to the Corps of Engineers and the Environmental Protection Agency ("EPA") that the project complied with Clean Water Act standards. Here, the water quality certification was not issued for the nuclear project until December 16, 2011, about the same time as DCD Revision No. 19 was approved by the NRC. (Byrne prefiled testimony p. 29, l. 14 - p. 30, l. 10). The delay in receiving the water quality certification arose from the fact that instead of locating the necessary transmission lines for this project in existing right-of-ways, SCE&G chose instead to attempt route the transmission lines in new corridors. Employing a macro-corridor approach to transmission siting, SCE&G sited its transmission lines in county-by-county corridors and quantified the environmental impacts of placing the lines in these corridors. The specific location of the lines was left until detailed engineering and siting studies were completed later in the process. (Byrne prefiled testimony p. 30, l. 11 - p. 31, l. 4). There was considerable public concern and comment about the proposed

transmission siting which SCE&G anticipated at the time it filed its BLRA application (Tr. at p. 345 , ll. 5-10). SCE&G fell behind with respect to its schedule and several state and federal agencies informed SCE&G that it must site its transmission lines using existing transmission corridors (Young prefiled direct testimony at p. 10, l. 18 – p. 11, l. 1). The macro corridor approach does not identify the specific wetlands issues to be addressed by the transmission siting (Tr. at page 343, ll. 9-18). Refusing to accept the less certain macro corridor approach, the EPA and Army Corps of Engineers took the position that specific transmission line routes had to be identified and the environmental impacts of the specific routes had to be assessed before the environmental review could proceed. (Byrne prefiled testimony p. 32, ll. 10-17). In response, SCE&G decided to route its new transmission lines in existing corridors (with a single six mile exception). This approach allowed the routes to be established quickly and the environmental impacts from them to be assessed on an expedited basis. Mr. Byrne testified that it would have been prudent for SCE&G to have initially determined to use its existing easements and rights-of-way for the transmission lines. (Tr. at p. 348, ll. 14-22). SCE&G had determined to use existing right-of-ways for siting its transmission lines by April 2011 and the wetlands certification were approved eight months later in December 2011. (Tr. at p. 344, ll. 10-17). On this record, had SCE&G determined from the outset to use existing transmission lines, the water quality certification would not have been delayed past the July 2011 milestone.

The delays acknowledged by SCE&G in this docket give rise to a substantial portion of the settlement among the parties in Change Order 16. After negotiations, SCE&G and the remaining parties settled Westinghouse/Shaw's claim for an amount of \$137.5 million. The utility is not before the Commission seeking approval of the Settlement Agreement with Westinghouse. The matter has been settled and SCE&G owes Westinghouse \$137.5 million.

The question remains as to whether the Commission will authorize the additional \$137.5 million to be placed in rates pursuant to the BLRA.

On this record, the reasonableness of the settlement is far from clear. Mr. Byrne does describe a process whereby SCE&G negotiated settlement from \$213.6 million to \$137.5 million. There is no other evidence of record as to the reasons for the settlement. However, based on the testimony of record, SCE&G was bargaining from a weakened position and agreed to settle its claim against Westinghouse by paying Westinghouse \$137.5 million.

The fourth matter of the Change Order 16 involved the cost of addressing rock conditions at the foundation of Unit 2. The Company provided very little information about this aspect of the change order except to say that because the condition was below the surface, the Company could not have been expected to have anticipated encountering the rock conditions. However, implicit in the record is the fact that unexpected sub-surface conditions are encountered frequently in construction and there is no real explanation of record as to why potential for sub-surface rock conditions and the costs to address them were not anticipated.

SCE&G seeks to include an additional \$131.6 million in owner's costs in its Base Load Review Order in this petition. First, it should be noted that the Commission by Order 2011-345 issued May 16, 2011, authorized SCE&G to include \$145 million in owner's costs. Just nine months later, SCE&G presents itself before this Commission seeking an additional \$131.6 million in owner's costs.

The additional owners' costs can be found at Chart B found in Ms. Walker's testimony at p. 12, l. 6. These costs are generally for increased IT infrastructure including licenses, hardware, software and implementation costs, additional labor or employment costs and additional facilities costs.

Ms. Walker testified that SCE&G created the owner's cost estimates in its 2008 BLRA Application while it was evaluating nuclear generation options and negotiating the terms of the EPC contract and SCE&G did not allow itself adequate time to determine its actual owner's costs prior to filing its BLRA application. Instead, SCE&G submitted only an estimate of its owner's costs in 2008 in its BLRA application and evidence (Tr. Docket No. 2010-376-E at p. 295, l. 21-p. 206; l. 8; p. 297, ll. 6-15; p. 304; ll.16-22). Ms. Walker acknowledges that SCE&G sought and obtained an additional \$145 million in owner's costs in Docket 2010-376-E. Ms. Walker testifies that the owner's cost figures approved in that docket were based on a "detailed staffing plan, the project budget and a cost center by cost center review of the cost of the project that had been compiled during the period 2008 through 2010. (Walker prefled direct testimony at p. 8, l. 19 through p. 9, l. 7). According to Ms. Walker, the request of an additional \$145 million in owner's costs in Docket No. 2010-376-E was required because SCE&G had lost the use of the contingency fund approved in Order No. 2009-104A which was disallowed by the South Carolina Supreme Court in South Carolina Energy Users Committee vs. The South Carolina Public Service Commission. (Walker prefled direct testimony at p. 9, ll. 8-14). Ms. Walker further testified that since Order No. 2011-345, SCE&G has continued to "review, refine and update these owner's cost projections" and consequently the utility has identified an additional \$131.6 million in owner's costs. (Walker prefled direct testimony p. 10, l. 1- p. 11, l. 12). In fact, Mr. Byrne testified that SCE&G anticipates that its annual review of owner's costs for the nuclear generating plants will require SCE&G to petition the Commission annually to request additional owner's costs be placed in rates (Tr. at page 326, lines 14-18).

Dr. Mark Cooper, who testified on behalf of the Sierra Club, testified "[r]ushing to be among the first in line, for a design that had not been approved or implemented in the U.S., the

utility took on extraordinary risk, that it failed to include in its initial cost estimate. It now seeks to impose the costs of its imprudently rosy initial cost project with approval of cost overruns.”

Cooper prefiled direct testimony at p. 25). Dr. Cooper testified that the fact that SCE&G identified a series of risks associated with the construction of the two nuclear reactors in Jenkinsville, South Carolina does not exempt it from bearing some of the costs of those risks.

(Cooper prefiled direct testimony at p. 22). In particular, Dr. Cooper testified:

- The fact that there would be difficulties in finding adequately qualified and trained personnel was widely recognized.
- The fact that the supply chain was stretched thin was widely recognized.
- The fact that there would be bumps in the road of regulatory approval was also certainly predictable. The failure to comply with NRC requirements is the responsibility of the utility, not the ratepayers or the NRS.
- Given the history of nuclear reactor construction in the U.S. and around the world, the fact that requirements would evolve over time should have been foreseen and included in the cost estimate.

(Cooper prefiled direct testimony at pp. 22-23).

Dr. Cooper testified to the fact that SCE&G’s hope that other utilities would help defray the cost of developing a completed AP 1000 Westinghouse design was poor judgment on its part. SCE&G’s cost estimates should have reflected the possibility that SCE&G would need to complete the project on its own and that it was unreasonable for SCE&G to hope that four other utilities would share the costs in finishing the design work, a risk SCE&G chose to take.

(Cooper prefiled direct testimony at p. 23). SCE&G has discovered that its IT systems are outdated and need updating. Dr. Cooper testified that it was in fact Unit I which required the upgrade which would be reviewed in a general rate case. Instead, the utility seeks to shift the cost of upgrading its IT system at Unit I to its BLRA order which is not permitted by the BLRA.

(Cooper prefiled direct testimony at p. 23).

Dr. Cooper testified that given his extensive analysis of both the long-term history of nuclear construction and the development of recent nuclear construction proposals, he was of the opinion that every one of the causes of the cost overruns for which SCE&G was seeking recovery here should have been evident to a prudent utility at the time it filed its BLRA Application. Indeed, SCE&G charged ahead with a low-ball estimate of its capital costs in spite of this clear evidence of risk, underestimating the costs, which it now seeks recovery through a third bite of the apple under the BLRA. (Cooper prefiled direct testimony at p. 24).

Dr. Cooper testified that SCE&G has not shouldered any of the costs associated with the risks of its nuclear construction. Dr. Cooper compiled the following table reflecting the allocation of cost overruns:

Table 1: Allocation of Cost Overruns

	Change Orders	Owner Cost	Transmission	Total
Vendor	\$76	0	0	76
Ratepayers	\$156	276	21	453
Owner	\$0	0	0	0

With respect to the cost recovery system of the BLRA, Dr. Cooper testified as follows:

While the BLRA represented a dramatic change in the way rates are set for new nuclear reactors built in South Carolina, it did not abandon the fundamental concepts of just, reasonable and prudent that govern the setting of utility rates.

Advanced cost recovery under the BLRA gives nuclear costs very special treatment, but it is not a blank check and it does not diminish the obligation of the utility to ensure that it delivers the least cost electricity to ratepayers. (Cooper prefiled direct testimony at p. 3).

III. PROCEDURAL FINDINGS AND LEGAL STANDARDS

1. In Order No. 2009-104(A), dated March 2, 2009, the Commission approved a capital costs schedule for the construction of two 1,117 net megawatt nuclear power units to be located at the SCE&G's V.C. Summer Nuclear Station near Jenkinsville, South Carolina. The approved capital costs for the project totaled \$4.5 billion in 2007 dollars.

2. Under § 58-33-270(E), a utility may petition the Commission "for an order modifying any of the schedules, estimates, findings, class allocation factors, rate designs, or conditions that form part of any base load review order." The Commission shall grant the relief requested if, after a hearing, the Commission finds "that the evidence of record justifies a finding that the changes are not the result of imprudence on the part of the utility."

3. Under § 58-33-275 (E) in cases where a party proves by a preponderance of the evidence that there has been a material and adverse deviation from the approved schedules in a BLRA order, the Commission may disallow the additional capital costs that result from the deviation to the extent that the failure by the Utility to anticipate or avoid the deviation was imprudent.

IV. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. That SCE&G has petitioned the Commission for an order modifying its capital cost schedules of its BLRA order by including an additional \$283 million as capital costs together with authorized inflation. The general capital cost components of the petition are as follows:

Change Order 16	\$137.5 million;
Additional Owner's Cost	\$131.6 million
Transmission Costs	\$ 7.9 million
Cyber Security Costs	\$ 5.9 million
Change Order 12	\$135,573
Change Order 15	\$ 8,250
Total	\$283 million

2. That the additional \$283 million in costs have not been previously presented to the Commission for review and approval but rather exceed the capital costs approved through the BLRA and constitute material and adverse deviations from the approved schedules.

3. That the additional \$283 million in capital costs result in the failure of the utility to anticipate these costs.

4. That the additional \$283 million in capital costs were either anticipated or should have been anticipated by SCE&G in its 2008 BLRA application and are the result of imprudence on the part of the utility.

In particular, the Commission finds that the costs associated with Change Order 16 were anticipated, or should have been anticipated by SCE&G in its 2008 BLRA Application and therefore imprudent under the BLRA. The Company applied for an order under the BLRA without the benefit of an approved design for the Westinghouse AP1000 units. SCE&G undertook

to proceed with its BLRA application with full knowledge of the risk that the AP1000 design would prove more costly. Moreover, the Company assumed the risk of the additional cost associated with any delay in the issuance of a COL. The Company acknowledges in its testimony that the delay in the issuance of a COL was the result in whole or in part of SCE&G's delayed decision to site its transmission lines using existing rights-of-way as well as the delay in obtaining required wetlands certification. SCE&G knew that under the BLRA and this Order 2009-104(A) time was of the essence and SCE&G could have and should have anticipated that the EPA and Corps of Engineers would expect the Utility to conclusively demonstrate the wetlands impact of its transmission siting and in any event, anticipated delays in obtaining its wetlands certification. It is irrelevant that the macro corridor may be a prudent way to site transmission lines in other circumstances. For the purposes of the BLRA, SCE&G assumed the risk of the additional costs associated with Change Order 16 and contributed to the delay giving rise to these costs. The costs associated with Change Order 16 are not recoverable under the BLRA. See Sections 58-33-250(1), 58-33-275(E). Moreover, SCE&G has failed to demonstrate that the settlement agreement among SCE&G, Westinghouse and Santee Cooper was prudent and reasonable.

Similarly, SCE&G should have anticipated the additional \$131.6 million in owner's costs it seeks recovery of in this docket. First, it should be noted that SCE&G has filed petitions to modify the schedules approved in Order No. 2009-104(A) annually since the Commission issued its BLRA order. The Company should have anticipated these additional owner's costs in its 2008 Application as required by the BLRA. See Sections 58-33-250(2), 58-33-275(E). Nevertheless, the Commission allowed SCE&G to recover \$145 million in owner's costs in Order No. 2011-345 issued May 16, 2011. Yet, the record reflects that SCE&G underestimated the need for additional owner's costs by \$131.6 million dollars in Docket No. 2010-376-E and petitioned this Commission

for these additional costs less than ten months after the issuance of Order No. 2011-345. The record is devoid of any reasonable explanation of how SCE&G could have failed to anticipate \$131.6 million in owner's costs which it now seeks in this docket. These costs are not prudent or reasonable.

Likewise, the additional transmission costs could have been anticipated in 2008 in the Utility's BLRA Application. In addition, siting its transmission lines in existing easements and right of ways ensures that the wetlands issues are identified and addressed timely. Instead, SCE&G used a macro corridor approach to transmission siting which was rejected by the Corps of Engineers and EPA. The wetlands certificates were delayed and as a result, the COL was delayed. The proposed transmission costs are the result of SCE&G's delay. Moreover, SCE&G could and should have anticipated this delay. These costs are not prudent or reasonable.

Last, the additional costs sought for Cyber Security, Change Order 12 and Change Order 15 could have been anticipated in the 2008 Application as is borne out by the testimony of Dr. Cooper. These costs are not prudent or reasonable.

V. CONCLUSION OF LAW

The BLRA provides protections for both SCE&G and its ratepayers. SCE&G is granted the benefit of advance recovery of its nuclear construction costs in revised rates annually over the life of the construction project. Capital costs approved by a BLRA order are prudent and are not subject to further challenge. While the Company has the benefit of seeking recovery of additional costs after the issuance of the BLRA Order, the ratepayers are protected from having to pay for additional costs which could have been anticipated by the utility in its initial application. The BLRA does not excuse SCE&G from identifying its costs in its BLRA application because of inconvenience to the utility. Here the Company would have benefited from delaying its

application until it could fully and completely identify its costs. SCE&G could have anticipated in all of these costs for which it seeks recovery in this docket had it devoted sufficient time and energy to do so. Because SCE&G could have anticipated these costs in its initial application but failed to do so, they are not recoverable under the BLRA. See §58-33-275(E), §58-33-280(K). Further, the Company failed to establish that the additional capital costs requested were prudent or reasonable under traditional notions of regulated utility law. While the BLRA permits a utility to apply for modifications to the capital cost schedules in a base load review order which could not have been anticipated in its initial BLRA application, the BLRA does not provide for annual rate proceedings. On this record, the Commission is forced to conclude that Change Order No. 16, the owner's costs, transmission costs and other change orders are not prudent or reasonable.

Accordingly, the Petition herein shall be denied.

Now, therefore, IT IS HEREBY ORDERED:

That the Petition for updates and revisions to capital cost schedules is hereby denied.

BY ORDER OF THE COMMISSION:

David A. Wright, Chairman

ATTEST:

Randy Mitchell, Vice Chairman
(SEAL)

CERTIFICATE OF SERVICE

The undersigned employee of Elliott & Elliott, P.A. does hereby certify that (s)he has served below listed parties with a copy of the pleading(s) indicated below by mailing a copy of same to them in the United States mail, by regular mail, with sufficient postage affixed thereto and return address clearly marked on the date indicated below:

**RE: Petition of South Carolina Electric & Gas Company for
Updates and Revisions to Schedules Related to the
Construction of a Nuclear Base Load Generation Facility at
Jenkinsville, South Carolina
Docket No. 2012-203-E**

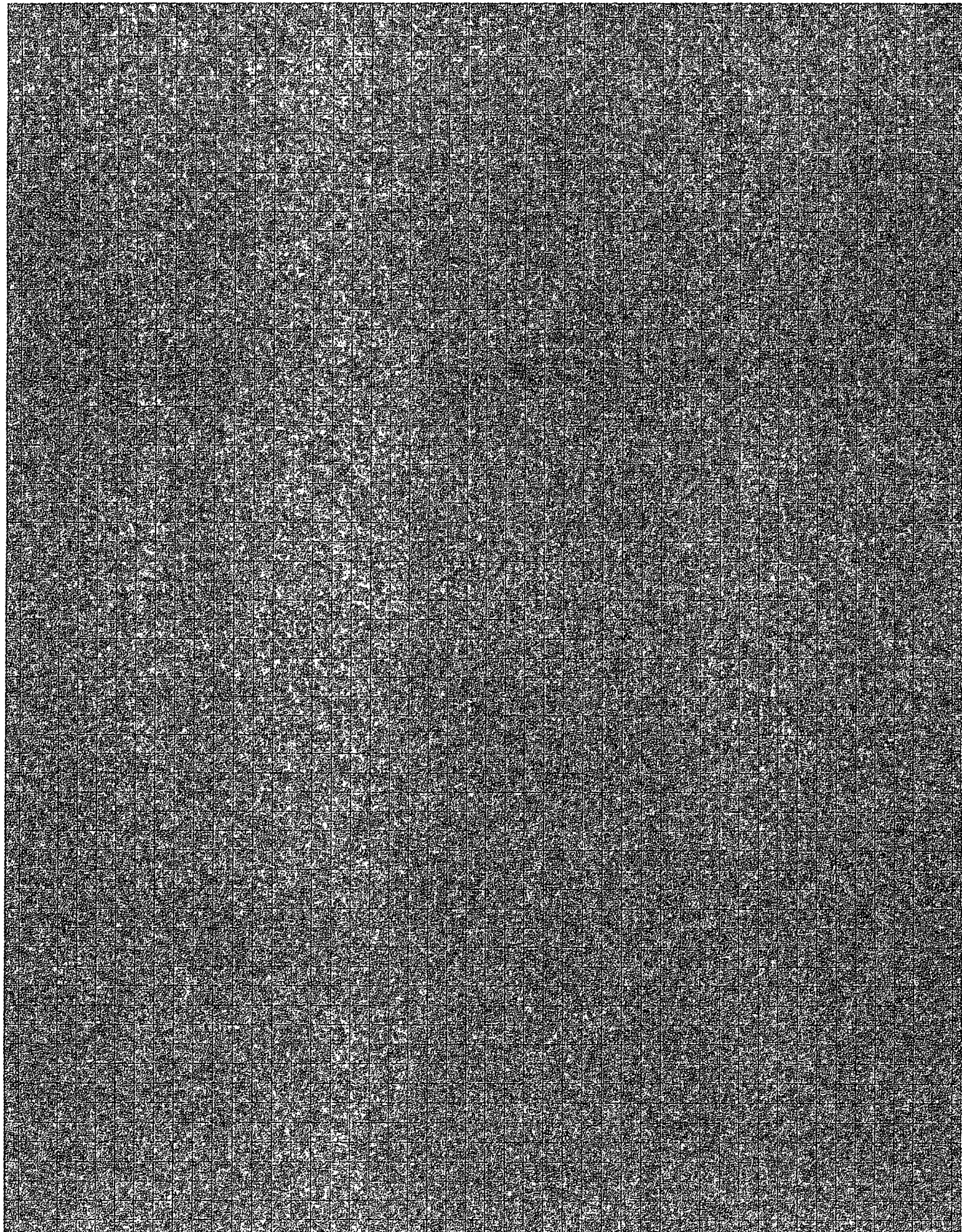
PARTIES SERVED:

Belton T. Zeigler, Esquire Gary Pope, Jr., Esquire Pope Zeigler, LLC P. O. Box 11509 Columbia, SC 29211	Jeffrey M. Nelson, Esquire Shannon B. Hudson, Esquire Courtney D. Edwards, Esquire Office of Regulatory Staff 1401 Main Street, Suite 900 Columbia, SC 29201
Robert Guild, Esquire Attorney at Law 314 Pall Mall Street Columbia, SC 29201	K. Chad Burgess, Esquire SCANA Corporation Mail Code C222 220 Operation Way Cayce, SC 29033-3701
Matthew W. Gissendanner, Esquire SCANA Corporation 220 Operation Way MC C222 Cayce, SC 29033-3701	Pamela Greenlaw 1001 Wotan Road Columbia, SC 29229

**PLEADING: PROPOSED ORDER DENYING PETITION FOR
UPDATES AND REVISIONS TO SCHEDULES**

October 26, 2012

Marcia W. Walters
Marcia W. Walters, Legal Assistant



RECEIVED

BEFORE

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THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA
SC PUBLIC SERVICE
COMMISSION

DOCKET NO.2012-203-E

In Re: Petition of South Carolina Electric &
Gas Company for Updates and Revisions to
Schedules Related to the Construction of a
Nuclear Base Load Generation Facility at
Jenkinsville, South Carolina)
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**PETITION FOR REHEARING OR
RECONSIDERATION BY
SIERRA CLUB**

Sierra Club, Intervenor in the above-referenced proceeding, hereby petitions the Commission pursuant to S.C. Code Ann. Section 58-27-2150 (Supp. 2011) and Rule 103-854 of the Commission's Rules, for rehearing or reconsideration of Order No. 2012-884, dated November 15, 2012, approving the Petition of South Carolina Electric & Gas Company for changes in the capital cost and construction schedules for its two unit V. C. Summer nuclear generating project, by adding some \$278 million in cost overruns to the previously approved capital cost budget; and a schedule delay of some eleven (11) months in the construction completion schedule.

Sierra Club urges the Commission to reconsider said Order, to correct the errors therein as set forth below, to reject said Petition and to require the Company to conduct and submit a full prudence review of abandoning the nuclear project in favor of a less costly alternative energy resource plan.

In support of this petition for rehearing or reconsideration of Order No. 2012-884, Sierra Club would respectfully show that:

1. The Commission erred in overlooking and misapprehending the nature and scope of the authority granted it by statute to modify its initial Base Load Review Order, Order No. 2009-104(A), applicable to this project.
2. The Commission erred in failing to properly apply the provisions of SC Code. Ann. §58-33-275 to SCE&G's Petition to include additional capital costs estimates in its Base Load Review Order.
3. The Commission erred in failing to conclude here, where it is proven by a preponderance of evidence that there has been a material and adverse deviation from the approved schedules, estimates and projections set forth in the Base Load Review Order, that it must disallow the additional capital costs that result from the deviation to the extent that the failure by the Utility to anticipate or avoid the deviation or to minimize the resulting expense was imprudent. S.C. Code Ann. §58-33-275(E).
4. The Commission erred in failing to conclude that SCE&G could, or should have anticipated or avoided the additional capital costs in question at the time of its initial Base Load Review Act (BLRA) application.
5. The Commission erred in failing to conclude that the evidence in the record compels a finding that in its rush to construct the nuclear plants, SCE&G sought and obtained its Base Load Review Order based on an incomplete, unapproved design for the Westinghouse AP 1000 model nuclear plant, while failing to anticipate and include adequate safeguards to avoid excessive additional capital costs.
6. The Commission erred in finding and concluding that the additional capital costs associated with Change Order 16 are reasonable and prudent and comport with the terms of the BLRA; where such costs were anticipated, or should have been anticipated

by SCE&G in its initial Base Load Review Act application, and are, therefore, imprudent under the BLRA. SCE&G assumed the risk of the additional costs associated with Change Order 16 which are not recoverable under the BLRA. Sections 58-33-250(1), 58-33-275(E).

7. The Commission erred in finding and concluding that the additional \$131.6 million in owner's costs requested in this docket are reasonable and prudent and comport with the terms of the BLRA; and in failing to find and conclude that SCE&G should have anticipated or avoided the additional \$131.6 million in owner's costs it seeks recovery of in this docket.

8. The Commission erred in finding and concluding the additional capital costs associated with transmission costs requested in this docket are reasonable and prudent and comport with the terms of the BLRA. The additional transmission costs could and should have been anticipated or avoided at the time of the Company's initial BLRA Application.

9. The Commission erred in finding and concluding that the additional costs sought for Cyber Security, Change Order 12 and Change Order 15 in this docket are reasonable and prudent and comport with the terms of the BLRA. The additional costs sought for Cyber Security, Change Order 12 and Change Order 15 could and should have been anticipated or avoided at the time of the Company's initial BLRA Application.

10. The Commission erred in failing to conclude that the BLRA requires consideration of the prudence of continuing to incur capital costs for a nuclear project where the evidence of material changed conditions compels the conclusion that incurring additional capital costs for constructing the project is now imprudent and where such

costs can be avoided by abandoning the nuclear project in favor of a less costly alternative energy resource plan.

10. The Commission erred in failing to conclude that the evidence in the record of material changed conditions regarding the costs of this project and feasible alternatives compels a finding that continuing to incur capital costs for the nuclear project is now imprudent where such costs can be avoided by abandoning the nuclear project in favor of a less costly alternative energy resource plan.

11. The Commission erred in interpreting the BLRA to preclude the consideration of "changes in fuel costs" in considering the prudence of abandoning construction of the nuclear project in favor of a less costly alternative energy resource plan.

12. The Commission erred in interpreting the BLRA to authorize the "routine" filing of capital cost update proceedings instead of requiring the utility to anticipate and avoid incurring imprudent costs to the detriment of ratepayers.

13. The Commission erred in interpreting the BLRA to preclude protecting ratepayers from imprudent capital costs of continued plant construction while authorizing the utility to recover even the costs of an abandoned nuclear plant project.

14. The Commission erred in concluding that the construction of the nuclear Units should continue and that the additional capital costs and schedule changes are not the result of imprudence on the part of SCE&G.

15. The Commission erred in rejecting the evidence presented by Sierra Club that the nuclear project was no longer prudent in light of available alternatives and finding that the evidence presented by SCE&G amply establishes the prudence of continued investment in the nuclear project.

16. The commission erred in finding that the evidence presented in this docket demonstrates that additional nuclear generation will bring considerable benefits of fuel diversity and the flexibility to respond to future environmental regulations to SCE&G's generation portfolio across a broad range of possible scenarios for fuel costs and environmental regulations.

17. The commission erred in finding that the Company made an affirmative and sufficient demonstration of the prudence of its nuclear construction program.

18. The Commission erred in concluding that the evidence in the record demonstrates that \$278.05 million in newly identified and itemized costs are the result of the normal evolution and refinement of construction plans and budgets for the Units and are not the result of imprudence on the part of SCE&G.

18. The Commission erred in concluding that these additional costs are reasonable, necessary and prudent costs that SCE&G is incurring as owner of the project to ensure that the project is constructed prudently, efficiently and economically, and to ensure that the Units can be operated and maintained safely and efficiently when they are completed.

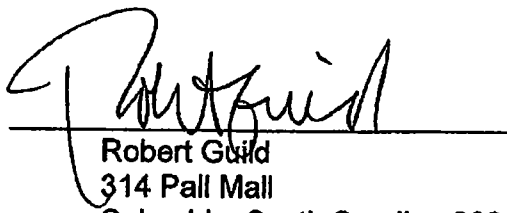
19. The Comm erred in concluding that the evidence in the record shows that the delay in the substantial completion of Unit 2 and the acceleration of the completion of Unit 3 supports updating the construction milestones for the Units and is not the result of any imprudence on the part of SCE&G.

20. The Commission erred, based on the evidence presented by Sierra Club and its expert, Dr. Mark Cooper, in failing to require SCE&G to undertake a thorough evaluation the prudence of abandoning the nuclear project in favor of a less costly

alternative energy resource plan.

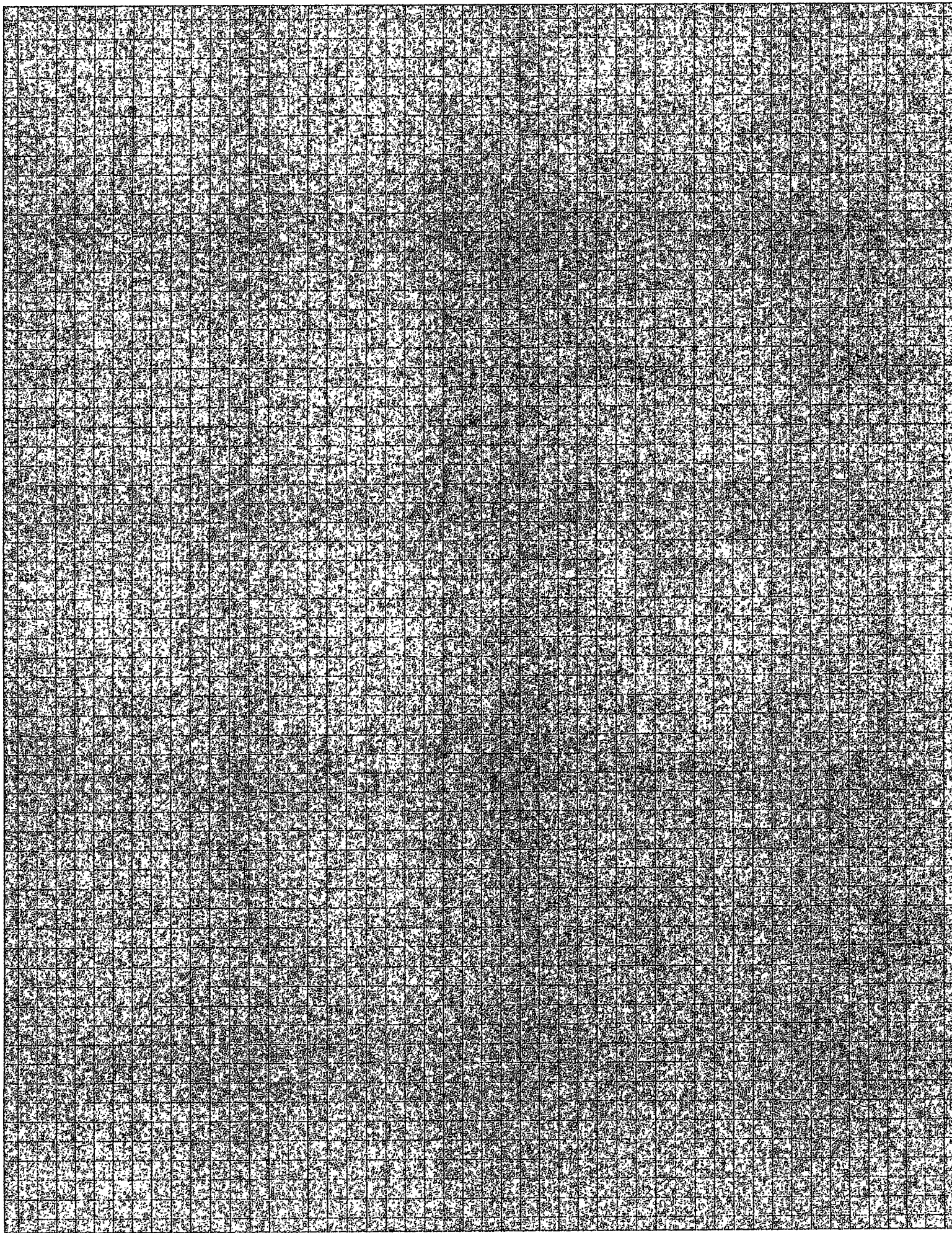
21. The Commission erred in its Order approving the Petition by SCE&G where said Order is arbitrary, capricious, an abuse of discretion, clearly erroneous, unsupported by substantial evidence, in violation of constitutional or statutory provisions, made upon unlawful procedure or affected by other error of law.

WHEREFORE: for the foregoing reasons, Sierra Club urges the Commission to reconsider said Order, to correct the errors therein as set forth below, to reject said Petition and to require the Company to conduct and submit a full prudence review of abandoning the nuclear project in favor of a less costly alternative energy resource plan.



Robert Guild
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Columbia, South Carolina 29201
(803) 252 1419
ATTORNEY FOR PETITIONER
SIERRA CLUB

November 26, 2012



IN THE MATTER OF:

SCEUC'S PETITION FOR REHEARING

1. The Commission found and concluded that the following cost updates proposed by SCE&G were reasonable and not the result of imprudence:

Change Order No. 16 to the EPC Contract:	\$137.5 million
Owner's Cost:	\$131.6 million
Transmission Cost:	\$ 7.9 million
Cyber Security:	\$ 0.9 million
Healthcare and Wastewater Piping:	\$ 0.1 million
TOTAL	\$278.05million

The Commission held:

Under S.C. Ann. Section §58-33-270(E), a utility may petition the Commission 'for an order modifying any of the schedules, estimates, findings, class allocation factors, rate designs, or conditions that form part of any base load review order.' The Commission shall grant the relief requested if, after a hearing, the Commission finds 'that the evidence of record justifies a finding that the changes are not the result of imprudence on the part of the utility'. (Order No. 2012-884 at p. 71).

In particular, the Commission found as follows:

The evidence in the record demonstrates that \$278.05 million in newly identified and itemized costs are the result of the normal evolution and refinement of construction plans and budgets for the Units and are not the result of imprudence on the part of SC&G. (Order No. 2012-884 at p. 72).

The Commission further found:

For the reasons set forth below, the Commission finds that the changes to the cost, with the exception of the cost of Phase II of the cyber-security project, and construction schedules proposed by SCE&G are reasonable and prudent and comport with the terms of the BLRA. (Order No. 2012-884 at p. 68).

Thus, the Commission held that approximately \$278.05 million of SCE&G's request in the docket was not the result of imprudence on the part of the utility and approved these costs as a part of the capital cost schedule for the units. (Order No. 2012-203-E at p. 73).

2. The Commission may exercise only that authority granted it under the Base Load Review Act ("BLRA"). South Carolina Electric & Gas Company v. South

Carolina Public Service Commission, supra; Nucor Steel v. South Carolina Public Service Commission, 310 SC 539, 426 SE 2nd 319 (1992).

The Base Load Review Act

The BLRA provides that, as long as a nuclear plant is constructed in accordance with the approved schedules, estimates and projections, as adjusted by the inflation indices, a utility must be allowed to recover its capital costs related to plant through revised rate filings §58-33-275(C). The purpose of the BLRA,

is to provide for the recovery of the prudently incurred costs associated with new base load plants, as defined in Section 58-33-220 of Article 4, when constructed by investor-owned electrical utilities, while at the same time protecting customers of investor-owned electrical utilities from responsibility for imprudent financial obligations or costs. Base Load Review Act Section 1(A).

To balance the interests of the utility and the rate payer, the General Assembly designed a specific and detailed statutory blueprint for establishing prudent costs to be recovered through revised rate filings. The Commission's authority to issue a base load review order is prescribed by the express terms of the BLRA.

A base load review order issued pursuant to the BLRA,

means an order issued by the commission pursuant to Section 58-33-270 establishing that if a plant is constructed in accordance with an approved construction schedule, approved capital costs estimates, and approved projections of in-service expenses, as defined herein, the plant is considered to be used and useful for utility purposes such that its capital costs are prudent utility costs and are properly included in rates. S.C. Code Ann. Section 58-33-220(4).

If a utility establishes that its nuclear plant is constructed in accordance with (1) an approved construction schedule, (2) approved capital costs estimates, and (3) approved projections of in-service expenses, the nuclear plant is considered to be used and useful for utility purposes and are properly included in rates, §58-33-220(4).

The BLRA expressly sets out the factual showing necessary for a base load review order. S.C. Code Ann. §58-33-250 provides (in its pertinent part):

The application for a base load review order under this article shall include:

- (1) information showing the anticipated construction schedule for the plant; [Emphasis added]
- (2) information showing the anticipated components of capital costs and the anticipated schedule for incurring them; [Emphasis added]

The BLRA provides that as circumstances warrant, a utility may petition the Commission for an order modifying its schedules in the Base Load Review Order. However, the proposed changes may not be the result of imprudence on the part of the utility. Sections 58-33-270(E), 58-33-275(E). The definition of the term imprudence as it applies to the instant docket can be found in Section 58-33-275(E) which reads:

In cases where a party proves by a preponderance of the evidence that there has been a material and adverse deviation from the approved schedules, estimates, and projections set forth in Section 58-33-270(B)(1) and 58-33-270(B)(2), as adjusted by the inflation indices set forth in Section 58-33-270(B)(5), the commission may disallow the additional capital costs that result from the deviation, but only to the extent that the failure by the utility to anticipate or avoid the deviation, or to minimize the resulting expense, was imprudent considering the information available at the time that the utility could have acted to avoid the deviation or minimize its effect.

Therefore, this Commission may disallow additional capital costs which result from SCE&G's failure to anticipate or avoid the additional costs which it seeks here. See also Section 58-33-280(K) which provides that where a plant is abandoned after a BLRA order, the utility's recovery of capital costs may be disallowed to the extent that the failure by the utility to anticipate or avoid the allegedly imprudent costs was imprudent considering the information available at the time the utility could have acted to avoid or

minimize the costs. See also Sections 58-33-225(F) and (G) defining imprudence in connection with a project development order as the failure to avoid additional costs.

The BLRA provides the utility with a novel way to recover the costs of nuclear construction by permitting advanced cost recovery. As long as the plant is constructed within approved schedules, estimates and projections set forth in Sections 58-33-270(B)(1) and 58-33-270(B)(2), the utility must be allowed to recover its capital costs related to the plant through revised rate filings. However, the BLRA does not give a utility the authority to recover additional costs which could have been anticipated at the time of the BLRA application, and thus the provisions of Section 58-33-270(E) do not permit frequent or even annual applications to amend an order issued under the BLRA for capital costs overlooked by the utility in its BLRA application.

3. The Commission overlooked and misapprehended the nature of the authority granted it by statute to modify its Order No. 2009-104(A) (Base Load Review Order).

The Commission failed to apply the provisions of SC Code Ann. §58-33-275 to SCE&G's Petition to include additional capital costs estimates in its Base Load Review Order. As stated above, a Base Load Review Order shall constitute a final and binding determination that the plant is used and useful for utility purposes and that its capital costs are prudent utility costs properly included in rates so long as the plant is constructed within the parameters of the approved construction schedule and the approved capital costs estimates. S.C. Code Ann. §58-33-275 (A). So long as the plant is constructed in accordance with the approved schedules, estimates and projections set out in the Base Load Review Order, SCE&G must be allowed to recover its capital costs related to plant

through revised rate filings or general rate proceedings. S.C. Code Ann. §58-33-275(C). In cases such as the one before the Commission where it is proven by a preponderance of evidence that there has been a material and adverse deviation from the approved schedules, estimates and projections set forth in the Base Load Review Order, the Commission must disallow the additional capital costs that result from the deviation to the extent that the failure by the utility to anticipate or avoid the deviation or to minimize the resulting expense was imprudent. S.C. Code Ann. §58-33-275(E).

Here, it is uncontested that the \$278.05 million in additional costs are a material and adverse deviation from the approved schedules, estimates and rejections. Indeed, the Commission so found in Order No. 2012-884 at p. 71. For the reasons set out at trial in SCEUC's proposed Order and hereafter, it is clear that SCE&G could or should have anticipated the costs in question. First, in its rush to construct the nuclear plants, SCE&G sought and obtained its Base Load Review Order based on an incomplete, unapproved design for the Westinghouse AP 1000. It cannot reasonably be argued that SCE&G did not or could not anticipate that the final design would prove to be more costly than anticipated. Yet, SCE&G filed its Application under the BLRA failing to anticipate adequate safeguards to avoid excessive costs. Similarly, SCE&G would now suggest that it had no statutory obligation to anticipate its owner costs prior to filing its application under the BLRA and that the statute authorizes the utility to make annual application to the Commission to add construction costs that it failed to anticipate in its 2008 BLRA application. In accepting SCE&G's argument, the Commission concludes that proceedings such as that in the instant docket will become routine so as to permit a utility to file annual rate proceedings under the Base Load Review Act. The Commission held:

Update proceedings are likely to be a routine part of administering BLRA projects going forward (including future projects proposed by other electric utilities), such that under the Sierra Club's argument, the prudence of the decision to build the plant will be open to repeated relitigation during the construction period if a utility seeks to preserve the benefits of the BLRA for its project. Reopening the initial prudency determinations each time a utility is required to make an update filing would create an outcome that the BLRA was intended to prevent and would defeat the principal legislative purpose in adopting the statute. (Order No. 2012-884 at p. 17).

The BLRA was designed to give the utility the benefit of an initial determination of prudency and advanced recovery for its anticipated costs through annual revised rates. However, the BLRA also protects the ratepayer by requiring the utility to identify its anticipated costs in advance and denying the utility to recover cost overruns. Thus, both the utility and the ratepayer have certainty with respect to nuclear construction costs. While the Commission correctly concludes that "the General Assembly sought to mitigate such uncertainty by providing for a comprehensive, fully-litigated and binding prudency review before major construction of a base load generating facility begins . . .," the Commission, in its Order confers the benefit of this certainty of construction costs only on the utility to the detriment of the ratepayer. (See Order No. 2012-884 at p. 16). Although S.C. Code Ann. §58-33-270(E) permits the utility to petition the Commission to modify its schedules and estimates, this section must not be read to authorize annual rate proceedings as concluded by the Commission. Thus, a petition under S.C. Code Ann. §58-33-270(E) must be construed in light of S.C. Code Ann. §58-33-275(E) which prohibits recovery of the additional costs such as those requested here.

To construe the BLRA so as to permit SCE&G to obtain routine recovery of increased construction costs or cost overruns in rates deprives ratepayers of the protections afforded under the BLRA.

4. That the additional \$283 million in capital costs were either anticipated or should have been anticipated by SCE&G in its 2008 BLRA application and are the result of imprudence on the part of the utility.

- a. The Commission erred in finding and concluding the costs associated with Change Order 16 are reasonable and prudent and comport with the terms of the BLRA. The \$137.5 million in costs associated with Change Order 16 were anticipated, or should have been anticipated by SCE&G in its 2008 BLRA Application and are therefore imprudent under the BLRA. The Company applied for an order under the BLRA without the benefit of an approved design for the Westinghouse AP1000 units. SCE&G undertook to proceed with its BLRA application with full knowledge of the risk that the AP1000 design would prove more costly. Moreover, the Company assumed the risk of the additional cost associated with any delay in the issuance of a Combined Operating License ("COL"). The Company acknowledges in its testimony that the delay in the issuance of a COL was the result in whole or in part of SCE&G's delayed decision to site its transmission lines using existing rights-of-way and the delay in obtaining required wetlands certification. SCE&G knew that under the BLRA and Order No. 2009-104(A) time was of the essence, and SCE&G could have and should have anticipated that the EPA and Corps of

Engineers would expect the utility to conclusively demonstrate the wetlands impact of its transmission siting and in any event, anticipated delays in obtaining its wetlands certification. It is irrelevant that the macro corridor may be a prudent way to site transmission lines in other circumstances. For the purposes of the BLRA, SCE&G assumed the risk of the additional costs associated with Change Order 16 and are not recoverable under the BLRA. Moreover, SCE&G has failed to demonstrate that the settlement agreement among SCE&G, Westinghouse and Santee Cooper was prudent and reasonable. See Sections 58-33-250(1) and (2), 58-33-275(E).

- b. The Commission erred in finding and concluding the additional \$131.6 million in owner's costs requested in this docket are reasonable and prudent and comport with the terms of the BLRA. SCE&G should have anticipated the additional \$131.6 million in owner's costs it seeks recovery of in this docket. First, it should be noted that SCE&G has filed petitions to modify the schedules approved in Order No. 2009-104(A) annually since the Commission issued its BLRA order. The Company should have anticipated these additional owner's costs in its 2008 Application as required by the BLRA. Nevertheless, the Commission authorized SCE&G to recover an additional \$145 million in owner's costs in Order No. 2011-345 issued May 16, 2011 in Docket No. 2010-376-E. Yet, the record in this docket reflects that SCE&G underestimated the need for additional owner's costs by \$131.6 million dollars in Docket No.

2010-376-E and petitioned this Commission for these additional costs less than ten months after the issuance of Order No. 2011-345. The record is devoid of any reasonable explanation of how SCE&G could have failed to anticipate \$131.6 million in owner's costs which it now seeks in this docket. These costs are neither reasonable nor prudent. See Sections 58-33-250 (1) and (2), 58-33-275(E).

- c. The Commission erred in finding and concluding that the additional \$7.9 million in transmission costs requested in this docket are reasonable and prudent and comport with the terms of the BLRA. The additional transmission costs could have been anticipated in 2008 in the Utility's BLRA Application. In addition, siting its transmission lines in existing easements and right-of-ways would have ensured that the wetlands issues were identified and addressed timely. Instead, SCE&G used a macro corridor approach to transmission siting which was rejected by the Corps of Engineers and EPA. The wetlands certificates were delayed and as a result, the COL was delayed. The proposed transmission costs are the result of SCE&G's delay. Moreover, SCE&G could and should have anticipated this delay. These costs are neither prudent nor reasonable. See Sections 58-33-250 (1) and (2), 58-33-275(E).
- d. The Commission erred in finding and concluding the additional costs sought for Cyber Security, Change Order 12 and Change Order 15 in this docket are reasonable and prudent and comport with the terms of the BLRA. The additional costs sought for Cyber Security, Change Order 12

and Change Order 15 could have been anticipated in the 2008 Application as is borne out by the testimony of Dr. Mark Cooper. These costs are neither prudent nor reasonable. See Sections 58-33-250 (1) and (2), 58-33-275(E).

Therefore, the Commission erred in holding that approximately \$278.05 million of SCE&G's request in the docket was not the result of imprudence on the part of the utility, in approving these costs as a part of the capital cost schedule for the nuclear units and in permitting SCE&G to include these costs in rates. (Order No. 2012-203-E at p. 73).

5. Further, the Commission erred in failing to require SCE&G to undertake an evaluation of the need for the two Westinghouse AP 1000 nuclear generating generators. Through its witness Dr. Cooper, the intervenor Sierra Club raised the question of the prudence of constructing the additional capacity to be generated by the nuclear plants. SCE&G in response to the Sierra Club evidence, introduced into the record an analysis of completing the nuclear construction (Lynch Exhibit 9). However, the Lynch analysis was far from complete in that it simply compared the cost of constructing two nuclear generating plants with the cost of constructing two gas-fired generating plants. As the Commission is aware, SCE&G is seeking recovery of revenues lost from the termination of a contract with a North Carolina electric cooperative of 250 megawatts of generating capacity from its Jasper combined cycle generator. See *Application of South Carolina Electric & Gas Company for Increases and Adjustments in Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel* (Docket No. 2012-218-E). The SCE&G analysis failed to take into consideration the overcapacity which currently exists in SCE&G's system in Dr. Lynch's

analysis. Further, the analysis failed to consider the prudence of constructing one of the nuclear generators and mothballing the second under construction. Last, SCE&G's analysis failed to consider building natural gas-fired plants as the need for capacity arose as opposed to over-constructing generating capacity by proceeding with the construction of the two nuclear generators. Accordingly, the record in this docket fails to support the Commission's finding and conclusion for the need for and the prudence of the construction of the excess capacity created by the construction of the two nuclear generating plants in this docket.

For the foregoing reasons, as well as those set out at trial and in its proposed order submitted October 26, 2012, the South Carolina Energy Users Committee respectfully requests that the Commission rehear those issues set out above, reconsider Order No. 2012-884 respecting those issues and re-issue its order consistent with the arguments set out herein.

Respectfully submitted,



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Attorney for South Carolina Energy
Users Committee

Columbia, South Carolina
November 18, 2012

**EXCERPTS FROM
TRANSCRIPT OF
TESTIMONY AND PROCEEDINGS
OCTOBER 2 – 3, 2012
DOCKET NO. 2012-203-E**

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

HEARING # 12-11315 OCTOBER 2, 2012 9:30 A.M.

DOCKET NO. 2012-203-E:

SOUTH CAROLINA ELECTRIC & GAS COMPANY - Petition for Updates and
Revisions to Schedules Related to the Construction of a Nuclear
Base Load Generation Facility at Jenkinsville, South Carolina

TRANSCRIPT OF TESTIMONY
AND PROCEEDINGS

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HEARING BEFORE: David A. WRIGHT, CHAIRMAN, Randy MITCHELL,
VICE CHAIRMAN; and COMMISSIONERS John E. 'Butch' HOWARD, G.
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WHITFIELD, and Nikiya 'Nikki' HALL

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1 MR. BURGESS: We have no opening statement.
2 We're ready to call our first witness after Mr.
3 Guild's done.

4 CHAIRMAN WRIGHT: Mr. Guild?

5 MR. GUILD: Mr. Chairman, would the Chair
6 prefer I go to the lectern?

7 CHAIRMAN WRIGHT: It would be better, yes.

8 MR. GUILD: Good morning, Mr. Chairman and
9 members of the Commission. It's a pleasure to
10 appear before you again. Today, I appear on behalf
11 of the Sierra Club.

12 Sierra Club, as most of you must know, is the
13 nation's oldest, largest, and we'd like to think
14 most influential conservation and environmental
15 organization. In South Carolina, we have over
16 5,000 members, and the club is actively a
17 participant in clean energy advocacy and seeks to
18 participate in the public discourse about how to
19 plan for a secure and sustainable energy future for
20 South Carolina.

21 The club has a national energy resource policy
22 which the parties would point to in the course of
23 the proceedings, and that policy is an ambitious
24 one that advocates that we work diligently to
25 decarbonize our energy supply by the year 2050 to

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1 address the pressing global challenge of climate
2 crisis and reduce greenhouse gas production.

3 In keeping with that ambitious goal, the club
4 has a series of electric generation sources that it
5 prefers, a series of sources that it opposes, and a
6 series of sources that it neither opposes nor
7 supports but advocates consideration on a carefully
8 focused case-by-case basis. And of those sources,
9 coal and new nuclear are in the category of sources
10 that the club opposes, for reasons that we will
11 explain. We support aggressive energy efficiency
12 and a move toward renewables, including wind and
13 solar, as the energy future for our country and for
14 our State.

15 With regard to other sources, including
16 natural gas -- which is becoming increasingly the
17 focus of the utility industry's attention -- we
18 neither oppose nor support natural gas, but
19 recognize that it may play a role as a transitional
20 source of fuel because of its lower carbon
21 footprint and its price attractiveness.

22 Now, the issues in this case revolve around
23 the question of prudence. Prudence is defined by
24 some as acting with or showing care and thought for
25 the future.

1 know what? -- it's already 2012. I think we should
2 look at the 2012 costs.

3 Categorically, they are requesting only an
4 updated cost schedule, which doesn't alter the
5 estimated capital cost schedule for the units of
6 \$4.5 billion dollars, but changes the forecast
7 timing of cash flow. All right. As a layperson, I
8 have to say that's either a cost overrun, or we
9 don't know what the cash flow pot -- what the pot
10 is that this cash is supposed to flow from.

11 Thank you. And thank you for your indulgence.

12 CHAIRMAN WRIGHT: Thank you, Ms. Greenlaw.

13 ORS?

14 MS. HUDSON: ORS has no opening. Thank you.

15 CHAIRMAN WRIGHT: Very good. Mr. Burgess,
16 call your first witness.

17 MR. BURGESS: SCE&G calls its CEO, Mr. Kevin
18 Marsh, to the stand.

19 CHAIRMAN WRIGHT: Good morning.

20 MR. MARSH: Good morning.

21 [Witness sworn]

22 THEREUPON came,

23 K E V I N B . M A R S H ,

24 called as a witness on behalf of the Petitioner, South
25 Carolina Electric & Gas Company, who, having been first duly

1 sworn, was examined and testified as follows:

2 **DIRECT EXAMINATION**

3 **BY MR. BURGESS:**

4 **Q** Would you please state your name for the record?

5 **A** Kevin Marsh.

6 **Q** And by whom are you employed and in what capacity?

7 **A** I'm employed by SCANA Corporation as the chief executive
8 officer and president.

9 **Q** Mr. Marsh, have you prepared or caused to be prepared
10 under your direct supervision 32 pages of direct
11 testimony which has been prefiled in this docket?

12 **A** Yes, I have.

13 **Q** And do you have any changes or corrections that you
14 would like to make to that testimony?

15 **A** I do not.

16 **MR. BURGESS:** Mr. Chairman, at this time we
17 would like to move into the record of evidence the
18 prefiled direct testimony of Kevin Marsh, as if
19 given orally from the stand.

20 **CHAIRMAN WRIGHT:** Mr. Marsh's prefiled
21 testimony will be entered into the record as if
22 given orally from the stand.

23 *[See pgs 40-71]*

24 **MR. BURGESS:** And, Mr. Chairman, in advance of
25 this hearing, we had communications with David

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1 Butler, and we indicated to him and made all the
2 other parties aware that Mr. Marsh would also be
3 delivering his rebuttal at this time, so I'll move
4 into the rebuttal, with your permission.

5 CHAIRMAN WRIGHT: Go ahead.

6 BY MR. BURGESS:

7 Q Mr. Marsh, have you also prepared or caused to be
8 prepared and filed in this docket 15 pages of rebuttal
9 testimony?

10 A I did.

11 Q And do you have any changes or corrections that you'd
12 like to make to your rebuttal testimony?

13 A No, I don't.

14 MR. BURGESS: Mr. Chairman, at this time we
15 would like to move into the record of evidence the
16 rebuttal testimony of Kevin Marsh, as if given
17 orally from the stand. And we would also request
18 that, as the court reporter builds the record, the
19 transcript in this proceeding, if she would be
20 given leave by the Chair to insert the testimony in
21 chronological order as it comes in to this
22 Commission.

23 CHAIRMAN WRIGHT: Mr. Marsh's rebuttal
24 testimony will be entered into the record as if
25 given orally from the stand.

[See pgs 75-89]

And it will be noted that the court reporter
will do as you asked, including it in the timeline.

MR. BURGESS: Thank you, Mr. Chairman.

BY MR. BURGESS:

Q Mr. Marsh, have you prepared a summary of your direct
testimony?

A Yes, I have.

Q Would you please deliver that, at this time?

A Glad to. Good morning, Mr. Chairman and members of the
Commission.

In this proceeding, SCE&G seeks approval of updated
capital cost and construction schedules for the two new
nuclear units that it is building in Jenkinsville, South
Carolina. These cost schedules were first presented to
the Commission in May of 2008 and were approved under
the Base Load Review Act, or BLRA, in Order No. 2009-
104(A). They were based on construction cost schedules
as well as forecasts of owners' costs and transmission
costs that created -- that were created during 2005-2008
while the decision to build the units was being
evaluated.

Since the initial BLRA proceedings, SCE&G has come
to the Commission twice to update the cost and
construction schedules for the units. In 2009, SCE&G

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1 updated the construction schedule and associated cash-
2 flow forecast to reflect issuance of the initial site-
3 specific, integrated construction schedule for the
4 project by Westinghouse/Shaw. In the 2009 filing, the
5 timing of cash flows for the project were adjusted, but
6 the total forecasted cost for the units of \$4.5 billion
7 in 2007 dollars did not change.

8 In 2010, consistent with the decision of the South
9 Carolina Supreme Court in South Carolina Energy Users'
10 Committee versus South Carolina Public Service
11 Commission, the company removed the owner's contingency
12 costs from the prior cost forecast. In addition, in the
13 2010 update proceeding, the company identified and
14 itemized approximately \$174 million in costs to specific
15 cost categories for the project which would have been
16 accounted for using owner's contingency costs before the
17 court decision. As a result, in Order No. 2011-345, the
18 Commission approved cost schedules for the project that
19 reduced the approved cost estimate \$4.3 billion dollars.

20 In this proceeding, we are presenting updated
21 capital cost forecasts for the units that identify an
22 additional \$283 million in prudent and necessary costs
23 for the project. If the Commission agrees with these
24 changes, the approved capital cost for the units would
25 be \$4.5 billion, which is approximately \$18 million more

1 than the cost in 2007 dollars that was approved in the
2 forecast of 2008. Because escalation has been less than
3 anticipated, the cost of the units in future dollars has
4 declined since 2008 from \$6.3 billion, as reflected in
5 Order No. 2009-104(A), to \$5.8 billion, a reduction of
6 approximately \$550 million.

7 In this proceeding, SCE&G is presenting testimony
8 from four other witnesses: Mr. Byrne, who is president
9 for Generation and Transmission, and the chief operating
10 officer of SCE&G, will testify concerning the change
11 orders to the Engineering, Procurement, and Construction
12 Agreement -- or EPC contract -- that are reflected in
13 the current cost schedules. Mr. Byrne will also sponsor
14 the new construction schedule for the units, based on
15 the COL issuance date of March 30, 2012. This schedule
16 accelerates the completion of the project as a whole by
17 seven and a half months while delaying the completion
18 date of Unit 2 by 11½ months. Accelerated construction
19 of Unit 3 increases construction efficiencies by
20 reducing the gap in the construction schedule between it
21 and Unit 2. This reduces the cost of the overall plan
22 by \$16 million.

23 Mr. Byrne will also provide the Commission with an
24 update on the status of the construction of the units.
25 Such an update is required annually by Order No. 2009-

1 104(A).

2 SCE&G's next witness will be Mr. David Lavigne, who
3 is the general manager for Operational Readiness in the
4 New Nuclear Development -- or NND -- group. Changes to
5 the staffing plans are a principal driver of the
6 adjustment to owners' costs, which is the second-largest
7 element in the cost adjustments proposed here.

8 As the Commission is aware from the transmission
9 siting applications that SCE&G has filed in recent
10 months, much of the design and routing work for the
11 transmission improvements related to the project has
12 been done. As a result, we have refined our estimates
13 for the cost of these projects. The changes in
14 transmission costs represent only \$7.9 million, with a
15 total for the total adjustment to the cost forecast.

16 Mr. Clay Young, who is manager of Transmission
17 Planning for SCE&G, will testify concerning the status
18 of the transmission project associated with the units
19 and the revisions to the cost forecasts for those
20 projects.

21 Ms. Walker is vice president for Nuclear Finance
22 Administration at SCANA. She sponsors the current cost
23 schedules for the project and will present accounting,
24 budgeting, and forecasting information supporting the
25 reasonableness and prudence of the adjustments in the

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1 cost forecasts. Ms. Walker also testifies in further
2 detail concerning changes in our owners' cost forecast,
3 other than those related to the hiring, staffing, and
4 training costs Mr. Lavigne will discuss.

5 As CEO of SCANA, it is my testimony that the
6 project is proceeding satisfactorily and that the
7 adjustments in construction schedules and cost forecasts
8 that are presented here are a normal and expected part
9 of managing a 12-year, \$5.8 billion project.

10 To date, the project team has successfully resolved
11 or mitigated many of the most important challenges that
12 were identified in 2008 as applying to the initial
13 phases of the project. Those include, one, the
14 challenges associated with the initial licensing and
15 permitting for the project; two, the challenges
16 associated with completing the design of the AP1000
17 units; three, the challenges associated with initial
18 procurement and supply chain management for components
19 and equipment for the units; four, the challenges
20 associated with the initial site work; and, five, the
21 challenges associated with establishing support in the
22 financial community for the project.

23 We believe that we are well positioned to complete
24 these units at a reasonable cost and on a reasonable
25 schedule to meet the needs of our customers. Our goal

1 in building these units remains the same: When they are
2 completed, SCE&G's customers will benefit from an
3 additional 1,229 megawatts of efficient and zero-air-
4 emissions nuclear generation that we expect to be
5 available to supply their needs for 60 years. In large
6 part because of the units, SCE&G projects that, in 2019,
7 it will have reduced carbon emissions by 54 percent
8 compared to their 2005 levels, and by 35 percent
9 compared to their levels in 1995.

10 We also project that, in 2019, we will have a
11 generation portfolio with a balanced mix of fuel
12 sources. On a capacity basis, our generation mix will
13 be 27 percent coal, 28 percent natural gas, 31 percent
14 nuclear, and 14 percent hydrocarbons -- hydro and
15 biomass. Having a large block of reliable and efficient
16 nuclear generation will allow SCE&G to respond to
17 changing conditions in future markets in a way that no
18 other generation source would. It will mitigate the
19 risk our customers bear from future fossil-fuel price
20 volatility, future constraints on the supply or
21 deliverability of fossil fuels, future costs imposed on
22 carbon emissions, and future limitations on other
23 fossil-fuel air emissions. The units will mitigate the
24 risk over an expected life of 60 years. The alternative
25 to the units would be meeting our customers' demand by

1 increasing reliance on fossil fuels or economically
2 unproven alternative energy sources. In our view, that
3 would be a very risky strategy over the long run.

4 SCE&G remains confident that our choice of nuclear
5 generation to meet the needs of our system is the right
6 choice and positions us and our customers well to meet
7 the challenges of an uncertain energy future long-term.

8 In my testimony, I also review several of the major
9 commitments that SCE&G has made since 2008 to the
10 Commission, ORS, and the people of South Carolina,
11 related to the units. In 2008, SCE&G stated that it
12 would resolve the licensing and permitting issues
13 related to the units and obtain the COL to be able to
14 construct the units within the 18-month scheduling
15 contingency that the Commission approved in Order No.
16 2009-104(A). While the COL was delayed, as Mr. Byrne
17 will testify, we have nonetheless obtained it within the
18 18-month scheduling contingency, as indicated, and are
19 proceeding with the project under a schedule that is
20 accelerated by seven and a half months.

21 SCE&G also stated in 2008 that it would use the
22 provisions of the EPC contract to manage and control
23 construction cost and price risk on the project in a way
24 that reduced our exposure to future price increases. We
25 have delivered on that commitment. We began with an EPC

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1 contract that gave us pricing protection in the form of
2 fixed or firm pricing on more than 50 percent of the EPC
3 costs for the units. In 2010, we negotiated an
4 amendment to the contract to shift an additional \$315
5 million in EPC costs to the firm/fixed categories. At
6 the end of second quarter of 2012, only a little more
7 than one-fourth of the total EPC contract cost remains
8 to be spent in categories that are not subject to fixed
9 or firm pricing limitations. Furthermore, in the recent
10 change-order negotiations, we convinced
11 Westinghouse/Shaw to give us a fixed escalation rate on
12 all remaining firm costs that had been subject to Handy
13 Whitman escalation indices. As a result, none of our
14 remaining firm cost categories under the EPC are subject
15 to variable escalation. Moreover, in settling
16 Westinghouse/Shaw's claims related to the COL, design
17 issues, and other issues, we were able to reach a
18 reasonable and favorable compromise of these claims and
19 eliminate from the project the threat of a divisive and
20 distracting lawsuit between the principals at this
21 critical stage in the project. Because we were
22 successful in these negotiations, SCE&G was able to give
23 Westinghouse/Shaw full notice to proceed with
24 construction shortly after the COL was issued.

25 In 2008, we identified the challenges that the

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1 nuclear industry faced in reestablishing a nuclear
2 supply chain for new construction that could meet
3 stringent standards of quality assurance and quality
4 control -- or QA/QC -- in the nuclear field. We
5 committed our company to diligently working to identify
6 and resolve QA/QC issues in our supply chain. Through
7 the work of NND personnel in support of the quality
8 programs at Westinghouse/Shaw, QA/QC problems have been
9 identified early in the project, and appropriate
10 attention and support has been provided to suppliers
11 experiencing difficulties. We understand that we must
12 maintain oversight and accountability. We intend to
13 maintain a high level of diligence on our contractors
14 and suppliers, and the quality of their work. Part of
15 the reason we are increasing NND staffing and associated
16 cost protections is to allow us to do so in an effective
17 way.

18 In the 2008 proceeding, SCE&G made the commitment
19 to intensify its energy efficiency and demand-side
20 management -- or DSM -- programs. Implementation of
21 these programs is underway and ongoing. To date, SCE&G
22 has invested \$11 million in DSM programs which have
23 reduced system demand by approximately 10 megawatts.

24 In the 2008 BLRA hearing, we testified that the
25 decision to build the units notwithstanding, SCE&G would

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1 not ignore the potential contribution that alternative
2 energy sources could provide to its system. In 2011,
3 SCE&G installed the largest thin-laminate solar
4 generation system in the Southeast and the sixth largest
5 such system in the nation. The installation covers ten
6 acres on a rooftop at Boeing's North Charleston
7 production facility and, at peak capacity, generates 2.6
8 megawatts, or enough power to serve 250 average homes on
9 SCE&G's system.

10 In partnership with Duke, Progress, Office of
11 Regulatory Staff, and the South Carolina Energy Office,
12 SCE&G created Palmetto Clean Energy -- or PaCE -- to
13 provide customers a voluntary program to promote the
14 development of renewable energy resources. Currently,
15 150 customers own allowable generation and participate
16 in SCE&G's net metering programs.

17 During 2008, SCE&G recognized the financial
18 challenge of supporting the capital investment
19 represented by this project. As of the end of the
20 second quarter 2012, SCE&G will have successfully
21 financed the investment of approximately \$1.5 billion in
22 capital in construction of the units, which represents
23 approximately 25 percent of the current -- excuse me --
24 approximately 26 percent of the current cost forecast.
25 We have done so while maintaining a solid investment-

1 grade credit rating, and our last two bond financings
2 have been at some of the lowest interest rates in the
3 history of the electric utility industry. These low
4 rates benefit our customers directly, since lower costs
5 of debt translate directly into lower rates under the
6 BLRA and under general ratemaking principles.

7 The investment community has supported the project
8 in large part because of the quality of oversight
9 provided by this Commission and ORS, as well as the
10 predictability and fairness of regulation in this State.
11 The investment community is very comfortable with the
12 consistency and predictability of our annual revised
13 rates filings and update filings, and with the way this
14 project is being managed from a regulatory standpoint.
15 The quality of regulatory oversight and decision-making
16 is greatly appreciated by investors and has been a key
17 component in SCE&G's success in raising funds to finance
18 the new units.

19 I would close by reiterating that filing for
20 updated cost forecasts is fully consistent with our
21 commitment to transparency and candor in reporting on
22 this project. Our goal is to disclose adjustments to
23 our forecasts to this Commission, ORS, and the public in
24 a timely way, and to seek Commission approval of changes
25 in estimates in a timely manner when that is required.

1 In summary, the project is proceeding very
2 successfully. Nuclear generation continues to be of
3 great importance to our system and future benefit to our
4 customers. With escalation, the cost of the project is
5 \$550 million below the estimates which we presented to
6 the Commission in 2008. The \$283 million in adjustments
7 to capital costs presented here reflect reasonable and
8 prudent costs in constructing these units. Given the
9 prudence of the adjustments to costs involved here, I
10 would ask the Commission to approve the updated cost
11 schedules as presented by Ms. Walker.

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22
23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED DIRECT TESTIMONY OF KEVEN B.
25 MARSH FOLLOWS AT PGS 40-71]

DIRECT TESTIMONY

OF

KEVIN B. MARSH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2012-203-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Kevin Marsh and my business address is 220 Operation Way, Cayce, South Carolina. I am Chairman and Chief Executive Officer of SCANA Corporation and South Carolina Electric & Gas Company ("SCE&G" or the "Company").

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I am a graduate, magna cum laude, of the University of Georgia, with a Bachelor of Business Administration degree with a major in accounting. Prior to joining SCE&G, I was employed by the public accounting firm of Deloitte, Haskins & Sells, now known as Deloitte & Touche, L.L.P. I joined SCE&G in 1984 and have served as Controller, Vice President of Corporate Planning, Vice President of Finance, and Treasurer. From 1996 to 2006, I served as Senior Vice President and Chief Financial Officer ("CFO") of SCE&G and SCANA. From 2001-2003, while serving as CFO of SCE&G and SCANA, I also served as

1 President and Chief Operating Officer of PSNC Energy in North Carolina. In May
2 of 2006, I was named President and Chief Operating Officer of SCE&G. In early
3 2011, I was elected President and Chief Operating Officer of SCANA and became
4 Chairman and Chief Executive Officer of SCANA on December 1, 2011.

5 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION IN THE**
6 **PAST?**

7 A. Yes. I have testified in a number of different proceedings.

8 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS**
9 **PROCEEDING?**

10 A. In the petition in this proceeding (the "Petition"), the Company requests
11 that the Public Service Commission of South Carolina (the "Commission")
12 approve updated construction schedules and schedules of forecasted capital costs
13 for the project to construct V. C. Summer Units 2 & 3 (the "Units"). My
14 testimony explains the requests contained in the Petition and places it in the
15 context of the commitments that SCE&G has made to this Commission, the South
16 Carolina Office of Regulatory Staff ("ORS"), the State of South Carolina, its
17 investors and the public concerning how it would approach this project. I also
18 discuss why approving the updated schedules is important to the continued success
19 of the project.

1 **Q. WHAT OTHER WITNESSES ARE PRESENTING DIRECT TESTIMONY**
2 **ON BEHALF OF THE COMPANY?**

3 **A.**The other witnesses presenting direct testimony on behalf of the Company
4 are Mr. Stephen Byrne, Mr. David Lavigne, Mr. Hubert C. ("Clay") Young, III,
5 and Ms. Carlette Walker.

6 1. Mr. Byrne is President for Generation and Transmission and Chief
7 Operating Officer of SCE&G. His testimony updates the Commission and
8 the parties on the current status of the construction of the Units and presents
9 the updated construction schedule for the project. Mr. Byrne also testifies
10 concerning the change orders to the EPC Contract that are reflected in the
11 current cost schedules, and the claims Westinghouse/Shaw has made for
12 recovery of additional costs that it attributes to permitting delays, changing
13 regulatory requirements and unanticipated site conditions.

14 2. Mr. David Lavigne is the General Manager for Operational Readiness
15 within New Nuclear Deployment ("NND") at SCE&G. Mr. Lavigne will
16 testify concerning the current staffing plans and budgets for the NND
17 group, including both the construction management areas, which oversee
18 engineering, licensing and construction of the Units, and the operational
19 readiness and training areas, which hire, train and equip the staffs to operate
20 and maintain the Units once constructed.

1 3. Mr. Young is Manager of Transmission Planning for SCE&G. He testifies
2 concerning the status of the transmission projects associated with the Units
3 and the new cost forecasts for those projects.

4 4. Ms. Walker is Vice President for Nuclear Finance Administration at
5 SCANA. She sponsors the current cost schedules for the project and
6 presents accounting, budgeting and forecasting information supporting the
7 reasonableness and prudence of the adjustments in cost forecasts. Ms.
8 Walker also testifies in further detail concerning key drivers of the changes
9 in the Owners cost forecast.

10 All Company witnesses testify in support of the reasonableness and
11 prudence of the updated cost schedules and the construction costs they represent.
12 All of us have extensive knowledge of the project and have been involved in the
13 ongoing effort to ensure that the project is managed in a prudent, cost-effective
14 and reasonable manner. From my knowledge of the project and my perspective as
15 Chief Executive Officer, it is my firm opinion that the construction schedule and
16 capital cost schedule presented here are prudent and reasonable in every respect
17 and that the project is being managed in a cost-effective and responsible manner.
18 The other witnesses are providing similar testimony about the project from their
19 particular areas of knowledge and expertise.
20

1 **Q. PLEASE PROVIDE AN OVERVIEW OF THE REGULATORY HISTORY**
2 **OF THE PROJECT INCLUDING THE INITIAL BASE LOAD REVIEW**
3 **ACT ("BLRA") PROCEEDINGS CONCERNING THE PROJECT.**

4 **A.** As the Commission is aware, in 2005 SCE&G began to evaluate the
5 alternatives available to meet its customers' growing need for generation resources
6 after 2014. The Company conducted this evaluation in light of its aging fleet of
7 coal generating units, volatile global fossil-fuel markets and the increasingly
8 stringent and costly environmental regulations imposed on fossil-fuel generation,
9 particularly coal generation. In its evaluation, the Company sought proposals
10 from three suppliers of nuclear generation units. The resulting evaluations and the
11 negotiation of an Engineering, Procurement, and Construction Agreement (the
12 "EPC Contract") for the Units took place over the period 2005-2008. On May 23,
13 2008, the Company signed the EPC Contract with Westinghouse Electric
14 Company, and Stone & Webster, which is a part of the Shaw Group
15 ("Westinghouse/Shaw"). Later that month, the Company filed a Combined
16 Application under the BLRA seeking a full regulatory review by the Commission
17 and ORS of the prudence of the project and the reasonableness of the EPC
18 Contract.

19 **Q. WHAT WAS THE BASIS FOR THE INITIAL COST ESTIMATES**
20 **PRESENTED TO THE COMMISSION DURING THAT REVIEW?**

21 **A.** The capital cost schedules that were presented to the Commission on May
22 30, 2008, were based on the construction cost schedules created during negotiation

1 of the EPC Contract as well as forecasts of Owners cost and Transmission costs.
2 SCE&G prepared these forecasts from multiple sources in 2005-2008 to support
3 its comparative evaluation of nuclear technology suppliers. Mr. Lavigne discusses
4 the sources of this information in his testimony. The cost schedules presented to
5 the Commission in 2008 also included a reasonable forecast of owner's
6 contingency for the project.¹ The total forecasted cost of the project was \$4.5
7 billion.

8 **Q. WHAT WAS THE RESULT OF THE 2008-2009 BLRA PROCEEDINGS?**

9 A. These initial cost forecasts for the Units were the subject of extensive
10 discovery and review by expert witnesses for the ORS and others. On March 2,
11 2009, the Commission issued Order No. 2009-104(A) approving those capital cost
12 schedules and associated owner's contingencies. The South Carolina Supreme
13 Court reviewed and upheld the Commission's determinations as to the need for the
14 Units and their prudence finding that "based on the overwhelming amount of
15 evidence in the record, the Commission's determination that SCE&G considered
16 all forms of viable energy generation, and concluded that nuclear energy was the
17 least costly alternative source, is supported by substantial evidence." *Friends of*
18 *Earth v. Pub. Serv. Comm'n*, 387 S.C. 360, 369, 692 S.E.2d 910, 915 (2010). In a
19 related case, *South Carolina Energy Users Comm. v. South Carolina Pub. Serv.*
20 *Comm'n*, 388 S.C. 486, 697 S.E.2d 587 (2010), the Court ruled that costs which

¹ Unless otherwise specified, all cost figures in this testimony are stated in 2007 dollars net of Allowance for Funds Used During Construction and reflect SCE&G's share of the cost of the Units.

1 were not itemized to specific expense items—specifically owner’s contingency
2 costs—could not be included in the Commission-approved cost schedules for the
3 Units. In that opinion, the Court indicated that the BLRA allowed the Company to
4 return to the Commission to seek approval of additional expenditures as
5 circumstances required.

6 **Q. PLEASE DESCRIBE THE UPDATES THAT HAVE OCCURRED TO THE**
7 **COST AND CONSTRUCTION SCHEDULES FOR THE UNITS SINCE**
8 **ORDER NO. 2009-104(A) WAS ISSUED.**

9 **A.** Since Order No. 2009-104(A) was issued in March 2009, SCE&G has
10 come to the Commission twice to update the cost and construction schedules for
11 the Units. In 2009, SCE&G updated the construction schedule and associated cash
12 flow forecasts to reflect Westinghouse/Shaw’s issuance of a site-specific
13 integrated construction schedule for the project. The EPC Contract required
14 Westinghouse/Shaw to begin preparing such a schedule as soon as it was signed.
15 SCE&G presented that schedule to the Commission for review as soon as practical
16 after it was accepted by SCE&G. In the 2009 update filing, the timing of cash
17 flows were adjusted, but the total forecasted cost for the Units of \$4.5 billion in
18 2007 dollars did not change.

19 In 2010, consistent with the decision of the South Carolina Supreme Court
20 in *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm’n*,
21 388 S.C. 486, 697 S.E.2d 587 (2010), the Company removed the owner’s
22 contingency costs from the prior cost forecasts. In addition, in the 2010 update

1 proceeding, the Company identified and itemized approximately \$174 million in
2 costs to specific cost categories for the project that it would have accounted for
3 using owner's contingency costs before the court decision. As a result, in Order
4 No. 2011-345, the Commission approved cost schedules for the project that
5 reduced the approved cost estimate to \$4.3 billion.

6 **Q. PLEASE EXPLAIN THE CAPITAL COST SCHEDULE ADJUSTMENTS**
7 **THAT ARE PRESENTED IN THE PETITION.**

8 A. In this proceeding, SCE&G is presenting updated capital cost forecasts for
9 the Units that identify an additional \$283 million in prudent and necessary costs
10 for the project. There are four categories of costs that comprise this amount:

11 a. On July 11, 2012, SCE&G and Westinghouse/Shaw entered into an
12 agreement to settle claims associated with the delay in issuance of the COL; the
13 redesign of the AP1000 shield building to strengthen it against aircraft impacts;
14 the redesign of certain structural modules to be used in the Units; and the response
15 to unanticipated rock conditions in the Unit 2 foundation area. The settlement of
16 these claims accounts for \$137.5 million of the proposed adjustment to forecasted
17 costs presented here.

18 b. Since 2010, SCE&G has continued to refine and update its forecast
19 of Owners cost related to the project. These updates include updated requirements
20 for staffing the Units based on detailed operations and maintenance planning, new
21 standards emerging in response to the recent Fukushima events, recent guidance
22 from the NRC concerning SCE&G's responsibility as holder of the Combined

1 Operating Licenses ("COL") for the Units, new forecasts of hiring based on
2 training and licensure requirements, and new forecasts of the cost and number of
3 personnel that will be necessary to oversee the safety, quality, and cost of the
4 construction project. In addition, the updates also reflect updated forecasts of the
5 costs of facilities and information technology systems necessary to support the
6 Units when constructed. These updates to Owners cost account for \$131.6 million
7 of the changes to cost forecasts.

8 c. SCE&G has updated the forecasted cost of the transmission projects
9 necessary to route power from the Units onto the grid. These updates are based on
10 additional design and engineering work, updated evaluations of power flows, and
11 more complete information about right-of-way and property requirements.
12 Updates to transmission costs comprise approximately \$7.9 million of the total
13 changes to forecasts.

14 d. Since Order No. 2011-345, three change orders have been negotiated
15 to the EPC Contract. They relate to cyber security, health care costs, and the
16 redesign of certain wastewater piping. These change orders represent
17 approximately \$6 million of the proposed updates.

18 **Q. PLEASE EXPLAIN THE UPDATED CONSTRUCTION SCHEDULE**
19 **THAT IS BEING PRESENTED IN THE PETITION.**

20 A. The construction schedule approved in Order No. 2010-12 was based on the
21 expectation that the COL for the Units would be issued in mid-2011. For various
22 reasons, the license was not issued until March 30, 2012. When the likelihood of

1 delay was recognized, SCE&G and Westinghouse/Shaw began analyzing
2 alternatives for rescheduling the construction plan for the Units and began
3 negotiating Westinghouse/Shaw's claims for a change order under the EPC
4 Contract for the additional costs associated with the delay in COL issuance and
5 related issues. On February 10, 2012, SCE&G instructed Westinghouse/Shaw to
6 proceed under the scenario that delayed the completion date of Unit 2 until March
7 15, 2017, and accelerated the completion date of Unit 3 to May 15, 2018. The
8 proposed construction schedule that is attached to Mr. Byrne's testimony is based
9 on that rescheduling decision.

10 **Q. WHAT IS THE EFFECT OF THESE PROPOSED ADJUSTMENTS?**

11 A. As Ms. Walker testifies, the net effect of these changes is to increase the
12 capital cost schedules for the Units in 2007 dollars from \$4.3 billion, as approved
13 in Order No. 2011-435, to \$4.6 billion. In spite of the increase in costs in 2007
14 dollars, lower escalation rates have reduced SCE&G's total projected cost of the
15 Units in future dollars by \$25 million as compared to the similar projection made
16 at the time of the Order No. 2011-345. The cost of the plant in future dollars,
17 measured using current inflation rates, remains approximately \$5.8 billion as
18 shown on Exhibit 1 to the Petition. This amount is approximately \$500 million
19 less than the cost of the Units in future dollars as presented in the original 2008-
20 2009 BLRA proceedings. At the time of Order No. 2009-104(A), the projected
21 cost of the Units in future dollars was \$6.3 billion.

1 **Q. DOES THE REQUEST FOR BLRA APPROVAL OF THESE UPDATED**
2 **COST SCHEDULES REFLECT PROBLEMS IN THE PROJECT?**

3 A. No. The request for BLRA approval of these updated construction and cost
4 schedules does not reflect any difficulty with the project. We are accelerating the
5 completion date for the project. Based on current escalation rates the cost of the
6 project in future dollars is \$500 million below the original cost estimates. The
7 project is proceeding satisfactorily and the adjustments in construction schedules
8 and cost forecasts that are presented here are a normal and expected part of
9 managing a twelve-year, \$5.8 billion dollar project. In addition, as discussed
10 below, the project has now cleared major licensing, permitting, and procurement
11 hurdles. The work of the past four years has put us in a very good position to
12 complete these Units at a reasonable cost and on a reasonable schedule to meet the
13 needs of our customers.

14 **Q. WHAT WILL THE EFFECT OF THE UNITS BE ON SCE&G'S SYSTEM?**

15 A. In 2019, we plan to have an additional 1,229 MW of efficient and non-
16 emitting nuclear generation on line and serving the people of South Carolina. We
17 project that in 2019, we will have reduced our carbon emissions by 54% compared
18 to their 2005 levels, and 35% compared to their levels in 1995, in large part
19 because of the Units. We also project that in 2019, we will have a system with a
20 very balanced mix of fuel sources: on a capacity basis our generation mix will be
21 27% coal, 28% natural gas, 31% nuclear and 14% hydro/biomass. In 2019, based
22 on how we dispatch our plants, we project that 60% of our energy will come from

1 nuclear and hydro/biomass and only 24% of our energy will be generated using
2 coal. We continue to believe that over the long planning horizon that is involved
3 when procuring base load generation units, the unbalanced reliance on any single
4 fuel source is dangerous from both a cost and a reliability standpoint no matter
5 how cheap or available that fuel may be in the short term.

6 **CURRENT STATUS OF THE NUCLEAR PROJECT**

7 **Q. PLEASE DESCRIBE THE CURRENT STATUS OF THE NUCLEAR**
8 **PROJECT FROM YOUR PERSPECTIVE.**

9 A. During the initial four years of the project, the project team has successfully
10 resolved or mitigated many of the most important challenges that were identified
11 in 2008 as applying to the initial phases of the project. Those challenges include:

- 12 • the challenges associated with initial licensing and permitting for the
13 project;
- 14 • the challenges associated with completing the design of the AP1000 Units;
- 15 • the challenges associated with initial procurement and supply chain
16 management for components and equipment for the Units;
- 17 • the challenges associated with initial site work; and
- 18 • the challenges associated with establishing support in the financial
19 community for the project.

20 In addition, we have carried through on a number of important commitments we
21 made to this Commission, to ORS, to our investors and to the public concerning
22 how we would manage this project and related issues, including our approach to

1 retiring older coal units, to alternative energy sources and to demand side
2 reduction and energy efficiency programs ("DSM").

3 **Q. WHEN THE INITIAL BASE LOAD REVIEW ACT APPLICATION WAS**
4 **FILED IN 2008, WHAT WAS THE SITUATION RELATED TO INITIAL**
5 **LICENSING AND PERMITTING?**

6 A. When the initial BLRA application was filed, the Nuclear Regulatory
7 Commission ("NRC") was in the early stages of reviewing the 1,500 page COL
8 application for the Units. The NRC was also in the early stages of reviewing the
9 reference plant COL application that provided the vehicle for NRC licensing of the
10 standard AP1000 plant configuration. Furthermore, in separate proceedings the
11 NRC was considering revisions to certain aspects of the AP1000 reactor design to
12 strengthen its resistance to aircraft impacts, and to address other design issues and
13 make other improvements. At that time, the environmental report and wetlands
14 permit applications for the project were also in their initial stages of review by the
15 United States Army Corps of Engineers and related agencies including the United
16 States Environmental Protection Agency and the United States Fish and Wildlife
17 Service.

18 **Q. WHAT RISKS OR CHALLENGES DID LICENSING AND PERMITTING**
19 **POSE FOR THE PROJECT?**

20 A. The 2008 BLRA application stated that "the risks related to the COLA
21 process include the fact that many of the NRC regulations, standards and
22 processes under which the licensing of the Units will take place are new and

1 relatively untested; NRC staffing to support the new round of nuclear licensing is
2 still being assembled; and many of the personnel that will be involved in this
3 licensing process have not been part of the licensing of new nuclear units at any
4 other time in their careers.” BLRA Application, Docket No. 2008-196-E, Exhibit
5 J, p. 3. In addition, SCE&G stated that while it did not believe that it was likely
6 that the licensing process would uncover material issues related to the Units, “the
7 emergence of substantive design-related or process-related issues are not beyond
8 possibility.” Id. at p. 12. In this regard, SCE&G identified that one of the most
9 significant risks to the project was “the risk of delay in the issuance of a COL, the
10 resulting disruption in the construction schedule, and the increase in costs that
11 such a delay would represent.” Id.

12 **Q. WHAT DID SCE&G COMMIT TO DO ABOUT THESE CHALLENGES?**

13 A. SCE&G committed itself to actively oversee and monitor these licensing
14 and permitting efforts, and to intervene where necessary to ensure that they were
15 conducted in a timely and professional manner. SCE&G specifically committed to
16 the Commission that it would resolve these licensing and permitting issues and
17 obtain the COL within the 18 month scheduling contingency that the Commission
18 approved in Order No. 2009-104(A).

19 **Q. WHAT WAS THE RESULT?**

20 A. Over the past four years, working with Westinghouse/Shaw and other
21 members of the industry, we have overcome the challenges posed by the initial
22 licensing and permitting of the Units and completing their design. As of June

1 2012, the major licenses, permits, and environmental certifications for the
2 construction and operations of the Units are now in hand or forthcoming. These
3 permits and licenses include:

- 4 1. The Design Control Document ("DCD") amendments for the
5 AP1000 design through DCD-19.
- 6 2. The reference plant COL for the AP1000 reactor.
- 7 3. The site specific COL for the Units themselves.
- 8 4. The Finding of No Significant Environmental Impact related to the
9 construction and operations for the Units as required under the
10 National Environmental Policy Act ("NEPA").
- 11 5. The Clean Water Act Section 401 certification for the project as to
12 its ability to operate in compliance with federal Clean Water Act
13 requirements.
- 14 6. The Clean Water Act Section 404 permit required for certain work
15 on intermittent stream banks on site that qualify as federally
16 protected wetlands.
- 17 7. FERC permits for cooling water withdrawals, construction of
18 withdrawal structures within FERC project boundaries and related
19 construction work.
- 20 8. The National Pollution Discharge Elimination System ("NPDES")
21 permits for discharges of blow-down water from the cooling towers

1 and other waste water discharges, which is in the final stages of
2 review and is expected shortly.

3 The completion of the initial licensing, permitting and design work for the Units
4 represents the completion of a group of major milestones for the project. A major
5 risk factor that was identified in 2008 has now been resolved.

6 **Q. IN OBTAINING THESE LICENSES AND PERMITS DID YOU MEET**
7 **YOUR COMMITMENTS AS TO SCHEDULING?**

8 A. Yes. We have met our specific commitment to have the initial licensing
9 and permitting issues for the Units resolved within the 18 month schedule
10 contingency approved by the Commission in Order No. 2009-104(A). However,
11 for reasons that Mr. Byrne will explain, the COL was issued approximately nine
12 months later than what we anticipated when we formulated our construction
13 schedules and cash flow projections. To account for this fact, and to increase the
14 efficiency of the construction program going forward, we have reached an
15 agreement with Westinghouse/Shaw to delay the substantial completion date for
16 Unit 2 by 11 and one-half months, from April 1, 2016, to March 15, 2017, and
17 accelerate the substantial completion date for Unit 3 by seven and one-half months
18 to May 15, 2018. As Mr. Byrne will testify, this sequencing of the construction of
19 the two Units creates construction efficiencies that will mitigate some of the
20 additional costs of the licensing delay and related design changes by \$15.9 million.
21 The cost and construction schedules presented in this proceeding reflect those
22 substantial completion dates.

1 **Q. WILL THERE BE ADDITIONAL COSTS ASSOCIATED WITH THESE**
2 **SCHEDULE CHANGES?**

3 A. Yes, as I mentioned above, there will be additional costs associated with
4 these schedule changes, as well as the design changes that arose out of the
5 licensing review. As mentioned above, we have negotiated agreements with
6 Westinghouse/Shaw as to the amount of those additional costs under the EPC
7 Contract.

8 **Q. SINCE 2008, WHAT COMMITMENTS HAS SCE&G MADE**
9 **CONCERNING ITS APPROACH TO THE ADMINISTRATION OF THE**
10 **EPC CONTRACT?**

11 A. SCE&G has consistently operated under a commitment to the Commission,
12 ORS and the public to use the provisions of the EPC Contract to manage and
13 control construction costs and to ensure the safety, quality and timeliness of the
14 construction project.

15 **Q. WHAT HAVE YOU DONE TO FOLLOW THROUGH ON THIS**
16 **COMMITMENT?**

17 A. In negotiating the EPC Contract, we persuaded Westinghouse/Shaw to
18 accept more than 50% of the EPC Contract work being assigned to Fixed/Firm
19 cost categories, which are the categories under which Westinghouse/Shaw bears
20 the principal price risk. In 2010, we persuaded Westinghouse/Shaw to shift an
21 additional \$315 million in EPC costs to Firm/Fixed categories. At that point,
22 approximately two-thirds of the EPC Contract costs were in Fixed/Firm

1 categories. As of end of the second quarter of 2012, only a little more than one-
2 fourth of the total EPC Contract costs remains to be spent in categories that are not
3 subject to Fixed/Firm pricing limitations.

4 Limiting price risk is a major benefit in itself. But of equal importance is
5 how shifting price risks to Westinghouse/Shaw improves SCE&G's ability to
6 administer the project effectively. For scopes of work where Westinghouse/Shaw
7 bears price risk, the NND teams review invoices for milestone completion, and for
8 proper coding, accounting and allocation of costs. For these scopes of work, there
9 is no need for our NND teams to audit cost data in the same detail as where the
10 EPC Contract provides for Firm or Indexed pricing. Work load is reduced and
11 opportunities for price disputes are reduced or eliminated. Shifting price risk to
12 Westinghouse/Shaw allows SCE&G's personnel to focus on the safety, quality
13 and timeliness of the work done.

14 **Q. WHAT IS SCE&G'S APPROACH WHERE IT DOES BEAR THE PRICE**
15 **RISK?**

16 **A.** Where SCE&G does bear the price risk, we have put in place very
17 experienced and determined teams that audit Westinghouse/Shaw invoices and
18 work practices carefully, identify invoicing problems and contest costs where
19 there is a basis for doing so. Our oversight teams carefully manage the change
20 order process for the benefit of the Company and its customers.

21 To date, apart from the Change Order No. 16 related to COL delay costs,
22 and the Change Order No. 8 which shifted \$315 million to Fixed/Firm pricing,

1 there have been eight change orders involving substantive changes to costs and
2 scopes of work under the EPC Contract. These eight change orders total \$7.5
3 million or less than one-quarter of one percent of the project's cost forecast.

4 **Q. PLEASE DISCUSS HOW THE RESOLUTION OF THE COL DELAY**
5 **CLAIMS AND RELATED CLAIMS REFLECTS THE COMPANY'S**
6 **COMMITMENTS TO EFFECTIVELY MANAGE THE EPC CONTRACT**
7 **FOR THE BENEFIT OF THE PROJECT.**

8 A. As mentioned above, on July 11, 2012, SCE&G and Westinghouse/Shaw
9 entered into an agreement to adopt a new construction schedule for the Units and
10 to resolve claims related to the COL delay and other matters. The resulting
11 adjustment to EPC Contract cost was \$137.5 million or \$76.1 million less than
12 Westinghouse/Shaw's initial cost analysis. This timely and comprehensive
13 resolution of these matters occurred in part because during the period 2011-2012,
14 SCE&G pushed Westinghouse/Shaw both to create an effective construction plan
15 to respond to the delay and to quantify and substantiate any claims they might
16 have for compensation related to that delay and to design and licensing issues. We
17 put a great deal of pressure on Westinghouse/Shaw to negotiate a resolution of
18 these claims quickly and in good faith for the benefit of the project. We made it
19 clear that it was our expectation that these claims would be resolved before a full
20 notice to proceed was given to move forward with the work.

1 **Q. WHAT IS THE RESULT OF HAVING DONE SO?**

2 A. As Mr. Byrne will testify, we believe that the resulting agreement, standing
3 alone, is a prudent and fair resolution of these claims. But in addition, by
4 resolving these issues quickly and without litigation we have eliminated from the
5 project the threat of a divisive and distracting lawsuit between the principals at this
6 critical stage in the project. Because we were successful in these negotiations,
7 SCE&G was able to give Westinghouse/Shaw full notice to proceed with
8 construction when the COL was issued without the threat of a protracted lawsuit
9 hanging over the project. We are able to go forward with one objective, which is
10 building two safe, reliable nuclear Units that will provide the people of this State
11 with a reasonably priced, non-emitting source of baseload power for generations to
12 come.

13 **Q. WERE YOU ABLE TO MEET YOUR COMMITMENT TO HAVE THE**
14 **SITE PREPARATION WORK READY TO PLACE THE FIRST**
15 **NUCLEAR SAFETY CONCRETE WHEN THE COL WAS ISSUED?**

16 A. One of our principal goals in this phase of the project has been to ensure
17 that the initial development plan for the Jenkinsville site was substantially
18 completed in time to support the placement of nuclear safety-related concrete as
19 soon as the COL was issued. Through the diligence of our teams and
20 Westinghouse/Shaw, we were able to complete initial site work, in which 11
21 million cubic yards of earth were moved, a railroad was relocated, nearly 10 miles
22 of construction roads and a heavy haul bridge were constructed or paved, 21 miles

1 of pipe were laid, two high volume concrete batch plants were built and put into
2 operation, and supporting structures and facilities with 680,000 square feet under
3 roof were constructed. In all, 5.4 million man hours of work have been done on
4 the site since 2008 with an admirable safety record. We placed the first nuclear
5 safety-related concrete on Tuesday April 3, 2012, the second business day after the
6 COL was issued.

7 **Q. WHERE WAS THE FIRST NUCLEAR SAFETY-RELATED CONCRETE**
8 **PLACED?**

9 A. The first nuclear safety-related concrete that was placed for the Units was
10 the dental, leveling and mud mat concrete in the basement area of Unit 2.
11 Westinghouse/Shaw had planned to place this concrete before the COL was
12 issued, but learned early in the project that this was considered work that could not
13 proceed until the COL was issued.

14 **Q. WHAT DID YOU SAY IN 2008 ABOUT THE CHALLENGE OF**
15 **REESTABLISHING AN ACTIVE NUCLEAR SUPPLY CHAIN THAT**
16 **MEETS EXACTING NUCLEAR SAFETY STANDARDS?**

17 A. In the 2008 BLRA proceedings, we identified reestablishing an effective
18 supply chain for nuclear construction as a major challenge for the project, which
19 requires a supply chain that is able to do high-quality, timely work under the
20 exacting quality assurance and quality control ("QA/QC") standards that apply to
21 nuclear-safety related construction. We said:

1 *The supply chain for nuclear-grade plant components has not*
2 *been supported by new construction for some decades and will need*
3 *to be significantly expanded to meet the requirements of this new*
4 *construction cycle. . . . Quality controls and manufacturing*
5 *standards for components for nuclear plants are very stringent and*
6 *the processes involved may place unique demands on component*
7 *manufacturers. It is possible that manufacturers of unique*
8 *components (e.g., steam generators and pump assemblies or other*
9 *large components or modules used in the Units) and manufacturers*
10 *of other sensitive components may encounter problems with their*
11 *manufacturing processes or in meeting quality control standards.*

12 BLRA Application, Docket No. 2008-196-E, at Exhibit J.

13 **Q. HAVE YOU BEEN ABLE TO MEET THIS CHALLENGE?**

14 A. SCE&G has devoted a great deal of time and attention in resolving QA/QC
15 issues. Beginning in 2008, we assembled a team of capable and skilled experts in
16 QA/QC oversight. Along with their counterparts at Westinghouse/Shaw, they
17 have reviewed QA/QC programs for suppliers in all parts of this project's supply
18 chain. The members of the SCE&G team have conducted on-site inspections and
19 have called suppliers and Westinghouse/Shaw to account when issues have arisen.
20 They have assisted suppliers in resolving QA/QC issues. As a result of their
21 efforts, and with SCE&G's active involvement, QA/QC problems have been

1 identified early in the project and for the present at least appear largely to be
2 resolved.

3 **Q. PLEASE ELABORATE.**

4 A. Presently, all major equipment procurements have been placed. Suppliers'
5 QA/QC programs appear to be functioning as intended, and by all indications the
6 fabrication of components for the Units appears to be progressing well in factories
7 around the world. With the exception of a limited number of components for Unit
8 3, all major equipment and components for the Units are either in production or
9 fabrication of them is finished. We intend to maintain a high level of vigilance on
10 these suppliers and the quality of their work. Part of the reason we are seeking to
11 increase staffing and associated cost projections is to allow us to do so.

12 **Q. WHAT ABOUT QA/QC AT SHAW MODULAR SOLUTIONS?**

13 A. Our most significant area of concern involves the module fabrication efforts
14 by Shaw Modular Solutions ("SMS") at its facility in Lake Charles, Louisiana.
15 We have monitored the work at SMS very closely for some time and will continue
16 to do so. In fact, we have a resident inspector at this facility on a full-time basis.
17 We believe that SMS has made significant strides in adopting a nuclear safety
18 culture at this facility. However, we continue to monitor SMS's work very closely
19 and SMS's ability to meet the fabrication schedules required.

20 I cannot leave this topic without mentioning my appreciation for the work
21 of our NND construction oversight and financial oversight teams. They are

1 among the most experienced, motivated and capable teams in our Company. They
2 are doing an exceptional job in overseeing the costs and quality of the project.

3 **Q. WHAT COMMITMENTS DID SCE&G MAKE IN THE 2008 BLRA**
4 **PROCEEDINGS CONCERNING DSM AND CONSERVATION**
5 **PROGRAMS?**

6 A. In its original BLRA application, SCE&G recognized the importance of
7 reviewing and reinvigorating its DSM programs in light of growing societal
8 interest and receptivity to them. In the 2008 proceeding, SCE&G made the
9 commitment to have outside consultants with national standing conduct a
10 comprehensive review of potential DSM programs for SCE&G and to bring the
11 resulting recommendations back to the Commission for approval and
12 implementation. SCE&G did so and in Order No. 2010-472 the Commission
13 approved an initial suite of nine cost-justified DSM programs for SCE&G which
14 included programs and measures to reach all customer classes.

15 **Q. WHAT HAS BEEN THE RESULT?**

16 A. SCE&G has completed the review and analysis of the first full year of
17 implementation of its current DSM program. During the 2011 program year,
18 SCE&G invested \$11 million in DSM programs and the Company reduced system
19 demands by approximately 10 MW. One of the largest single programs has been
20 our Home Energy Report program. Approximately 28,000 customers have
21 participated in this program. However, the program with the greatest impact on
22 customers' demands has been our program to place discounted high-efficiency

1 lighting fixtures and bulbs on the shelves of local retailers. This program has
2 assisted in the sales of over 1.2 million discounted high-efficiency light bulbs in
3 our service territory since it was initiated.

4 **Q. IN THE 2008 BLRA PROCEEDINGS WHAT DID SCE&G SAY ABOUT**
5 **THE POSSIBILITY OF RETIRING OLDER COAL UNITS?**

6 A. In the 2008 BLRA hearings, we indicated that building nuclear generation
7 gives us flexibility in our generation's plans to consider retiring older coal
8 generation units. We committed to review SCE&G's system resource
9 requirements to determine if it were possible to retire older coal fired generation
10 units in future years.

11 **Q. WHAT HAS BEEN THE RESULT?**

12 A. As a result of increasingly stringent environmental regulations, lower than
13 forecasted rates of growth in electric demand, the effects of DSM programs, and
14 the prospective availability of new nuclear base load generation, SCE&G has
15 made the decision that it will retire from service the 90 MW Canadys 1 coal-fired
16 unit, and will switch the 95 MW Urquhart 3 coal-fired unit to gas-fired operation
17 only. In addition, SCE&G's current base-case Integrated Resource Plan ("IRP")
18 calls for four additional coal-fired units to be retired in 2017-2018 when Units 2
19 and 3 enter commercial service. While these plans are subject to ongoing review
20 and revision, it is our present intention to retire 730 MW of older coal-fired
21 capacity by the end of 2018.

1 **Q. CAN YOU COMMIT TO THESE RETIREMENTS TODAY?**

2 A. No. Our first priority is to serve our customers safely, reliably and
3 efficiently. If our customers need power from these units in future years, and if
4 we can use them for some additional time within the established environmental
5 regulations, we should have the flexibility to do so. Given what we know today,
6 our intent is to retire these units within the time frames indicated. But it would not
7 be in the best interest of customers or the state to paint us into a corner with
8 binding commitments as to the timing of these retirements.

9 **Q. PLEASE DISCUSS SCE&G'S COMMITMENTS CONCERNING ITS**
10 **RECEPTIVITY TO ALTERNATIVE GENERATION WHERE**
11 **PRACTICAL AND COST JUSTIFIED.**

12 A. In the 2008 BLRA hearings, we testified that the decision to build the Units
13 notwithstanding, SCE&G would not minimize the potential that alternative energy
14 might serve as a supplemental source of generation when practical and cost
15 justified.

16 **Q. WHAT HAS HAPPENED IN THIS REGARD?**

17 A. In 2011, SCE&G installed the largest thin laminate solar generation system
18 in the Southeast, and the sixth largest such system in the nation. The installation
19 covers 10 acres of rooftop at Boeing's North Charleston production facility and at
20 peak capacity generates 2.6 MW or enough power to serve 250 average homes on
21 SCE&G's system. The installation is expected to generate approximately 3,500
22 MWH per year. In addition, in 2011 SCE&G generated 336,604 MWH in

1 renewable energy using biomass fuels at its North Charleston facility located at the
2 KapStone Charleston Kraft, LLC plant. In partnership with SCE&G, Duke,
3 Progress, ORS and the South Carolina Energy Office, created Palmetto Clean
4 Energy ("PaCE") to provide customers a voluntary program to promote the
5 development of renewable energy resources. Launched in 2008, PaCE uses funds
6 collected voluntarily from customers to pay renewable generators a supplemental
7 financial incentive for producing renewable energy. Currently, 150 customers
8 own renewable generation and participate in SCE&G's net metering programs.
9 This customer-owned generation (solar, wind and biomass) offsets energy
10 purchased from the grid, uses the grid to store excess energy produced or sells all
11 energy produced to SCE&G at a small producer power rate.

12 **Q. PLEASE DISCUSS SCE&G'S COMMITMENT TO ENSURE THE**
13 **CONTINUED SUPPORT OF THE INVESTMENT COMMUNITY FOR**
14 **THIS PROJECT.**

15 A. During 2008, SCE&G committed to use the tools at its disposal to raise the
16 funds required for this project on reasonable terms and to ensure that the
17 investment community remained supportive of the project and the Company's
18 access to capital in general.

19 **Q. WHAT HAS BEEN THE RESULT?**

20 A. As of the end of the second quarter of 2012, SCE&G will have successfully
21 financed the investment of approximately \$1.5 billion in capital in construction of
22 the Units. That represents approximately 26% of the current cost forecast of \$5.8

1 billion. We have done so while maintaining a solid investment-grade credit
2 rating, the support of the investment community for the Company's financial
3 plans and strategic direction, and the Company's ability to raise capital for this
4 project and other needs of its system on reasonable terms. Our last two bond
5 financings have been at some of the lowest interest rates in the history of the
6 electric utility industry. These low rates benefit our customers directly since
7 lower costs of debt translate directly into lower rates under the BLRA and under
8 general rate making principles.

9 **Q. HOW HAS THIS BEEN ACCOMPLISHED?**

10 A. As promised in 2008, SCE&G has been guided by values of transparency
11 and candor in our dealing with regulators and the public in this matter. Under the
12 oversight of the Commission and ORS, we have implemented a quarterly reporting
13 process that sets the standard nationwide for reporting on utility construction
14 projects. As I have mentioned in past testimony, we have been told repeatedly by
15 analysts who follow this industry closely that no utility construction project
16 anywhere in the nation provides a higher level of public disclosure and regulatory
17 transparency than is being provided for this project. In addition, we have come to
18 the Commission regularly to update cost projection and construction schedules as
19 circumstances warrant.

20 **Q. WHAT ROLE DOES REGULATION PLAY IN THIS?**

21 A. The project could not be where it is today without the tough but consistent
22 and fair-minded regulatory oversight we have received from the Commission and

1 ORS. We understand our responsibility as a company is to manage the project
2 prudently and to bring our issues and challenges to the Commission and ORS in a
3 candid and transparent way. We appreciate the accountability that regulatory
4 oversight provides. For its part, the investment community is very comfortable
5 with the consistency and predictability of our annual revised rates filings and
6 update filings and with the way that this project is being managed from a
7 regulatory standpoint. With continued reasonable decision-making by the
8 Commission and ORS, and reasonable market conditions, we do not see any
9 reason to doubt our ability to continue to manage the financial requirements of this
10 project.

11 **Q. HOW DOES FILING FOR UPDATED COST FORECASTS IN THIS**
12 **PROCEEDING FIT WITHIN THESE COMMITMENTS?**

13 A. Filing for updated cost forecasts is fully consistent with our commitment to
14 transparency and candor. Our goal is to disclose adjustments to our forecasts to
15 the Commission, ORS and the public as they become known and to seek
16 Commission approval of changes in estimates in a timely manner when that is
17 required. The present request is part of that approach.

18 **Q. ARE ANY OF THE ADJUSTMENTS IN COSTS REFLECTED HERE THE**
19 **RESULT OF IMPRUDENCE BY THE COMPANY?**

20 A. No. To the contrary, these costs reflect reasonable and prudent costs of
21 constructing these Units. They are the result of continuing to refine cost forecasts

1 as the project evolves and to surface and resolve cost issues under the EPC
2 Contract as they arise.

3 **Q. DOES SCE&G EXPECT TO COME TO THE COMMISSION WITH**
4 **FURTHER ADJUSTMENTS TO THE COSTS AND SCHEDULES OF THE**
5 **UNITS IN THE FUTURE?**

6 A. We are putting before the Commission the changes we know to be
7 necessary at this time. We do not know whether further adjustments in the costs
8 and schedules for the Units will be needed in the future. However, we would
9 point out that we are approximately six years into a 12 year project.

- 10 • As to permitting and design, the standard plant design for the Units is
11 essentially complete. The COL and other major construction and operation
12 licenses and permits are now in hand.
- 13 • As to the EPC Contract, the additional costs related to initial design
14 improvements and initial licensing have been quantified and agreed to. Full
15 notice to proceed has been given to Westinghouse/Shaw. Westinghouse/Shaw
16 bears the principal price risk for the majority of what remains to be spent under
17 the EPC Contract.
- 18 • As to the initial procurement, fabrication, and construction work on the project,
19 the initial procurement of the major equipment for the Units is complete. With
20 limited exceptions fabrication is going well. The initial site work and
21 excavation work on site are complete. Nuclear safety related construction
22 work has begun.

- 1 • As to Owners cost and Transmission cost, SCE&G has detailed training and
2 staffing plans in hand for the Units. We have now conducted a thorough
3 review of those staffing plans. The routing for most of our transmission
4 projects is done. Substation sites and rights-of-way for much of the
5 transmission work have been obtained and the final siting proceedings are
6 underway before the Commission.

7 We continuously review and update our project plans and forecasts as does
8 Westinghouse/Shaw. No project of this magnitude is static from either a cost or a
9 schedule standpoint. With such a project, the question is not whether you will
10 encounter challenges, but whether you have the leadership team, experience and
11 attitude to respond to the inevitable challenges effectively. The financial markets
12 have consistently supported this project because they have seen how the SCE&G
13 teams, with appropriate support and accountability from the Commission and
14 ORS, have responded to the challenges that have arisen in this project. As we
15 begin nuclear-safety related work on site, risks will shift from licensing, design,
16 and procurement, to shipping logistics, on-site construction and start-up and
17 acceptance testing. Changes in cost forecasts or construction schedules may well
18 be required in the future. But the work we have done to date has put us in a
19 position where we are confident of our ability to meet challenges in the future.

20 **Q. WHAT ARE YOU ASKING THE COMMISSION TO DO?**

21 **A.** SCE&G is asking the Commission to approve the updated cost forecasts
22 and construction schedules for the Units as presented in the petition in this matter

1 and in the testimony of Mr. Byrne, Ms. Walker and other witnesses. SCE&G
2 requests that the Commission find that the changes in cost and construction
3 schedules are the result of normal and expected changes in a project of this size
4 and complexity, and have not been shown by any party to be the result of
5 imprudence by the Company.

6 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

7 **A. Yes. It does.**

1 BY MR. BURGESS:

2 Q Mr. Marsh, have you also prepared a summary of your
3 rebuttal testimony?

4 A Yes, I have.

5 Q Could you also deliver that at this time?

6 A My rebuttal testimony points out certain difficulties
7 relating to the testimony of the Sierra Club's witness,
8 Dr. Mark Cooper. Specifically, Dr. Cooper seems to
9 substitute a simplistic modeling exercise, principally
10 driven by low natural-gas prices, for the complex,
11 multi-scenario analysis that SCE&G performed in choosing
12 to construct the units.

13 As Dr. Lynch testifies on where we stand today, the
14 lower cost of completing the units more than offsets the
15 effects of lower gas prices. However, the decision to
16 build nuclear was not based on a single fuel-cost
17 comparison; it was based on the recognition that new
18 nuclear creates a balanced generation system that can
19 function effectively in a number of different
20 combinations of fuel prices, environmental restrictions,
21 supply restrictions, and pipeline capacity restrictions.
22 A system that relies on coal and natural gas for over
23 two-thirds of its energy does not have the same
24 flexibility.

25 In the initial BLRA proceeding, SCE&G provided a

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1 complex and multidimensional analysis of the risk and
2 cost of various generating alternatives that are
3 reasonably able to meet SCE&G's requirements for base-
4 load generation resources. Dr. Lynch and his team
5 evaluated these alternatives over a four-year planning
6 horizon and across multiple scenarios, including
7 different assumptions as to fuel cost and environmental
8 regulations, and other factors.

9 SCE&G's decision to build nuclear generation was
10 not based on any single scenario related to fuel cost or
11 environmental regulations. The decision was made
12 because an analysis across a multiple -- across multiple
13 scenarios and a significant block of reliable, non-
14 emitting nuclear generation helps reduce our customers'
15 exposure to risk related to the prices, availability,
16 and environmental cost imposed on nuclear fuel. Without
17 new nuclear capacity, our generation system would be
18 forced to rely on fossil fuels for more than 70 percent
19 of its energy in 2019. With new nuclear, our generation
20 mix in 2019 will be 27 percent coal, 28 percent natural
21 gas, 31 percent nuclear, and 14 percent hydro and
22 biomass. We will have reduced our carbon emissions by
23 54 percent compared to their levels in 2005, giving us a
24 secure position if carbon taxes, cap-and-trade systems,
25 or other regulatory mechanisms impose costs on carbon

1 emissions. Our balanced generation portfolio will also
2 mean that, as we go forward from 2019, we'd have the
3 option to add additional natural-gas-fired generation to
4 our system without fear of becoming overly reliant on
5 natural gas as a fuel. We can also add resources like
6 solar, wind, or DSM where feasible, knowing that
7 standing behind them is a secure foundation of reliable,
8 base-load generation. More than 660,000 customers
9 depend on SCE&G to make decisions that result in
10 reliable, efficient electric service, regarding future
11 environmental regulations of fossil-fuel markets. A
12 diverse portfolio of plants creates a generation system
13 that's able to perform well in multiple contexts and to
14 respond to the inherent volatility in fuel prices, fuel
15 supply, and transportation issues, operational
16 conditions, and environmental regulation. This is the
17 reason why SCE&G chose to add nuclear generation in
18 2008. Nothing in Dr. Cooper's analysis calls that
19 conclusion into question.

20 Completing the nuclear units is the best course for
21 SCE&G to take, for all the reasons stated above.

22
23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED REBUTTAL TESTIMONY OF KEVIN B.
25 MARSH FOLLOWS AT PGS 75-89]

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PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1 **REBUTTAL TESTIMONY**
2 **OF**
3 **KEVIN B. MARSH**
4 **ON BEHALF OF**
5 **SOUTH CAROLINA ELECTRIC & GAS COMPANY**
6 **DOCKET NO. 2012-203-E**
7

8 **Q. PLEASE STATE YOUR NAME AND OCCUPATION.**

9 A. My name is Kevin Marsh and I am Chairman and Chief Executive
10 Officer of SCANA Corporation and South Carolina Electric & Gas
11 Company ("SCE&G" or the "Company").

12 **Q. ARE YOU THE SAME KEVIN MARSH WHO IS PROVIDING**
13 **DIRECT TESTIMONY IN THIS PROCEEDING?**

14 A. I am.

15 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN**
16 **THIS PROCEEDING?**

17 A. My testimony points out problems and inconsistencies in the
18 positions asserted by the Sierra Club through the testimony of its witness
19 Dr. Cooper. My testimony points out how the position taken by the Sierra
20 Club here is different from its position in other contexts.

21 **Q. PLEASE SUMMARIZE THE SIERRA CLUB'S POSITION IN THIS**
22 **PROCEEDING.**

1 A. The Sierra Club's position is that the Commission should use this
2 proceeding to order the Company to abandon its new nuclear construction
3 program, pass billions of dollars in abandonment costs onto customers, and
4 rely on additional natural gas generation, supplemented by alternative
5 energy and conservation programs, to meet the needs of its customers and
6 the state going forward.

7 **Q. WHAT IS THE COMPANY'S POSITION CONCERNING THE**
8 **PROPRIETY OF RAISING THESE ISSUES IN THIS**
9 **PROCEEDING?**

10 A. The Company's position is that this proceeding is limited to the
11 review of the prudence of the specific changes in capital cost forecasts and
12 construction schedules that the Company has placed before the
13 Commission for approval, pursuant to S.C. Code Ann. § 58-33-270(E).

14 **Q. YOU MENTIONED THAT DR. COOPER'S POSITION IN THIS**
15 **PROCEEDING IS DIFFERENT FROM THAT OF THE SIERRA**
16 **CLUB IN OTHER CONTEXTS. WHAT IS THE SIERRA CLUB'S**
17 **POSITION ON NATURAL GAS AS AN ENERGY SOURCE**
18 **OUTSIDE OF THIS PROCEEDING?**

19 A. Dr. Cooper's suggestion that SCE&G and this Commission should
20 rely on the potential future availability of abundant, low-cost natural gas
21 generation as an alternative to nuclear generation contradicts the position
22 that the Sierra Club takes outside of this proceeding. In May of this year,

1 the Sierra Club launched its "Beyond Natural Gas" campaign. At the press
 2 conference announcing the launch, the Sierra Club's executive director said
 3 the following:

4 *As we push to retire coal plants, we're going to work to make*
 5 *sure we're not simultaneously switching to natural-gas*
 6 *infrastructure. And we're going to be preventing new gas*
 7 *plants from being built wherever we can.¹*

8 The "Beyond Natural Gas" page on the Sierra Club Website contains
 9 the following message from the Sierra Club's President:

10 *Fossil fuels have no part in America's energy future—coal,*
 11 *oil and natural gas are literally poisoning us. The emergence*
 12 *of natural gas as a significant part of our energy mix is*
 13 *particularly frightening because it dangerously postpones*
 14 *investment in clean energy at a time when we should be*
 15 *doubling down on wind, solar and energy efficiency.²*

16 The Sierra Club's official energy policy documents state that:

17 *The Sierra Club's goal is to develop and use as little*
 18 *natural gas as possible and to wean ourselves from most*
 19 *fossil fuels, including natural gas, as swiftly as possible and*
 20 *by no later than 2050.³*

21 **Q. HOW DO YOU RESPOND TO THE SUBSTANCE OF THE SIERRA**
 22 **CLUB'S POSITION IN THIS PROCEEDING?**

23 **A.** Dr. Cooper recommends that SCE&G be ordered to rely primarily
 24 on natural gas-fired generation for its future needs. But contrary to his

¹ Amy Harder, *War Over Natural Gas About to Explode, Sierra Club launches 'Beyond Gas' Campaign*, NATIONAL JOURNAL, (MAY 3, 2012, 2:03 PM), <http://www.nationaljournal.com/energy-report/war-over-natural-gas-about-to-escalate-20120503> (last visited August 23, 2012).

² *Beyond Natural Gas*, SIERRA CLUB, <http://content.sierraclub.org/naturalgas> (last visited August 23, 2012).

³ *Energy Resources Policy*, SIERRA CLUB, 18, <http://www.sierraclub.org/policy/conservation/energy.pdf>, (last visited August 23, 2012) (adopted by the Sierra Club Board of Directors on September 16, 2006 and last amended on July 25, 2011).

1 recommendation, his client, the Sierra Club, is raising money and rallying
2 public and political support for a program to prevent the development and
3 use of natural gas and to make natural gas production and use as difficult as
4 possible. The Sierra Club's anti-natural gas position points out the
5 uncertainties that remain as to whether natural gas fired generation will in
6 fact be available at the costs and in the quantities that Dr. Cooper assumes.
7 If the Commission were to accept Dr. Cooper's recommendation, then in
8 2019, SCE&G's customers would be relying on a generating system that
9 generates 47% of its electricity from natural gas, which the Sierra Club
10 opposes, and 76% from fossil fuels, which they also oppose. Beyond these
11 inconsistencies, Dr. Cooper and the Sierra Club fundamentally
12 misunderstand the nature of resource planning by utilities and the specific
13 reasons that SCE&G chose to build the Units. Dr. Cooper also
14 misconstrues the purpose and intent of the Base Load Review Act
15 ("BLRA"), which was intended to prevent just this sort of ex post facto
16 review of the decisions to construct nuclear generation.

17 **Q. WHY DID SCE&G DECIDE TO BUILD THE NUCLEAR UNITS AT**
18 **ISSUE HERE?**

19 **A.** In the 2008 BLRA proceedings and thereafter, SCE&G has been
20 very clear that its goal in choosing nuclear capacity was to create a
21 balanced generation system with diverse fuel sources, one that can respond

1 effectively to uncertain future conditions and is not unduly dependent on
2 volatile fossil fuel markets. As I testified in December of 2008:

3 *Building nuclear capacity diversifies SCE&G's*
4 *exposure to increasingly volatile and globalized fossil fuel*
5 *markets as well as risks related to the future environmental*
6 *costs associated with CO₂ emissions. The price and*
7 *environmental risks related to fossil fuels are among the most*
8 *serious risks that SCE&G and its electric customers face.*
9 *Adding more gas or coal capacity to meet base load needs in*
10 *the 2016-2019 period would increase SCE&G's exposure to*
11 *those risks. As Dr. Lynch's testimony indicates, if SCE&G*
12 *were to meet its 2016-2019 capacity needs with natural gas,*
13 *its generation mix would be 79% fossil fuel based in 2020.*

14 *On the other hand, by building new nuclear*
15 *generation, SCE&G will reduce exposure to those risks. The*
16 *Company will pay capital costs which, although significant,*
17 *are largely defined today in the EPC Contract, and will be*
18 *fully quantified when construction is complete.*
19

20 Transcript of Hearing, Docket No. 2008-196-E ("TR.") at 170-71. I further
21 testified:

22 *As to combined-cycle gas generation, SCE&G's exposure to*
23 *increasingly volatile and globalized fossil-fuel markets, as*
24 *well as risks related to the future environmental costs*
25 *associated with CO₂ emissions, were key concerns. Fossil fuel*
26 *prices and environmental costs associated with emissions*
27 *from these plants are among the most serious risks SCE&G*
28 *and its electric customers face. Adding more gas or coal*
29 *capacity to meet base-load needs in the 2016-2019 period*
30 *would increase SCE&G's exposure to those risks.*

31 TR. at 190. Our decision to construct the Units and our justification of
32 them before this Commission was not based on a simplistic analysis of

1 future costs based on one set of assumptions as to future natural gas prices
2 or carbon emission costs.

3 **Q. PLEASE EXPLAIN.**

4 **A.** As I indicated in my testimony in 2008, I have been involved in base
5 load planning decisions since the early 1990s when I led the team that made
6 the decision to build the Cope Generating Station. During this time, I
7 learned that the key to making prudent base load planning decisions is to
8 understand that fossil fuel markets, and now environmental policies as to
9 fossil fuel, are inherently volatile and cannot be predicted with certainty.
10 Market conditions and regulatory requirements will change in ways that
11 cannot be predicted over the 40-year plus period that fossil plants will be in
12 service. It is a fundamental mistake to believe that sound base load
13 planning decisions can be made simply by modeling outcomes based upon
14 current projections of future fossil fuel costs or regulatory conditions. Such
15 one-dimensional analysis does not take into consideration the dynamic
16 energy markets in which we operate or our inability to know with certainty
17 what market, regulatory and operating conditions will be decades in the
18 future. In this context, one-dimensional analyses are dangerous and expose
19 our customers to risk.

20 For SCE&G, this exercise is not theoretical. More than 660,000
21 customers depend on SCE&G for reliable, efficient electric service. To
22 meet their needs, SCE&G must build a generation portfolio that can

1 provide reliable, efficient service under varying future conditions which are
2 difficult to predict. Making base load selection decisions on one-
3 dimensional analyses like Dr. Cooper's is not how SCE&G can best fulfill
4 its future service obligations to its customers.

5 **Q. HOW DOES NUCLEAR GENERATION COMPARE TO**
6 **COMBINED CYCLE GENERATION WITH REGARD TO FUEL**
7 **PRICE VOLATILITY?**

8 A. Fuel costs represent only about 13% of the busbar cost of nuclear
9 generation, compared to new combined cycle gas plants, where fuel costs is
10 still 41% of the cost of the busbar cost even at today's low gas prices.
11 From a fuel cost perspective, the busbar cost of nuclear power is inherently
12 less volatile than fossil fuel generation.

13 **Q. WHY IS ACCOUNTING FOR VOLATILITY AND THE LACK OF**
14 **KNOWLEDGE AS TO FUTURE CONDITIONS SO IMPORTANT**
15 **IN GENERATION PLANNING?**

16 A. Generation assets are designed and built to last for decades. Five of
17 SCE&G's base load facilities are 40-years old or older. Under its existing
18 license, V.C. Summer Nuclear Station ("VCSNS") Unit 1 will provide
19 service for 60 years. Three of our hydro facilities predate World War I.
20 One of our most fuel-efficient coal plants—in fact the eighth most fuel-
21 efficient coal plant in the nation—is McMeekin Station which is 54 years
22 old.

1 In this case, the scenario planning horizon is 40 years. When
2 dealing with planning horizons of this length, one thing is certain:
3 Whatever accepted wisdom and expert predictions say at any one point in
4 time about future fuel prices, environmental restrictions or operating
5 conditions, the actual conditions over the life of the asset will be different.

6 **Q. HOW DO EXPERIENCED PLANNERS RESPOND TO THIS**
7 **UNCERTAINTY?**

8 A. Experienced planners formulate generation plans by evaluating
9 multiple sets of price and regulatory assumptions that encompass a broad
10 range of possible conditions that the system may encounter over the 40-
11 year planning horizon. No one scenario dictates the selection decision, as
12 Dr. Cooper's testimony would suggest. Instead, the modeling results for
13 many different scenarios inform the evaluation. The goal is to determine
14 what generation choices lead to the most flexible, resilient and robust mix
15 of generation resources. The mix we seek is the one that can perform best
16 under the widest range of possible market, operating and regulatory
17 conditions, and that preserves for SCE&G and its customers the best
18 options for dealing with future uncertainty.

19 **Q. WHAT ROLE DOES THE IDEA OF A GENERATION PORTFOLIO**
20 **PLAY IN THE DECISION TO BUILD THE UNITS?**

21 A. Experienced planners also recognize that customers are not served
22 by individual plants, but by generation systems with multiple generation

1 resources. Robust generation systems contain a diverse mix of plants, each
2 with their own advantages and disadvantages regarding operating
3 restrictions, fuel costs, fuel supply and transportation issues, and
4 environmental regulations. A diverse portfolio of plants enables a
5 generating system to perform well in multiple contexts and to respond to
6 the inherent volatility in fuel prices, fuel supply and transportation issues,
7 operating conditions and environmental regulations. Generating systems
8 that are too highly concentrated on any single fuel type or generating
9 technology cannot do so.

10 **Q. HOW DID SCE&G EVALUATE FUEL COSTS AND PORTFOLIO**
11 **RISK IN ITS ANALYSIS?**

12 A. As our manager of generation planning, Dr. Lynch, testified in the
13 2008 proceedings, SCE&G evaluated its generation options based on plans
14 that added either natural gas-fired generation, coal-fired generation or
15 nuclear generation to the system. As to natural gas-fired generation, several
16 different plans were considered. Each involved different mixes of
17 combined cycle units, peaking units and purchased power contracts. All of
18 the plans, including the nuclear generation plan, involved additional gas-
19 fired generation being added at points along the way during the 40-year
20 planning horizon to supplement other base load and intermediate load units.
21 As Dr. Lynch testified, additional gas-fired generation could be replaced as

1 future conditions warranted with solar, wind, bio-mass, or demand side
2 management/energy efficiency ("DSM") resources.

3 Dr. Lynch and his team analyzed these alternative generation plans
4 over a 40-year planning horizon and across multiple scenarios. Each
5 scenario contained different assumptions about coal prices, natural gas
6 prices, nuclear fuel prices and carbon emissions prices as well as multiple
7 assumptions as to the rates of escalation for each relevant item. Each plan
8 and each set of assumptions was run through the Company's generation
9 dispatch models to determine how the generation system would respond to
10 the different conditions they contained. That dispatch modeling computed
11 indicative fuel costs for each plan and the multiple scenarios under it.
12 Similar computations were made for capital and other costs. Analyses were
13 also run to see how each of the different plans would respond to conditions
14 such as increased forced outage rates in our aging coal units or the early
15 retirement of smaller coal units.

16 **Q. WAS THIS ANALYTICAL MODELING THE END OF THE**
17 **EVALUATION AND SELECTION PROCESS?**

18 A. Not at all. This analytical modeling was not the end of the resource
19 selection process, but the beginning. SCE&G's management team
20 reviewed, digested and evaluated the data Dr. Lynch's team created to
21 answer one question: Which type of generation would contribute to a
22 generation portfolio that could best respond to the widest range of potential

1 conditions in fuel markets, operating conditions and environmental costs
2 over the coming decades and give SCE&G the most options to respond to
3 unanticipated conditions in the future? No single analysis or set of
4 assumptions as to future natural gas costs, operating conditions or
5 environmental costs determined our decision. That decision was informed
6 by information about how the different configurations of the system would
7 perform across multiple sets of assumptions, combined with the business
8 judgment and the collective wisdom of an experienced team of planners,
9 engineers and executives.

10 **Q. WHAT WAS THE RESULT?**

11 A. We concluded then, and still believe today, that adding nuclear
12 generation creates a system that can perform best in the widest range of
13 conditions over the coming decades. As I mentioned in my direct
14 testimony in this docket, by adding nuclear generation, our generation mix
15 in 2019 will be 27% coal, 28% natural gas, 31% nuclear and 14%
16 hydro/biomass. This will give us the flexibility to switch between coal and
17 gas generation as conditions warrant. It will mean that in 2019, we will
18 have reduced our carbon emissions by 54% compared to their levels in
19 2005, giving us a secure position if carbon taxes, cap and trade systems, or
20 other regulatory mechanisms impose costs on carbon emissions. Our
21 balanced generation portfolio will also mean that as we go forward from
22 2019, we would have the option to add additional natural gas-fired

1 generation to our system without fear of becoming overly reliant on natural
2 gas as a fuel. We can also add resources like solar, wind or DSM where
3 feasible knowing that standing behind them is a secure foundation of
4 reliable generation.

5 As I testified in 2008:

6 *[N]uclear generation proved to be the most beneficial option*
7 *in precisely those scenarios where the costs of operating*
8 *SCE&G's other generating units would be highest and the*
9 *availability of lower cost nuclear power would be of most*
10 *benefit to customers. Conversely, in those analyses where*
11 *nuclear generation was a higher cost alternative, the costs of*
12 *operating existing coal and gas plants would be lower than*
13 *anticipated and these lower costs would serve to hold overall*
14 *generation costs down.*

15 Weighing the range of possible outcomes, the better choice from a long-
16 term perspective was a generation plan that included new nuclear
17 generation. SCE&G did not base its choice on any single cost analysis or
18 any single forecast of fuel costs or environmental conditions.

19 **Q. ARE CURRENT GAS FORECASTS SUBJECT TO CHANGE?**

20 **A.** Yes, if there is anything that I have learned in my more than 30 years
21 of experience in this industry, it is that current gas price forecasts—
22 whatever they are—will change. The projections on which Dr. Cooper
23 relies were different four years ago, and in all likelihood will be different
24 four years from now. The prudent approach is to do as SCE&G has done
25 here, which is to make its generation selection decision based on operating
26 experience, knowledge of our system and markets, and the careful review

1 of robust, multi-scenario analyses of the generation alternatives under
2 different assumptions as to fuel prices, operating assumptions and
3 environmental regulations.

4 **Q. DOES THE PROGRESS OR COST OF THE CONSTRUCTION OF**
5 **THE UNITS IN ANY WAY SUPPORT THE NEED TO**
6 **REEVALUATE THEIR PRUDENCE?**

7 A. Quite the contrary. As my direct testimony, and that of Mr. Byrne
8 show, the construction program for the Units is going well. As to the Units,
9 uncertainties regarding permitting and design, NRC licensing, initial site
10 work, transmission siting, environmental review, and equipment
11 procurement have been reduced. The schedule for the project as a whole
12 has been accelerated. More than two-thirds of the cost of the Units under
13 the Engineer, Procure and Construct Agreement ("EPC Contract") is now
14 either fixed or firm with fixed escalation rates. The all-in cost for the Units,
15 including escalation and transmission, is now approximately \$551 million
16 less than the figure we relied on in making the decision to build the Units.
17 Based on current escalation rates, the Units themselves have gone down in
18 total cost by approximately 8.7%.

19 **Q. HOW DO THE ENVIRONMENTAL COSTS OF CO₂ EMISSIONS**
20 **FACTOR INTO DR. COOPER'S ANALYSIS?**

21 A. Dr. Cooper's analysis does not calculate the effect of the costs that
22 might be imposed on CO₂ emissions from natural gas plants that SCE&G

1 might build to replace the nuclear Units he asks the Commission to order us
2 to abandon. This position also contradicts the position taken by the Sierra
3 Club which is to support the imposition of such costs.⁴ As mentioned
4 above, Dr. Lynch ran multiple scenarios in his analysis based on multiple
5 assumptions as to future CO₂ costs and the decision SCE&G made to select
6 nuclear was based on a review of that range of analyses. If we were to
7 replace the nuclear Units with natural gas fired generation or estimate based
8 on 2020 values that the result would be a 300 million ton increase in
9 SCE&G's CO₂ output over 60 years.

10 We do not know what future limitations or costs may be imposed on
11 CO₂ emissions from natural gas plants. We are not in a position to
12 conclude that there will be none and to make the decision to abandon
13 billions of dollars of investment on that basis.

14 **Q. WHAT ARE YOU ASKING THE COMMISSION TO DO?**

15 A. SCE&G is asking the Commission to approve the updated cost
16 forecasts and construction schedules for the Units as presented in the
17 petition in this matter and in the direct testimony of Mr. Byrne, Ms. Walker
18 and other witnesses. SCE&G requests that the Commission find that the
19 changes in cost and construction schedules are the result of normal and

⁴ *Policy on Carbon Market Programs*, SIERRA CLUB, 1-2,
<http://www.sierraclub.org/policy/conservation/carbonmarkets.pdf> (last visited August 23, 2012).

1 expected changes in a project of this size and complexity, and have not
2 been shown by any party to be the result of imprudence by the Company.

3 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

4 **A. Yes. It does.**

1 **MR. BURGESS:** Mr. Chairman, Mr. Marsh is
2 available for cross-examination by the parties of
3 record, as well as any questions by the Commission.

4 **CHAIRMAN WRIGHT:** Thank you, very much. Mr.
5 Guild.

6 **MR. GUILD:** Thank you, Mr. Chairman.

7 **CROSS EXAMINATION**

8 **BY MR. GUILD:**

9 **Q** Good morning, Mr. Marsh.

10 **A** Good morning.

11 **Q** So, first, let's try to see if we can't understand what
12 the issues are that you've -- that the company has
13 presented to the Commission today. Now, you have a \$283
14 million cost overrun that you seek approval for,
15 specifically, from the Commission, today, correct?

16 **A** That's not correct. We have asked for updates in
17 capital cost schedules. I would not characterize those
18 as cost overruns. In the initial filing the company
19 made with the Commission is included about a \$438-\$439
20 million contingency line item, which was subsequently
21 disallowed by the Supreme Court until, they said, we
22 could itemize and identify and associate those charges
23 with specific cost categories. When that could be done,
24 we could come back to the Commission and have those
25 approved, which we've done one time for \$174 million in

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1 2010, and these additional costs of 283 would also be
2 taken out of that contingency fund.

3 Now, if you add the 174 and the 283, that would put
4 us slightly over the balance that was in that
5 contingency fund, by about \$18 million, which is less
6 than ½ percent of the total cost of the project. So I
7 would not characterize it that 283 is cost overruns.

8 Q All right. The total of the 174 and 283 is \$457
9 million?

10 A That's correct.

11 Q And that's \$457 million, Mr. Marsh, that's over and
12 above the amount that you could prove to the Commission
13 was prudent and reasonable at the time of your original
14 Base Load application, correct?

15 A I don't agree with that, because the petition we put
16 before the Commission included a line item for
17 contingencies, which we anticipated we would use those
18 funds for items such as the ones that make up the 174
19 and the 283 that we're talking about here today. So to
20 call those cost overruns -- all I would concede would be
21 cost overruns would be the additional \$18 million, which
22 we believe is prudent, which we've got testimony to
23 support here today, and not the whole amount.

24 Q All right. I don't mean to quibble, but the Supreme
25 Court disagreed with your contention and said that you

1 hadn't proved those contingencies were prudent and
2 reasonable, and therefore, you would have to come back
3 to the Commission and establish an evidentiary basis --
4 you'd have to prove -- that you were entitled to those,
5 and that's what you've done in the 174 and then today
6 the 283, correct?

7 A The Commission -- I mean, the Supreme Court said we
8 needed to identify and assign those to specific cost
9 categories, which we had done, which I believe was
10 anticipated in the initial filing of 2008 that was
11 approved by the Commission. So I don't -- from my
12 perspective, I don't believe that the costs were
13 disallowed; they were just -- had to be identified
14 before the Commission would agree to include those in
15 the updated cost schedules.

16 Q All right. So, I'm just trying to think conceptually
17 how we disagree about this. It's your position that
18 virtually all of the total of \$457 million -- the 174
19 and 283 -- were costs that you anticipated at the time
20 you came to the Commission in 2008.

21 A They were costs that would have been in cost categories
22 that were included in the presentation to the
23 Commission, which included a contingency of \$438-\$439
24 million.

25 Q Right. So, all of the things that your Witness Byrne

1 describes and your Witness Lavigne describes were things
2 that you expected to have to incur, costs you expected
3 to incur, in 2008 when you first came to this
4 Commission. You just didn't prove that you were
5 entitled to those costs at the time of your initial
6 application.

7 A I think it's a little bit broader than that. When
8 you're talking about a \$5.8 billion project, there will
9 be changes along the way that require updates of costs
10 or changes in the scheduling, for the benefit of the
11 project. In this case, the costs we're talking about
12 were costs that our team went back and, based on their
13 knowledge and experience of building plants and the
14 available information in the industry and what they knew
15 about the construction schedule at the time, they
16 brought these costs back to the Commission and felt like
17 they were necessary adjustments to the cost schedule to
18 improve our likelihood of success on the project.

19 To say that we, you know, didn't know anything
20 about them I don't think would be accurate, because we
21 talked about these types of costs in 2008. And while we
22 have raised the amount, that's based on our additional
23 knowledge of the project as we've gone along in the day-
24 to-day management of the day-to-day activities on-site.

25 Q Well, I guess what I'm having conceptual trouble with --

1 and I won't belabor the point -- is, it seems to me you
2 can't have it both ways, Mr. Marsh. Either, at the
3 time, you anticipated these costs and should have
4 demonstrated that they were prudent and reasonable
5 initially, or you didn't. And I think you're telling me
6 both things. Now, if you did anticipate these costs but
7 you didn't bother to tell the Commission about them at
8 the time, is it prudent for the Commission to approve
9 them today?

10 A Well, let me see if I can give you an example to clarify
11 my position. We had in the project when we started a
12 cost identification line for excavation at the plant
13 site. We did a lot of boring and samples to make sure
14 we understood what we thought the ground would look like
15 when we dug down 45 feet, but we didn't dig that 45 feet
16 before we started the project. Now, we did samples and
17 test samples to make sure we could understand what we
18 believed would be down there in terms of the rock
19 formation of the foundation. After we excavated to 45
20 feet, we found some variation in the rock that, you
21 know, we didn't anticipate, but could be there. And as
22 a result, we're having to spend additional dollars to
23 fix that, and that's some of the dollars that are
24 included in the costs we've included here today.

25 So, yes, we anticipated we would have to excavate

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1 the land to do the work on the plants. We did test
2 borings, we did analysis to give us the most reasonable
3 expectation of what that would cost. When all the dirt
4 was removed, there were some cracks in the rock that had
5 to be filled before we could start the basemat
6 preparations to pour the initial concrete. So that, to
7 me, is not imprudent. I mean, to be imprudent would be
8 to get down that far and not fill the cracks and not do
9 the work and try to build a nuclear plant on top of it.
10 I think we're doing the right things to demonstrate, you
11 know, prudence in construction, and sound practices.

12 Q So either you did or didn't anticipate that you were
13 going to have to dig out more rock than you actually
14 encountered. And I think your witnesses' prefiled
15 testimony made clear that you were surprised by how much
16 more rock you had to get to. Isn't that right?

17 A Well, we don't have the ability to see through 45 feet
18 of dirt until you remove it.

19 Q So that's a category of cost that's in addition to the
20 costs that you anticipated and told this Commission
21 about. It either falls into one category or the other,
22 Mr. Marsh.

23 A No, I think we see it differently. I don't see it as an
24 additional cost. It's more money that we'll spend on
25 that line item, but it's not a new cost. We identified

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1 that cost in the filing as something we would have to --

2 Q Well, sure.

3 A -- do.

4 Q I mean, you're going to have to put steel out there, but
5 the question of how much steel is an open issue until
6 you finish the design and perhaps actually put the steel
7 up. But the fact of that matter is, digging a hole
8 being a category of costs doesn't answer the question of
9 whether the dollar amount that you told us and told the
10 Commission it would cost you to dig a hole and fill it
11 with concrete was reasonable and prudent at the time, or
12 whether or not you now find that you have imprudently
13 estimated the cost it would take to do that. It's one
14 way or the other, isn't it, Mr. Marsh?

15 A I don't think so, based on the way you characterized it.
16 I mean, it's not reasonable to assume that you're going
17 to build a project that's going to cost \$5.8 billion and
18 there won't be some changes in costs along the way.
19 Some of those costs would go up, some of those costs
20 would go down. I mean, we estimated the cost of
21 financing this project, I think, somewhere around 6.2
22 percent on our first mortgage bonds. We've issued bonds
23 today that are significantly lower than that, and it's
24 going to save our customers \$360 million. Based on your
25 scenario, we would expect to keep the \$360 million if we

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1 told the Commission that's what it was going to cost and
2 it cost less. But we didn't. We're not going to do
3 that. So the costs go up and costs go down, which is
4 why we look at the totality of the project, which is
5 what I look at. We're on schedule, on budget. The cost
6 is some \$550 million less than what we anticipated, and
7 yes, there have been schedule changes. There have been
8 some costs that have gone up; there have been costs that
9 have gone down.

10 Our commitment to the Commission was we would give
11 you, in the 2008 filing, or the BLRA, our estimate of
12 costs. Our commitment was if that changed we would come
13 back to the Commission and let them know what those
14 changes were and seek to have adjustments made in the
15 cost schedules because we thought those were prudent,
16 and that's what we're here doing today.

17 So from the standpoint of, you know, do these \$283
18 million add to the cost of the project? I don't think
19 so, other than the 18 that's over and above what was
20 initially approved by the Commission. We just have to
21 go through a different process of having those approved.
22 But even with the \$18 million over the contingency fund
23 at this point, we are well below what we said we were
24 going to spend, so from that perspective, I don't think
25 we're over-budget.

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1 Q All right. So the \$550 million that you want to take
2 credit for, that's not in 2007 construction dollars;
3 that's taking advantage of what the economy generally
4 has enjoyed, and that is, lowest all-time interest
5 rates.

6 A Those are real costs. Those impact the cost --

7 Q Yes, but --

8 A -- of the project.

9 Q Yes, but you've been telling the Commission that we
10 should analyze this project based on fixed 2007 dollars,
11 and on that basis you're asking for another \$283 million
12 to be approved to that project budget, aren't you?

13 A I don't think that's correct. I believe, in the Base
14 Load Review filing, that the cost approved is the
15 escalated cost of the project at the date it'll go in
16 service; it's not the 2007 dollars. The 2007-dollar
17 number is just to give us a reference point by which we
18 can measure if there were changes in the original costs
19 as they were put forward.

20 Q All right. In those terms, you're here today asking for
21 \$283 million over and above what the Commission and the
22 Supreme Court approved in the 2007 budget for this
23 project, correct?

24 A No. The approved budget for the project originally by
25 the Commission was \$6.3 billion. There were adjustments

1 to that from the Supreme Court because they said you
2 cannot include the 400 in the cost schedules until --
3 for the escalation -- until you specifically identify
4 and assign those to cost categories, which we have done
5 in 2010 and we are doing here today. I don't believe it
6 was the Supreme Court's decision to -- intention to
7 allow us not to recover those costs, once they were
8 identified. So I don't believe the 283, from my
9 perspective, is all new costs. The majority of that was
10 anticipated. It would have been taken out of the
11 contingency, for a project of this size for which a
12 contingency is not unreasonable.

13 Q All right, sir. Let's change the subject. You used the
14 term "prudent and necessary" in your summary, and I
15 believe you would concede that prudence is the standard
16 that's appropriate for this Commission to consider in
17 reviewing your proposed approval for the \$283 million in
18 adjustments to the construction budget, correct?

19 A I think that's the purpose of the process that was laid
20 out in the Base Load Review Act, to bring those costs
21 before the Commission when there were changes and let
22 them determine whether or not they were prudent.

23 Q All right, sir. And prudence was the standard that this
24 Commission used in their initial Base Load Review Act
25 approval to initiate construction of Units 2 and 3 at

1 the Summer Station, correct?

2 A That's correct.

3 Q Okay. And, in addition, the Base Load Review Act
4 contemplates that, at some point in time, if the project
5 -- that is, the construction of Units 2 and 3 at Summer
6 -- were abandoned, that at that point the Commission
7 would likewise use a standard of prudence to determine
8 whether or not the decision to abandon was prudent and,
9 therefore, the sunk costs to date for the project should
10 be recoverable from rates; isn't that correct?

11 A I believe that's my understanding, subject to review by
12 my attorneys. But my understanding is, it's the prudent
13 costs that were spent to date on the project. If the
14 Commission determines that those costs were prudent and
15 it was prudent to stop construction of the plant, those
16 costs would be passed through to customers under the
17 Base Load Review Act.

18 Q All right, sir. Now, you characterized what Dr. Lynch
19 has done for your company in his presentation here, and
20 in his duties generally, is the undertaking of -- I
21 think I wrote it down correctly -- a complex, multi-
22 scenario analysis of generation options for the company.
23 Is that what you understand is Dr. Lynch's role?

24 A Yes.

25 Q All right. And you fault Dr. Cooper, in your rebuttal

1 to his initial testimony, with not having done such a
2 multi-scenario, complex analysis, correct?

3 A My evaluation of his testimony was to measure the impact
4 of the change in natural-gas prices.

5 Q Without considering other alternatives or variables,
6 correct?

7 A Yes.

8 Q Now, my question for you is, does the company routinely
9 perform such complex, multi-scenario analyses of the
10 going-forward decision with respect to the Summer Units
11 2 and 3 project?

12 A I can tell the Commission with assurance there's
13 probably not a day that's gone by since we started
14 construction on these new plants that I'm not thinking
15 about these plants and how well the construction process
16 is going, or do we have challenges, do we have issues we
17 need to deal with. It's an ongoing monitoring process.

18 If issues came to our attention that we believed
19 would determine that this project would no longer be
20 prudent to move forward, I believe it would be my
21 obligation to bring that information to the Commission.
22 We just haven't seen that to date. The project is going
23 as planned. The construction is going well. We're \$550
24 million under-budget. We fixed an additional, you know,
25 percentage of the costs of the plants so we have almost

1 two-thirds of the costs that are fixed. We've only got
2 now a fourth of the project left to spend in those
3 categories that are subject to escalation. I mean,
4 we've had a lot of success on this project, and --

5 Q Yes, sir, but that's not my question. I hate to
6 interrupt, but I really would like you to focus on my
7 question, if you will. The specific question I asked
8 you is, has your company routinely performed a complex,
9 multi-scenario analysis of the decision to go forward
10 with construction of this plant. Not whether you've
11 monitored construction or care about it, but have you
12 routinely performed just that multi-scenario, complex
13 analysis of the decision to go forward?

14 A Well, what I was trying to say was, before I would
15 instruct someone to go do an analysis just on a monthly,
16 weekly, or an annual basis, I would have to have some
17 basis for believing something had changed. I mean, if
18 nothing has changed in the circumstances based on which
19 we made the decision, I don't think it's necessary to go
20 back and rerun an analysis.

21 Q So do I take it from that answer that the answer is, no,
22 you have not routinely done such a multi-variable --
23 multi-scenario, complex analysis of the decision to go
24 forward.

25 A We do -- we would update the evaluation if we considered

1 it to be necessary to evaluate the status of the
2 project.

3 Q All right.

4 A What I was trying to say earlier was, we don't know of
5 anything that has risen to that level that would give me
6 a concern, based on my years of experience in the energy
7 industry, that would have changed the conclusion that we
8 would have drawn in 2008, that would have required me to
9 instruct Joe, Dr. Lynch, to go back and perform an
10 analysis. I certainly wouldn't have him do that on a
11 weekly or monthly basis just so he could keep his skills
12 intact at doing that. He knows how to do that.

13 Q Have you done it at all? Have you done it even once,
14 had Dr. Lynch or others in your staff conduct what you
15 characterize as a complex, multi-scenario analysis of
16 the decision to continue construction of Units 2 and 3?

17 A We have done that. It was clear, after we got the
18 surrebuttal from Dr. Cooper, that he was not satisfied
19 with the responses we had in our testimony and our
20 rebuttal testimony, so I did instruct Dr. Lynch to go
21 back and update the study that was done in 2008 that had
22 served as the basis for making the decision to move
23 forward with nuclear as the best alternative for our
24 customers. He did the study. It concluded, by a wide
25 margin, that new nuclear was --

1 Q Well, let's --

2 A -- the best option to --

3 Q -- let him talk about what it says, okay? I mean, we'll
4 get to that, Mr. Marsh. That's really hearsay. But you
5 say you, as a result of Dr. Cooper's analysis in this
6 case, instructed Dr. Lynch to conduct an analysis -- and
7 that was the analysis that got sent to me last Thursday;
8 is that right? 27th of September, filed with the
9 Commission?

10 A You know, first of all, I don't believe Dr. Cooper did a
11 comprehensive analysis. He made some calculations based
12 on changes in gas prices. I don't consider that to be a
13 multifaceted analysis like Dr. Lynch did after I
14 instructed him to go back and update the complete
15 analysis we did in 2008, which was the basis for the
16 decision to --

17 Q Help me, now. I don't mean to cut you off, but --

18 A All right.

19 Q -- real simple question, as a matter of fact. The
20 analysis you were just referring to is the one that was
21 filed with the Commission and served on me last
22 Thursday, and that's the one you asked Dr. Lynch to do
23 as a result of reviewing Dr. Cooper's analysis, correct?

24 A That's correct.

25 Q Okay. Now, aside from that submission, that update,

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1 that review of the decision to go forward with the
2 plant, have you communicated -- have you submitted any
3 other such complex, multi-scenario analysis of the
4 decision to go forward, to the Public Service
5 Commission?

6 A To my knowledge, there's not a requirement under the
7 Base Load Review Act for us to do that on a regular,
8 consistent basis. Our commitment under the BLRA is to
9 provide you with monthly -- I mean, quarterly reports to
10 give you status updates on where the project is, on the
11 issues we've got, how things are going. We are required
12 to give the Commission an annual update, which we've
13 done every year since the project was started. Mr.
14 Byrne's testimony will satisfy that requirement with the
15 Commission today. ORS is on-site on a regular basis;
16 they look at the information and they monitor the
17 project. So there is ongoing oversight of this project.
18 And as I said earlier, it's not a requirement that we do
19 that, but I feel it's my obligation, as CEO of the
20 company, that if something rose to the level that would
21 convince me that the project, you know, may not be
22 prudent, then I feel like I would have an obligation to
23 revise the evaluation, bring that to the Commission, and
24 make the decision in conjunction with the testimony we
25 presented before them. You know, we did that. While I

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1 don't think we were required to do that, we did that, in
2 response to the surrebuttal from Dr. Cooper. And lo and
3 behold, it confirmed exactly what we thought, based on
4 our experience and evaluation of the project today.

5 Q Okay. The question for you is simple. Prior to that
6 which you sent on Thursday, filed with the Commission --
7 and Dr. Lynch will address in his testimony -- have you
8 ever submitted such a revised analysis of the decision
9 to go forward with the project to this Commission or to
10 ORS before last Thursday, ever?

11 A We have not, because we didn't believe it was required,
12 and based on our experience in the industry we didn't
13 think anything had changed to the point or would rise to
14 the level of significance that would require us to do
15 so.

16 Q All right, sir.

17 A The study we completed, based on Dr. Cooper's -- after
18 reading his testimony, confirmed that.

19 Q Well, let's test that last assertion. So you don't
20 think enough has changed or anything material has
21 changed since 2008 to cause you to reconsider or even
22 reanalyze, until last Thursday, the decision to go
23 forward.

24 A I do not.

25 Q Well, are you surprised, Mr. Cooper_[sic], that the nuclear

1 had a certified design. And I believe 19 was the last
2 design that was incorporated into that final approval
3 for the reference plant. It may have been 20, but I
4 believe it was 19.

5 Q Because they're on 20 right now, correct? They're
6 working on 20?

7 A I'll let Mr. Byrne address the details of that.

8 Q Okay. Well, when you came to this Commission, it was
9 Revision -- was it Revision 16 or 17 that you had come
10 to this Commission for approval on?

11 A I'll again defer that to Mr. Byrne, but my memory is,
12 when the design was originally certified, the
13 preliminary design for Westinghouse, I believe that was
14 through DCD 15. There were a number of revisions that
15 came after that, and we probably were at 16 or 17
16 revisions at the time we came, but Mr. Byrne can confirm
17 that.

18 Q So the reference plant wasn't finished through Revision
19 19 before you even came to this Commission for their COL
20 approval?

21 A My understanding is there was a preliminary approval of
22 the AP1000 design. The final approval would be given
23 for the reference plant, which originally was the
24 Bellefonte plant you alluded to in your opening
25 statement, and that had shifted to Southern plant as the

1 reference plant -- Southern Company plants.

2 **Q** What happened at Bellefonte that caused them to shift it
3 from Bellefonte?

4 **A** I think -- I believe they canceled their project. Mr.
5 Byrne can confirm the circumstances.

6 **Q** Okay. I think I might need to save most of my questions
7 for Mr. Byrne. Let me go to something else here, then,
8 for you, if you don't mind. This idea of delay assumes
9 that -- okay, let me just kind of backtrack on this
10 timeline that I have here. The NRC issued your COL in
11 March 2012. And when you submitted your design to them,
12 it was -- you actually submitted your COL to the NRC
13 before you submitted your design -- your COL before the
14 Public Service Commission. And then at a later date,
15 they docketed it later. But we're back, again, on
16 Revision 16 or 17. So, even going to the NRC, you
17 didn't have Revision 19 to work with.

18 **A** Well, the application for --

19 **CHAIRMAN WRIGHT:** Mr. Marsh, would you get a
20 little closer to the mic?

21 **WITNESS:** I'm sorry [indicating].

22 **CHAIRMAN WRIGHT:** Thank you.

23 **WITNESS:** The application that the company
24 filed with the NRC runs on a parallel path with the
25 approval of the reference plant. We had applied

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1 for the Combined Operating License with the NRC,
2 which by definition could not be approved until the
3 final reference plant documents were approved. So
4 they run on parallel paths. And I believe that
5 information was presented to the Commission at the
6 time.

7 And in the timeline, that's what led us to
8 believe we could have received the COL by July of
9 2011. It's not a process where you wait until you
10 receive the final design. I don't know that you
11 couldn't have done that, but the companies that
12 were applying were going on parallel paths.

13 BY MS. GREENLAW

14 Q Uh-huh. So the final reference plant approval still was
15 supposed to occur before you could get your COL?

16 A Yes, under the original plan, you would have had the
17 final reference plant approval prior to July of 2011.
18 So, by definition, we couldn't have been issued our COL
19 by the NRC until the reference plant had been approved.

20 Q So why did SCE&G believe that you were going to get your
21 approval in the middle of 2011, when the reference plant
22 was up in the air?

23 A Well, I don't think it was up in the air. There was
24 still final design work that was being done through the
25 DCD process. Our belief, working with Westinghouse and

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1 require us to notify the Commission.

2 **VICE CHAIRMAN MITCHELL:** Okay. Well, I'll
3 just save that for Mr. Byrne, then. Thank you,
4 sir. That's all I have.

5 **CHAIRMAN WRIGHT:** Commissioner Whitfield.

6 **COMMISSIONER WHITFIELD:** Thank you, Mr.
7 Chairman.

8 **EXAMINATION**

9 **BY COMMISSIONER WHITFIELD:**

10 **Q** Mr. Marsh, I've got a couple of questions. One may be
11 for Mr. Byrne, but it is in your direct testimony on
12 page 11, I believe. You discuss generation mix and you
13 talk about, on a capacity basis, your generation mix by
14 2019 would be 27 percent coal, 28 percent natural gas,
15 31 nuclear, 14 hydro and biomass. You also say, "By
16 2019, based on how we dispatch our plants, we project
17 that 60 percent of our energy will come from nuclear,"
18 hydro, and biomass, and only 24 percent would come from
19 coal.

20 And of course, while you're, I guess, ramping up a
21 little bit with the gas now, what I guess you're saying
22 in that scenario is that, by 2019, your gas would have
23 decreased pretty significantly also; is that correct?

24 **A** Well, if you're looking at it from a capacity basis, our
25 gas really won't change between now and 2019. But

1 unlike many utilities, we've already made a significant
2 commitment to natural gas. A lot of the companies today
3 that are making commitments to natural gas have very
4 little gas in their portfolio, so they're --

5 Q But on the dis- --

6 A -- trying to boost it.

7 Q On a dispatch basis.

8 A Well, even on a capacity basis, people would be
9 dispatching more if they had it. I believe many
10 companies that are adding to their systems today don't
11 have a level that we might consider appropriate for a
12 good generation mix. We're not adding gas between now
13 and 2019, so our capacity basis would not change. But
14 based on the way that gas is dispatched, once the
15 nuclear comes on-line, we would look at the cost
16 advantage of whichever fuel was the lowest at that point
17 and dispatch based on that basis. Based on our
18 forecast, and as we see today, our nuclear plant runs
19 seven days a week, 24 hours a day, as long as the plant
20 is up and running, because it is the cheapest we have on
21 the system, even relative to natural gas. So it runs
22 all the time for base-load needs. So we would do the
23 same thing once the new nuclear came on-line, to take
24 advantage of the low cost of nuclear fuel.

25 Q Well, also along those lines, by 2019 -- and I don't

1 recall if it was Mr. Guild or Ms. Greenlaw, but one of
2 them said in the opening statement -- made a comment
3 about what the cost per kilowatt-hour might be to the
4 ratepayers in 2019 when both these units are on-line --
5 or 2018, excuse me. Do you care to comment on that? It
6 was a figure somewhere 20 or 25 cents. I didn't exactly
7 write that down, either.

8 A Ms. Walker can give you that exact number, but it will
9 be higher than what it is today, because under the Base
10 Load Review Act, we are asking customers to pay for the
11 financing costs of the plant as we complete the
12 construction. So in each year, I think on average we've
13 got about a 2 to 2½ percent rate increase during the
14 construction of the project that we're asking to pass on
15 to customers. The benefit of that -- and which this is
16 something we learned from the '70s and '80s, because in
17 the '70s and '80s you just compounded that interest all
18 during construction, and then you brought that all on-
19 line at one time, which resulted in significant
20 increases at the time those plants come on-line. By
21 passing the financing costs on as we go, we will save a
22 billion dollars in capitalized interest, based on our
23 forecast, and then compounding that out for the 60-year
24 period we expect to operate these plants, that would
25 save another \$4 billion. So we're going to save \$5

1 billion, which is almost equal to the cost of the plant,
2 under the methodology adopted by the Base Load Review
3 Act.

4 So I think we tried to learn from the past and
5 minimize the impact now, but by putting those rate
6 increases in in smaller amounts, that should avoid a
7 significant increase. And our goal would be, with the
8 benefit of the fuel savings and the other benefits of
9 operating the nuclear plant, the customers might see a
10 decrease when those come on-line.

11 **COMMISSIONER WHITFIELD:** Thank you, Mr. Marsh.
12 That's all I have, Mr. Chairman.

13 **CHAIRMAN WRIGHT:** Okay. Commissioners?
14 Commissioner Fleming.

15 **COMMISSIONER FLEMING:** [Indicating.] I always
16 have trouble with that -- getting that red light to
17 show up.

18 **EXAMINATION**

19 **BY COMMISSIONER FLEMING:**

20 **Q** Good morning, Mr. Marsh.

21 **A** Good morning.

22 **Q** I'm paraphrasing this, I guess, or probably. But Mr.
23 Guild, in his opening statement, said that one
24 definition was showing care for the future, as I
25 understood it. How would you explain the investment in

1 these two nuclear units -- how would you respond to him,
2 in answer to that?

3 A I feel like my responsibility, and that of the company,
4 is to make a decision based on the generation needs of
5 the company; and also that the customers that we will be
6 serving, to make the decision that would be the most
7 prudent over the long term. And by "prudent," I think
8 it's the decision that results in the least-cost
9 alternative, with the least amount of risk for changing
10 conditions in the marketplace, and trying to account for
11 all of those factors in coming up with the best solution
12 that best addresses all of those.

13 You know, if I knew natural-gas prices were going
14 to stay at \$2 and \$3 for the next 60 years, and that was
15 guaranteed, and there wouldn't be any more environmental
16 regulations that would be on top and impact carbon, you
17 know, we might have chosen or put more emphasis on the
18 natural-gas strategy. But in the marketplace we live in
19 today, knowing there continues to be concern over
20 carbon, and based on my 35 years of experience in the
21 gas industry and the electric industry, the volatility
22 in gas prices, it's very risky for the company to have
23 over 70 percent of its generation in fossil-fired
24 plants, a combination of the coal and natural gas.

25 And I think back over my history in the gas

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1 industry; when I started doing audits in the '70s of
2 companies that had gas plants, they were only
3 depreciating those plants over 20 years. When I asked
4 the question, "Well, why only 20 years?" they said,
5 "There won't be any gas after 1997." Well, that didn't
6 turn out to be true.

7 You know, we got into the natural-gas business from
8 an oil and drilling perspective in the mid-'90s through
9 one of our SCANA subsidiaries, and despite the
10 unsuccessful efforts we had in drilling wells based on
11 the latest and greatest 3-D technology, you know, gas
12 prices were less than a dollar a dekatherm -- lower than
13 they are today -- but that didn't last. We went through
14 the periods of the high gas prices when we were trying
15 to, you know, put futures into place and trying to
16 manage what the cost of gas would be, based on
17 fluctuating gas prices. If it turned out that we put
18 hedges in place and the price went down, people weren't
19 happy about that, because they had to pay the cost of
20 the hedges.

21 So to look at natural gas over the long term and
22 try to put a plan in place to arrest all of those risks
23 and hold them in check is not feasible to us at this
24 point, or to do so I think would be cost-prohibitive or
25 expose our customers to risk, which I don't think would

1 be prudent.

2 I mean, the prudent thing, I think, we can do is
3 have a generation system that is a portfolio of
4 generation options -- nuclear, coal, natural gas, and
5 we've got hydro when that's available, and renewables
6 where it makes sense -- and gives us the ability to
7 change that mix from a dispatch perspective to take
8 advantage of whatever the most beneficial fuel price is
9 at the time, over the 60-year period. To lock into one
10 source of fuel, especially fossil fuels now with the
11 continued concern over carbon -- and I don't believe
12 carbon legislation is going away; I think it's coming
13 back in the next 60 years -- I think that would be
14 imprudent to put our customers in that position. So
15 when we did our analysis, that's what we were looking
16 at.

17 Q And if you had gone with the natural-gas route, would
18 you be able to achieve the same carbon-emission
19 reduction that you will with the nuclear by 2020 -- I
20 believe was your --

21 A We would not. Because carbon_[sic] produces about 50
22 percent of the same level as coal when it's burned.
23 It's lower, but it still produces carbon. So if that's
24 addressed in the future -- if they, you know, put
25 limitations on carbon emissions, with the nuclear

1 strategy we've got in place, I don't know of any plan
2 that's been presented to Congress or any legislation
3 that's been offered up that South Carolina wouldn't meet
4 hands-down with the new nuclear strategy.

5 COMMISSIONER FLEMING: All right. Thank you.

6 CHAIRMAN WRIGHT: Commissioners, anyone else?

7 [No response]

8 Mr. Burgess.

9 MR. BURGESS: We have no redirect of Mr. Marsh
10 and would ask that he be excused from the stand.

11 CHAIRMAN WRIGHT: You may step down. Thank
12 you. And you can be excused, Mr. Marsh.

13 [WHEREUPON, the witness was excused.]

14 MR. ZEIGLER: Mr. Chairman, the company would
15 call Mr. Steve Byrne to the stand.

16 CHAIRMAN WRIGHT: Mr. Byrne, good morning.

17 MR. BYRNE: Good morning.

18 [Witness sworn]

19 THEREUPON came,

20 S T E P H E N A . B Y R N E ,

21 called as a witness on behalf of the Petitioner, South
22 Carolina Electric & Gas Company, who, having been first duly
23 sworn, was examined and testified as follows:

24 <

25 <

DIRECT EXAMINATION

BY MR. ZEIGLER:

Q Please state your name for the record.

A My name is Stephen Byrne.

Q By whom are you employed and in what capacity?

A I'm employed by South Carolina Electric & Gas Company.
I'm the president for Generation and Transmission, and
chief operating officer.

Q Mr. Byrne, have you prepared or caused to be prepared
under your supervision prefiled testimony of 48 pages,
direct testimony, in this docket?

A I have.

Q And if I were to ask you -- are there any corrections to
that testimony?

A I have one correction. Page five at line number nine,
the word "geotechnical" should be changed to
"waterproof."

Q Very good. And with that change, would your answers to
those questions be the same today if they were asked
orally?

A They would.

MR. ELLIOTT: I'm sorry, Mr. Chair, I -- what
was the change? To what?

COURT REPORTER: "Geotechnical" to
"waterproof."

1 MR. ELLIOTT: "Waterproof"? Thank you.

2 BY MR. ZEIGLER:

3 Q And are there three exhibits attached to your testimony?

4 A There are.

5 MR. ZEIGLER: Mr. Chairman, we would move the
6 prefiled direct testimony of Mr. Byrne and his
7 exhibits be entered into the record at this time.
8 I would note the confidential versions of the
9 testimony and the public versions, as well as
10 confidential versions of one of the exhibits, and
11 we would ask the court reporter to take that into
12 consideration as she prepares the record.

13 CHAIRMAN WRIGHT: Very good. We will -- Mr.
14 Byrne's direct testimony, as corrected, as well as
15 his three exhibits, both public and confidential,
16 will be entered into the record. I guess, first,
17 the testimony as if given orally from the stand, as
18 corrected.

19 [See pgs 170-214 - Public Version]

20 [See pgs 216-260 - Confidential Version]

21 And then the exhibits, you've got both public
22 -- and that will be Exhibit No. 1, as a composite
23 exhibit, both the public and the confidential
24 versions will be.

25 MR. ZEIGLER: Very good, Mr. Chairman.

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1 **CHAIRMAN WRIGHT:** And she'll take care of it.

2 **MR. ZEIGLER:** Thank you, Mr. Chairman.

3 [WHEREUPON, Hearing Exhibit No. 1,
4 including both Public and
5 Confidential/Sealed Versions of SAB-2,
6 was marked and received in evidence.]

7 **BY MR. ZEIGLER:**

8 **Q** Mr. Byrne, have you prepared rebuttal testimony in this
9 docket?

10 **A** I have.

11 **Q** And that's 15 pages in length?

12 **A** It is.

13 **Q** Are there any corrections or changes to that?

14 **A** There are none.

15 **MR. ZEIGLER:** I would move both --

16 **BY MR. ZEIGLER:**

17 **Q** If I asked you those same questions contained in your
18 rebuttal testimony, would your answers today from the
19 stand be the same?

20 **A** They would.

21 **MR. ZEIGLER:** Mr. Chairman, I would move the
22 rebuttal testimony of Mr. Byrne into the record.

23 **CHAIRMAN WRIGHT:** Mr. Byrne's rebuttal
24 testimony will be entered into the record as if
25 given orally from the stand.

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[See pgs 266-280]

BY MR. ZEIGLER:

Q And, Mr. Byrne, I believe there's one exhibit to your rebuttal testimony, is there not?

A There is.

MR. ZEIGLER: I would move that also be entered into the record.

CHAIRMAN WRIGHT: And his rebuttal exhibit, I guess No. -4, will be entered as Exhibit No. 2.

[WHEREUPON, Hearing Exhibit No. 2 was marked and received in evidence.]

MR. ZEIGLER: Very good. And there are no confidential materials in those documents, I don't believe.

BY MR. ZEIGLER:

Q Mr. Byrne, have you prepared a summary of your direct testimony?

A I have.

Q I'm going to take a second and get your slides ready to go, because I think they're a part of that.

[Indicating.]

Mr. Byrne, could you give your prepared summary to the Commission and the parties?

A Certainly. Good afternoon, Mr. Chairman and members of the Commission. My testimony discusses the current

1 status of the construction of the new nuclear units, the
2 agreement between SCE&G and Westinghouse/Shaw resolving
3 EPC contract claims outstanding in March 2012, the three
4 other EPC contract change orders at issue in this
5 proceeding, and the operational, contractual, and other
6 matters related to the updates to the cost schedules
7 proposed in this proceeding. I'm also providing the
8 Commission with the annual status report concerning
9 construction of the units, as required by the initial
10 Base Load Review Act -- or BLRA -- order.

11 I've categorized the current status of this project
12 by saying that most of the site discovery work is now
13 complete. By that, I mean that every construction site
14 has conditions that are not apparent until a substantial
15 amount of work has been completed. Because of the work
16 done to date, we now know a great deal about the site
17 and its conditions. Additionally, we know our
18 contractors, Westinghouse and Shaw, and how we must work
19 with them to be effective. We know the supply chain, as
20 the major procurement orders for the project have been
21 placed. Each of the nuclear steam supply system
22 components for the AP1000 units has been fabricated
23 successfully at least once, and for some components
24 several times over. Much of the major equipment for
25 Unit 2 is either in the final stages of manufacture or

1 is complete, and material procurement is largely
2 complete for the major equipment for Unit 3.

3 Relative to permitting, we received our Combined
4 Operating License, or COL, from the Nuclear Regulatory
5 Commission on March 30th, and our Clean Water Act
6 Section 404 wetlands permit on the same day. We're
7 awaiting final action on permitting for our wastewater
8 systems and discharge systems. We anticipate receiving
9 those soon. Otherwise, our major construction permits
10 are in hand. Additionally, construction permits will be
11 obtained -- sorry. Additional construction permits will
12 be obtained as required.

13 I would now like to present an overview of the
14 construction, using photographs from the project. And
15 if it's acceptable, I'm going to step over, and I'm
16 going to drive while we view from the screens
17 [indicating].

18 [Reference: Hearing Exhibit 1 / {Amended} SAB-
19 1, Pg 1-of-44]

20 The first slide you're looking at is our reactor
21 vessel. This is the reactor vessel for Unit No. 2. You
22 can see that it's turned on its side here, and this is
23 at the Doosan facility in South Korea.

24 [Reference: Hearing Exhibit 1 / {Amended} SAB-
25 1, Pg 2-of-44]

1 This next slide is the same reactor vessel after
2 having satisfactorily completed its hydrostatic test, so
3 this is now ready for shipment to the site.

4 [Reference: Hearing Exhibit 1 / {Amended} SAB-
5 1, Pg 3-of-44]

6 One of the large components of our reactor coolant
7 system is a large tank called a pressurizer, which
8 allows us to control pressure. This is that pressurizer
9 at the facility in Italy, undergoing heat treating.

10 [Reference: Hearing Exhibit 1 / {Amended} SAB-
11 1, Pg 4-of-44]

12 Steam generator. This is a schematic of the steam
13 generator. A steam generator is just a big heat
14 exchanger. It normally sits vertically. This is
15 horizontally because the next picture is going to be
16 horizontal. And I'm just circling the area here in blue
17 which is the top of the tubes. The tubes actually carry
18 the reactor coolant system water and allows the transfer
19 of the heat to the secondary system water, which is then
20 converted into steam. So that top tube section's going
21 to be on the next diagram.

22 [Reference: Hearing Exhibit 1 / {Amended} SAB-
23 1, Pg 5-of-44]

24 And this again is at the Doosan facility in South
25 Korea.

1 [Reference: Hearing Exhibit 1 / {Amended} SAB-
2 1, Pg 6-of-44]

3 Accumulator tanks: this is at the Mangiarotti
4 facility in Italy. Each of the AP1000s has a couple of
5 accumulator tanks. You can see that this is the
6 fabrication of those accumulators.

7 [Reference: Hearing Exhibit 1 / {Amended} SAB-
8 1, Pg 7-of-44]

9 Inside of our reactor vessel we have components
10 that actually hold the core, and those are called core
11 internals or reactor vessel internals. Part of that is
12 the upper core barrel, and this is an upper core barrel
13 undergoing fabrication at the facility in Japan.

14 [Reference: Hearing Exhibit 1 / {Amended} SAB-
15 1, Pg 8-of-44]

16 Toshiba, which is the parent company for
17 Westinghouse, is building our turbines for us, and this
18 is one of the low-pressure turbine rotors at the
19 facility in Japan.

20 [Reference: Hearing Exhibit 1 / {Amended} SAB-
21 1, Pg 9-of-44]

22 Switching now to the site, this is an aerial view
23 of the site from March of 2012, so this is about the
24 timeframe when we had the license issued to us. So
25 everything that you see here is considered

1 preconstruction activities, so all of this work can be
2 done without a license.

3 So what you can see here is that we've got an
4 excavation for Unit 2 on the left. We've got an
5 excavation for Unit 3 on the right. And in the center
6 is a large derrick that we call a heavy-lift derrick.
7 We'll show some more pictures of that in a few minutes.
8 You can see a module assembly building, which is about a
9 120-foot-tall building about the size of a -- footprint
10 of about a football field. That's where we're going to
11 be assembling the modules so that we can get out of the
12 weather. And you can also see a brown bowl-like
13 structure, which is the lower portion of the containment
14 vessel, on the lower right. Our containment vessel is
15 made of 1½-inch-thick steel. It's a large cylinder.
16 And you build it in segments. So the first segment you
17 build is the lower bowl, which you can see being
18 fabricated here. After the lower bowl is fabricated, we
19 then start fabricating rings. The rings will be lifted
20 onto the lower bowl section once it's put in the
21 excavation, and then welded together. You can also see
22 some support structures here, the foundations for the
23 cooling towers, and then just a corner of the
24 switchyard. And I'll show you a little bit more of the
25 switchyard in just a few minutes.

1 [Reference: Hearing Exhibit 1 / {Amended} SAB-
2 1, Pg 10-of-44]

3 This is just a different aerial view. It does show
4 that the contractor parking lot is fairly full. It also
5 shows our two concrete batch plants. We have two
6 because, once you get into the protracted continuous
7 pours, you don't want to stop. So each one of them
8 would be capable of supplying all of our needs, but we
9 do have two.

10 [Reference: Hearing Exhibit 1 / {Amended} SAB-
11 1, Pg 11-of-44]

12 We did need the 404 wetlands permit that I said
13 we'd get the same day as our Combined Operating License,
14 in order to fill in this portion of the property to
15 construct the 2B cooling tower. We'd actually started
16 construction of the other three cooling towers, but 2B
17 was delayed because of the wetlands permit. That's now
18 in hand and the filling of this property is underway.

19 [Reference: Hearing Exhibit 1 / {Amended} SAB-
20 1, Pg 12-of-44]

21 This is that lower bowl. Chicago Bridge & Iron is
22 the company that is fabricating this, doing the welding
23 on this. They are finished and they've turned it back
24 over to Shaw.

25 [Reference: Hearing Exhibit 1 / {Amended} SAB-

1 1, Pg 13-of-44]

2 Once the lower bowl goes in the excavation, it has
3 to sit on something, and this is a module called CR-10,
4 which basically is the foundation for that lower bowl.
5 It will be bolted -- the lower bowl will be bolted to
6 this, and then we'll flow concrete around the structural
7 steel that you see here, and it will become a part of
8 the foundation.

9 [Reference: Hearing Exhibit 1 / {Amended} SAB-
10 1, Pg 14-of-44]

11 This shot was taken from the derrick, and you can
12 see that the CR-10 module is nearing completion. And
13 you can see the basin for one of the cooling towers in
14 the foreground.

15 [Reference: Hearing Exhibit 1 / {Amended} SAB-
16 1, Pg 15-of-44]

17 This again is the CR-10 module, and you can see the
18 plates that we'll bolt the lower bowl to.

19 [Reference: Hearing Exhibit 1 / {Amended} SAB-
20 1, Pg 16-of-44]

21 This is inside of the module assembly building, and
22 these are some mockups of a couple of the modules. This
23 allowed us to do practice with the automated welding
24 techniques inside of this building. That worked out
25 very well. We've since taken these mockups down.

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1 [Reference: Hearing Exhibit 1 / {Amended} SAB-
2 1, Pg 17-of-44]

3 And these are actual segments for the first big
4 module that we'll need, a module called CA-20. So you
5 can see these have been installed on a steel base called
6 the platen and have been tacked in place, and eventually
7 we will have received 72 different subassemblies for the
8 CA-20 module. Many of them are almost 70 feet long.

9 [Reference: Hearing Exhibit 1 / {Amended} SAB-
10 1, Pg 18-of-44]

11 Another view from the crane, you can see the Unit 3
12 excavation to the left, the containment vessel lower
13 bowl in the background. You can just make out, if you
14 look through the crane, the lower ring. But I'll show
15 you another picture of that in a minute. And we also
16 have some test blocks that are large, concrete, and they
17 are attached to the bottom of the heavy-lift derrick.

18 [Reference: Hearing Exhibit 1 / {Amended} SAB-
19 1, Pg 19-of-44]

20 Containment vessel ring: You can see that we've
21 completed the lower bowl and we started on the first
22 ring section. This is one course of steel that has been
23 basically welded into a large ring. When this ring is
24 completed, it will have three courses, so it will be
25 three times this height.

1 [Reference: Hearing Exhibit 1 / {Amended} SAB-
2 1, Pg 20-of-44]

3 This is another shot of that ring, and here we've
4 got the openings in the ring for the personnel hatch and
5 the equipment hatch. So the large circle is where the
6 equipment hatch will go, so you can get equipment in and
7 out of the containment vessel.

8 [Reference: Hearing Exhibit 1 / {Amended} SAB-
9 1, Pg 21-of-44]

10 This is how the excavation looked at the time when
11 we got our license issued to us, so we had not done
12 anything in the excavation. So one of the questions
13 was, "What could you not do?" Well, we're allowed to
14 excavate, but we were not allowed to pour any permanent
15 structures inside. So we framed it, but we had to wait
16 on the license to actually do any of the concrete pours.

17 [Reference: Hearing Exhibit 1 / {Amended}
18 SAB-1, Pg 22-of-44]

19 First thing you do is called dental concrete, so
20 you're kind of filling in cavities, which is why they
21 call it dental concrete. Core bores also would go
22 through here, much deeper than the lower section of the
23 concrete, or the granite here, so you have to fill those
24 in with a high-pressure grout also. So this is called
25 dental concrete, so that's prepping the surface.

1 [Reference: Hearing Exhibit 1 / {Amended} SAB-
2 1, Pg 23-of-44]

3 Next thing you do is you level it. And, obviously,
4 the leveling mat is going to be different heights based
5 on the different areas of the excavation and how deep it
6 is. What you can see here is leveling concrete, which
7 we do in lifts, so it's not one continuous pour. It's
8 over 20 feet thick in some sections, so you do it in
9 roughly 18-inch lifts. This is all under the nuclear
10 side of the plant, and so the contractor has opted to do
11 it in different stages -- you can see the different
12 heights -- to account for the fact that we did have
13 those unanticipated rock conditions under the nuclear
14 island for Unit 2.

15 [Reference: Hearing Exhibit 1 / {Amended} SAB-
16 1, Pg 24-of-44]

17 All right. So here you can see, after the leveling
18 mat is poured, we'll put down what's called a mudmat.
19 On top of the lower mudmat, we'll put a waterproof
20 membrane, which is in black here, you can see. And then
21 on top of the waterproof membrane, when it's finished,
22 we pour an upper mudmat, which is about another six
23 inches of high-strength concrete. So we are finished
24 with this portion, currently.

25 [Reference: Hearing Exhibit 1 / {Amended} SAB-

1 1, Pg 25-of-44]

2 This is the excavation for Unit 3. You can see
3 what it looks like. We're complete on the nuclear
4 island side, with blasting, and we're still working a
5 little bit on the turbine island side, which would be in
6 the background. The Nuclear Regulatory Commission has
7 already come in and done their inspections on the
8 excavation.

9 [Reference: Hearing Exhibit 1 / {Amended} SAB-
10 1, Pg 26-of-44]

11 Once we get the upper mudmat poured, then we'll go
12 in with our reinforcing bar, or rebar, which will hold
13 together the basemat. This is about a six-foot-thick
14 rebar cage. We fabricated it outside of the excavation
15 and lifted it, with the heavy-lift derrick, in place.
16 We had two of these, a north and south.

17 [Reference: Hearing Exhibit 1 / {Amended} SAB-
18 1, Pg 27-of-44]

19 This is the -- so the mudmat here is complete in
20 the excavation --

21 [Reference: Hearing Exhibit 1 / {Amended} SAB-
22 1, Pg 28-of-44]

23 -- and you can see the north and south rebar cages
24 have been placed. And then we'll stick-build the
25 portions in the middle. So this is also nearing

1 completion.

2 [Reference: Hearing Exhibit 1 / {Amended} SAB-
3 1, Pg 29-of-44]

4 We have started to receive a number of large
5 components from overseas, in through the Port of
6 Charleston. These are condenser sections that have come
7 in by ship into the Port of Charleston and transferred
8 to rail.

9 [Reference: Hearing Exhibit 1 / {Amended} SAB-
10 1, Pg 30-of-44]

11 This is the same components arriving at the site.

12 [Reference: Hearing Exhibit 1 / {Amended} SAB-
13 1, Pg 31-of-44]

14 And these are some of those same components being
15 welded together at the site, outside the excavation.
16 And when complete, after the basemat is poured, we'll
17 use the heavy-lift derrick to put those in place.

18 [Reference: Hearing Exhibit 1 / {Amended} SAB-
19 1, Pg 32-of-44]

20 This is underneath the turbine building side of the
21 excavation, so this we would call the turbine island.
22 This is circulating water pipe, which will carry water
23 from the plant proper over to the cooling towers, and
24 then back again.

25 [Reference: Hearing Exhibit 1 / {Amended} SAB-

1 1, Pg 33-of-44]

2 And this is after flowable fill has been poured
3 around those same pipes. This is basically the same
4 picture a little later. The flowable fill just holds it
5 in place; it's like concrete.

6 [Reference: Hearing Exhibit 1 / {Amended} SAB-
7 1, Pg 34-of-44]

8 This is buried piping going between the plant and
9 the cooling towers.

10 [Reference: Hearing Exhibit 1 / {Amended} SAB-
11 1, Pg 35-of-44]

12 This is our switchyard. It's in excess of 30
13 acres. It has nine lines that connect it off-site and
14 three lines that connect it to the Unit 1 switchyard.
15 So the Unit 2-3 switchyard, which you're seeing here, is
16 connected by three lines to our Unit 1 switchyard.

17 This is also nearing completion, and we would
18 anticipate energizing the switchyard about sometime late
19 first quarter of next year.

20 [Reference: Hearing Exhibit 1 / {Amended} SAB-
21 1, Pg 36-of-44]

22 You can see some of the circuit breakers that are
23 being put in by the contractor called Pike Electric.

24 [Reference: Hearing Exhibit 1 / {Amended} SAB-
25 1, Pg 37-of-44]

1 This is Pike connecting some of the 230,000-volt
2 lines from off-site to the Unit 2-3 switchyard.

3 [Reference: Hearing Exhibit 1 / {Amended} SAB-
4 1, Pg 38-of-44]

5 This just shows how they have to actually exit a
6 105-foot bucket truck to get up to some of the lines
7 that they have to pull.

8 [Reference: Hearing Exhibit 1 / {Amended} SAB-
9 1, Pg 39-of-44]

10 And this is connecting between the Unit 1
11 switchyard and the Unit 2-3 switchyard.

12 [Reference: Hearing Exhibit 1 / {Amended} SAB-
13 1, Pg 40-of-44]

14 This is some of the lines going off-site on an
15 existing right-of-way.

16 [Reference: Hearing Exhibit 1 / {Amended} SAB-
17 1, Pg 41-of-44]

18 Simulator. This is our simulator. We have two of
19 them at the site now. These simulators are up and
20 running, and we are actually running scenarios and
21 training people on them today.

22 [Reference: Hearing Exhibit 1 / {Amended} SAB-
23 1, Pg 42-of-44]

24 I said I'd show you a few more pictures of the
25 heavy-lift derrick. You can see that it's a twin-

1 derrick design. It travels on a rail, 360 degrees, in
2 circles. So it's not mobile but it does rotate in a
3 circle. It goes right between the units, and its 560-
4 foot-long front boom can reach either unit. It's
5 tethered to a counterweight at the back through that
6 long, blue, tension column, where we have a 6,000-ton
7 counterweight buried, and it has a universal joint that
8 allows it to rotate.

9 [Reference: Hearing Exhibit 1 / {Amended} SAB-
10 1, Pg 43-of-44]

11 Just to give you some perspective, I've circled a
12 school bus which is about a quarter mile in front of the
13 heavy-lift derrick. So it is truly a BIGGE crane. The
14 BIGGE Corporation, not really the name of the crane.

15 [Reference: Hearing Exhibit 1 / {Amended} SAB-
16 1, Pg 44-of-44]

17 And we continue to be involved with the Chinese
18 construction projects. This is Sanmen Unit 1 in the
19 foreground and 2 in the background. This picture is
20 probably dated by six or eight months, and they're
21 making great progress at Sanmen. Our sites are going to
22 look a lot like their sites, so we find a lot of that's
23 been -- making trips there and entertaining some of
24 their folks here, so we can have a collaborative
25 relationship, not just with Sanmen but the other

1 construction site at Haiyang.

2 [Indicating.] As of May 15, 2012, 72 milestones,
3 or 49 percent, of 146 total milestones have been
4 completed. In addition, of the remaining 74 uncompleted
5 milestones, 12 completion dates have been accelerated;
6 47, or 32 percent, have been delayed between 1 and 16
7 months; and the remaining 15 uncompleted milestones are
8 unchanged.

9 As of June, there were a total of approximately
10 1,400 craft and professional personnel working at the
11 site for Westinghouse, Shaw, or other contractors, and
12 217 personnel from SCE&G, Santee Cooper, and SCANA's New
13 Nuclear group.

14 As of May 2012, Shaw had 28 primary subcontractors
15 working at the site; 14 of these primary subcontractors,
16 or 50 percent, were South Carolina based companies.
17 These primary subcontractors were utilizing a total of
18 28 sub-tier contractors; 17 of those, or approximately
19 61 percent, are also based in South Carolina. In
20 addition, Shaw has 645 direct craft working at the site;
21 of these, 392, or 61 percent, were from South Carolina.

22 SCE&G and Westinghouse/Shaw are very proud of the
23 current safety record at the site. We've worked over
24 5.4 million man-hours on-site with only a minimal number
25 of lost-time accidents. This is a remarkable testimony

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PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1 to the care and professionalism with which all parties
2 are approaching work on these units with respect to
3 safety.

4 As I have mentioned in past testimony, apart from
5 our enduring -- from the enduring safety of our people
6 and the public, the company has no greater priority than
7 getting the deployment of the new nuclear units right.
8 Doing so requires the company to put in place a team of
9 people that are capable of overseeing the work of scores
10 of on-site contractors and subcontractors. They also
11 oversee a worldwide supply chain for highly specialized
12 components and equipment, and the transportation and
13 logistics required to bring those components and
14 equipment safely together in Jenkinsville. All of this
15 must be done while recruiting and training a permanent
16 staff that can operate and maintain the units safely and
17 efficiently when they go into service. That same staff
18 must also successfully conduct the acceptance testing
19 that the Nuclear Regulatory Commission requires before
20 the units are put into commercial operation.

21 An important part of this effort is cost control.
22 We take cost control very seriously. The senior
23 leadership for the project takes an active role in
24 reviewing budgets, setting up systems, and engaging
25 staff appropriately to ensure that only necessary and

1 prudent costs are included in cost forecasts. Our cost
2 and staffing reviews are thorough and demanding. We
3 will not jeopardize the safety or quality of the
4 project; by the same token, we will not tolerate
5 unnecessary spending.

6 In addition, since March 30, 2012, SCE&G has been
7 managing the project under an active NRC Nuclear
8 Construction and Operating License issued in its name.
9 As the NRC is quick to remind us, the company is now
10 directly responsible to the NRC for the safety of the
11 units as constructed. SCE&G is also responsible for
12 quality assurance and quality control both on-site and
13 in the shops and factories where components are being
14 fabricated worldwide.

15 These units will serve as a critical component of
16 our generation portfolio for decades. They are expected
17 to serve the needs of our customers for 60 years. With
18 those facts in mind, SCE&G is committed to continuously
19 monitor the needs of the project and to adjust its
20 staffing, training, and resource plans whenever it
21 concludes that doing so is necessary to protect the
22 interests of the company and its customers in the
23 project.

24 As Ms. Walker testifies, updates in owners' cost
25 forecasts represent \$131.6 million of the \$283 million

1 that we are requesting here for BLRA approval. These
2 costs are the reasonable and necessary costs of
3 fulfilling our responsibilities as owners of the
4 project. It is my opinion that the adjustments in the
5 forecasts of owners' costs for the new nuclear project
6 are reasonable and prudent costs of the units. These
7 costs reflect a valuable investment that the company is
8 making to protect its interests and those of its
9 customers, as well as those of our partner, Santee
10 Cooper, in the project.

11 SCE&G is also presenting a total of four change
12 orders to the EPC contract for review in this
13 proceeding. One of them, Change Order No. 16, is
14 basically an agreement between SCE&G and
15 Westinghouse/Shaw that resolves claims by
16 Westinghouse/Shaw for recognition of additional costs
17 associated with four things: First is a redesign of the
18 shield building for the AP1000 units, to increase its
19 resistance to aircraft impact; second is the
20 rescheduling of construction plans for the units, to
21 take into account the approximately nine-month delay in
22 the issuance of the COL; third includes changes to the
23 design of the structural modules for the project, using
24 higher strength steel than was originally specified,
25 among other changes; and the fourth involves responding

1 to unanticipated rock conditions at the foundation of
2 Unit 2. This agreement formed part of the basis on
3 which SCE&G issued a full notice to proceed with the
4 project earlier this year.

5 Change Order No. 16 represents \$137.5 million, or
6 slightly less than half, of the total change in the
7 forecasted costs being presented for review here. As
8 detailed in my testimony, SCE&G carefully evaluated the
9 legal and factual basis for each of the claims and the
10 documentation of costs, as part of its negotiations.
11 Through its review and negotiations, SCE&G was able to
12 reduce the Westinghouse/Shaw initial claim of \$213.6
13 million by about \$92 million. As part of the analysis
14 and review related to Change Order No. 16, we agreed to
15 adopt a new substantial completion date that better
16 coordinated the construction schedules for the two
17 units. This created a savings of about \$15.9 million
18 due to increased efficiencies. The schedule delays the
19 completion date of Unit 2 but accelerates the completion
20 of the project as a whole by seven and a half months.

21 Based on my knowledge of the facts and my
22 experience in the industry, I believe that the
23 resolution of these claims was fair, reasonable, and
24 prudent, and supports the best interests of the company
25 and its customers. It reflects a far better outcome

1 than protracted, divisive, and expensive litigation
2 during the construction process.

3 The other three change orders under review here are
4 Change Orders Nos. 12, 14, and 15. They concern
5 additional costs for compliance with new federal
6 healthcare mandates, cybersecurity, and the minor
7 redesign of the wastewater piping system, respectively,
8 and totals \$6 million, with cybersecurity costs
9 representing more than 95 percent of that amount.

10 Apart from the change orders presented here, SCE&G
11 has negotiated a total of 11 change orders to the EPC
12 contract since 2008. Only five of them involve
13 substantive changes in scope of work. These five change
14 orders have had a total collective value of about \$1.5
15 million.

16 I also sponsor Exhibit No. SAB-3, which is an
17 updated version of the construction milestone schedule
18 for the units. It reflects the new substantial
19 completion dates for Units 2 and 3, which are March 15
20 of 2017 and May 15 of 2018, respectively.

21 The reason for the changes in the substantial
22 completion dates for the units relates to matters that
23 are not unexpected in construction projects of this size
24 and complexity. In addition, under the new schedule,
25 Unit 2 will be placed in service well within its

1 original 18-month schedule contingency. The substantial
2 completion date for Unit 3 will be advanced by seven and
3 a half months. Completion of the units on this schedule
4 will permit the timely retirement of 730 megawatts of
5 coal-fired capacity. That capacity is in existing units
6 that are too small to be brought up to increasingly
7 stringent emissions standards in a cost-effective way.
8 Advancing Unit 3's substantial completion date will
9 allow for the acceleration of this retirement plan.

10 For all these reasons, the updated milestone
11 schedule represents a reasonable and prudent schedule
12 for the completion of the project. It reflects
13 necessary changes that are not the result of any failure
14 of the company to diligently and prudently manage the
15 project. We have six years left in this project, and
16 further changes are not unlikely. In this proceeding,
17 we are putting before the Commission and the public all
18 of the cost and schedule changes that we have identified
19 to date. Our commitment is to manage the cost of this
20 project carefully and to put before the Commission the
21 changes and costs as they are identified.

22 As president for Generation and Transmission, I am
23 involved on an ongoing basis with all major aspects of
24 the construction project. The adjustments requested in
25 this proceeding are adjustments that I know to represent

1 reasonable and prudent changes in the costs and
2 construction schedules for the units. In my
3 professional opinion, the adjustments are the result of
4 the normal and expected evolution of a project of this
5 size and scope. I ask that the Commission approve these
6 adjustments as presented.

7 MR. ZEIGLER: Thank you, Mr. Byrne.
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22 [PURSUANT TO PREVIOUS INSTRUCTION, THE
23 PREFILED DIRECT TESTIMONY {W/CORRECTION} OF
24 STEPHEN A. BYRNE {PUBLIC VERSION} FOLLOWS
25 AT PGS 170-214]

DIRECT TESTIMONY OF**STEPHEN A. BYRNE****ON BEHALF OF****SOUTH CAROLINA ELECTRIC & GAS COMPANY****DOCKET NO. 2012-203-E**

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Stephen A. Byrne and my business address is 220 Operation Way, Cayce, South Carolina. I am President for Generation and Transmission of South Carolina Electric & Gas Company ("SCE&G" or the "Company").

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I have a Chemical Engineering degree from Wayne State University. After graduation, I started my nuclear career working for the Toledo Edison Company at the Davis-Besse Nuclear Plant. I was granted a Senior Reactor Operator License by the Nuclear Regulatory Commission ("NRC") in 1987. From 1984 to 1995, I held the positions of Shift Technical Advisor, Control Room Supervisor, Shift Manager, Electrical Maintenance Superintendent, Instrument and Controls Maintenance Superintendent, and Operations Manager. I began working for SCE&G in 1995 as the Plant Manager at the V. C. Summer plant. Thereafter, I was promoted to Vice President and Chief Nuclear Officer. In 2004, I was

1 promoted to the position of Senior Vice President for Generation, Nuclear and
2 Fossil Hydro. I was promoted to the position of Executive Vice President for
3 Generation in 2008 and to Executive Vice President for Generation and
4 Transmission in early 2011. I was promoted to President for Generation and
5 Transmission and Chief Operating Officer of SCE&G in 2012.

6 **Q. WHAT ARE YOUR DUTIES WITH SCE&G?**

7 A. As President of Generation and Transmission and Chief Operating Officer
8 for SCE&G, I am in charge of overseeing the generation and transmission of
9 electricity for the Company. I also oversee all nuclear operations. Included in my
10 area of responsibility is the New Nuclear Deployment ("NND") project in which
11 Westinghouse Electric Company and the Shaw Group ("Westinghouse/Shaw") are
12 constructing two Westinghouse AP1000 nuclear generating units in Jenkinsville,
13 South Carolina (the "Units") that are jointly owned by SCE&G and South
14 Carolina Public Service Authority ("Santee Cooper").

15 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?**

16 A. Yes. I have testified before the Public Service Commission of South
17 Carolina (the "Commission") in several past proceedings.

18 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

19 A. The purpose of my testimony is to discuss the current status of construction
20 of the new nuclear units; the agreement between SCE&G and Westinghouse/Shaw
21 resolving EPC Contract claims outstanding in March of 2012; the three other EPC

1 Contract change orders at issue in this proceeding; and the operational, contractual
2 and other matters related to the updates to the cost schedules proposed in this
3 proceeding. This testimony is also submitted in satisfaction of the requirement
4 imposed by the Commission in Order 2009-104(A) that the Company provides
5 annual status reports concerning its progress in constructing the Units.

6 **PROJECT UPDATE**

7 **Q. PLEASE PROVIDE AN OVERVIEW OF THE PROJECT STATUS.**

8 A. I would characterize the current status of project by saying that most of the
9 site discovery work is now complete. By that I mean that every construction site
10 has conditions that are not apparent until a substantial body of work has been done
11 on the project. An important part of every project is discovering any unanticipated
12 conditions and responding to them. The same is true concerning the construction
13 team and supply chain for each major project. I believe that we are now largely
14 out of the discovery phase for this project. We know the site and its conditions.
15 We know Westinghouse/Shaw and how we must work with them to be effective.
16 We know the supply chain. The major procurement orders for the project have
17 been placed. Each of the nuclear steam supply system components for an AP1000
18 Unit has been fabricated successfully at least once, and in some cases several
19 times over. Much of the major equipment for Unit 2 is either in the final stages of
20 manufacture or is finished. Material procurement is largely complete for the
21 major equipment for Unit 3.

1 **Q. WHAT ABOUT LICENSING AND PERMITTING?**

2 A. We received our Combined Operating License ("COL") from the NRC on
3 March 30, 2012, and our Clean Water Act Section 404 wetland permit the same
4 day. We received our Clean Water Act Section 401 certification on December 16,
5 2011. We are awaiting final action on the permits for our wastewater systems and
6 discharge systems. We anticipate receiving these permits soon. Additional
7 construction permits will be obtained as required.

8 **Q. PLEASE DESCRIBE THE STATUS OF THE ON-SITE CONSTRUCTION**
9 **ACTIVITIES RELATED TO THE UNITS.**

10 A. On April, 3 2012, Westinghouse/Shaw began placing nuclear safety-related
11 concrete for the foundation of the Unit 2 power block. This is dental concrete
12 which is the concrete placed over the underlying rock and forms the basis for the
13 leveling concrete over which is poured the layer of concrete called the mud mat.
14 The base mat for the Unit is placed over the mud mat. As of July 20, 2012,
15 Westinghouse/Shaw had placed 13,765 cubic yards of concrete for the Unit 2
16 nuclear island and 10,472 cubic yards of concrete for the turbine building.

17 Westinghouse/Shaw and their contractors are in the early stages of
18 assembling the framework of steel reinforcing bar (rebar) for the base-mat of the
19 nuclear island. The assembly was proceeding using a technique for terminating
20 the floor rebar at the wall connection using "T" joints. This construction
21 technique is well accepted in the industry. However, in inspecting similar work at

1 the Vogtle site, NRC inspectors took the position that the technique being used
2 was not the technique envisioned by the relevant drawings in the Design Control
3 Document ("DCD") and was not in compliance with those drawings. In response,
4 SCE&G entered this issue into our corrective action program.
5 Westinghouse/Shaw has disassembled the work done using the earlier technique
6 and is proceeding with construction using the alternative approach shown in the
7 drawings. This is an area of focus for the schedule and Shaw is assessing the
8 schedule impact.

9 The ~~geotechnical~~^{waterproof} membrane that will form a moisture barrier for the Unit 2
10 mud mat is being prepared for installation and as of July 20, 2012 approximately
11 three quarters of it was in place. Concrete is being placed for the foundations of
12 the Unit 2 Turbine building. Engineered backfill is being placed around the Unit 2
13 Nuclear Island and Turbine Building.

14 Excavation of the nuclear island footprint for Unit 3 was complete as of
15 July 2012 and geological mapping of the area is underway and progressing well.

16 The Bigge Heavy Lift Derrick (the "HLD"), which is the principal
17 construction crane for the Units, is now assembled and has completed successful
18 load testing and has been used in off-loading turbine generator condenser
19 components into storage. The HLD has a lifting capacity of 7,500 tons and a
20 boom length of 565 feet.

1 Several shipments of floor and wall assemblies for the CA-20 Structural
2 Module have arrived on site and are being fitted up in preparation for welding in
3 the Module Assembly Building (the "MAB"). Module CA-20, which is the first
4 large module to be installed in the auxiliary building, is a seven-story unit that will
5 house the fuel transfer canal, the fuel pool, several demineralizers and other major
6 components of the auxiliary building.

7 Over 800 sections of Circulating Water System ("CWS") pipe have been in
8 place for some time. More recently, additional sections were placed below the
9 Turbine Building for Unit 2. Additional CWS pipe has also been placed in the
10 areas where the CWS will tie into the cooling towers.

11 The basin and related structures for Cooling Tower 2A are complete and
12 Shaw has turned Cooling Tower 2A over to their subcontractor Evaptech, Inc. for
13 construction of the cooling tower itself. Shaw has substantially completed the
14 basins for Cooling Towers 3A and 3B and is finalizing structural elements in
15 anticipation of turning the work over to Evaptech.

16 Subcontractor Chicago Bridge & Iron ("CB&I") has completed fabrication
17 of the first major component of the containment vessel. This is the containment
18 vessel bottom head which forms the bottom bowl of the containment vessel. The
19 containment vessel bottom head has been turned over to Shaw to attach sections of
20 rebar prior to lifting and placing it in the Unit 2 nuclear island. Fit-up work has

1 begun on the first of the rings (Ring 1) that attach to the bottom head and will form
2 the vertical walls of the containment vessel when installed.

3 The switchyard for these Units is on schedule to be completed in early
4 2013. Foundation work was substantially completed in mid-2011 and Shaw turned
5 the site over to Pike Electric for installing structures and interconnecting electrical
6 equipment. All structures are now complete. Most breakers and major equipment
7 have now been installed. Pike is working on control cable installation and relay
8 testing. When this work is finished, the Switchyard will be complete. Early in the
9 project, SCE&G identified training control room operators as a critical path item
10 for the project. By Change Order No. 2, SCE&G added limited scope simulators to
11 the project to allow the training of control room operators to be accelerated. As of
12 June 30, 2012, both the Unit 2 and Unit 3 limited scope simulators have been
13 installed and turned over to the NND training team. This group is testing the
14 simulators by running simulations and scenarios on them in anticipation of
15 conducting operator training exercises in the near future. The simulator control
16 rooms are exact copies of the future control rooms for the Units as presently
17 designed.

18 **Q. WHAT IS THE CURRENT STATUS OF EQUIPMENT**
19 **MANUFACTURING AND FABRICATION?**

20 **A.** Manufacturing is ongoing for the Unit 2 and 3 Reactor Vessel and Steam
21 Generator components. In mid-2012, manufacturing for the Unit 2 components

1 was in the final stages of completion and manufacturing work on Unit 3
2 components was starting. This work is taking place at the Doosan facility in South
3 Korea.

4 Manufacturing of the Unit 2 Reactor Coolant Loop Piping has been
5 completed by IBF (a subcontractor of Tioga) at its facilities in Italy and these
6 components have been shipped to the United States. The surge lines were shipped
7 directly to the site. The hot and cold legs were shipped to the Carolina Energy
8 Solutions ("CES") facility in Rock Hill, South Carolina where installation of
9 fittings will take place. The production of Unit 3 Reactor Coolant Loop Piping is
10 in process.

11 The lead Reactor Coolant Pump being produced in Pennsylvania by the
12 Electro-Mechanical Division ("EMD") of Curtiss-Wright Corp. for the AP1000
13 design has successfully completed testing. SCE&G-specific pumps are in active
14 manufacturing.

15 The manufacturing of the Unit 2 Core Make-Up Tanks, Pressurizer,
16 Accumulators, and Passive Residual Heat Removal ("PRHR") Exchanger were
17 under active manufacture at Mangiarotti's facility in Italy. This work was initially
18 delayed due to issues related to Mangiarotti's suppliers who were having difficulty
19 in adopting effective quality assurance and quality control ("QA/QC") programs
20 that meet nuclear safety standards, and were also experiencing work scheduling
21 issues. These matters were resolved but recently the manufacture of Core Make-

1 Up tanks has been delayed due to a change in the design. These manufacturing
2 delays are not anticipated to affect the construction schedule since the shipment
3 dates for the Core Make-Up tanks are well in advance of the requirements of the
4 construction schedule.

5 The turbine generator is under manufacture at the Toshiba facility in Japan
6 and proceeding smoothly. The Fukushima event has not delayed any of our
7 Japanese manufacturing activities.

8 In all, as of May 15, 2012, 72 milestones (49%) of the 146 total milestones
9 have been completed. In addition, of the remaining 74 uncompleted milestones,
10 12 milestone completion dates have been accelerated. Forty-seven (32%) have
11 been delayed between one and 16 months. The remaining 15 uncompleted
12 milestones are unchanged. These milestone dates will be updated on a quarterly
13 basis as information is received from Westinghouse/Shaw and reviewed by our
14 project team.

15 **Q. ARE ANY MILESTONES DELAYED BY 16 MONTHS OR MORE?**

16 A. Yes. For the reasons stated above, Milestone 61 related to the hydrostatic
17 testing of the Core Make-Up Tank has been delayed by 16 months. But for the
18 reasons discussed above, we do not anticipate these manufacturing and testing
19 delays to impact any critical-path construction activities.

20

1 Q. DO YOU HAVE PHOTOGRAPHS OR SLIDES THAT ILLUSTRATE
2 YOUR TESTIMONY?

3 A. Yes. They are attached to my testimony as Exhibit No. 1 (SAB-1).

4 Q. WHAT IS THE CURRENT STATE OF WORK ON TRANSMISSION
5 PROJECTS FOR THE UNITS?

6 A. Mr. Young will provide this information in his testimony.

7 Q. HOW MANY PEOPLE ARE CURRENTLY EMPLOYED AT THE
8 JENKINSVILLE SITE?

9 A. As of June 2012, there were a total of approximately 1,377 craft and
10 professional personnel working at the site for Westinghouse/Shaw or other
11 contractors and approximately 217 personnel from SCE&G, Santee Cooper and
12 SCANA's new nuclear groups.

13 As of May 2012, Shaw had 28 primary subcontractors working at the site.
14 Fourteen of these primary subcontractors (50% of the total) were South Carolina-
15 based companies. These primary subcontractors were utilizing a total of 28 sub-
16 tier contractors, 17 of which (approximately 61%) are also based in South
17 Carolina. In addition, in May 2012, Shaw had 645 direct craft employees working
18 at the site. Of them, 392 or 61% are from South Carolina.

19 SCE&G and Westinghouse/Shaw are very proud of the current safety
20 record at the site. We have worked over 5.4 million man hours on the site with
21 only a minimal number of lost time accidents. This is remarkable testimony to the

1 care and professionalism with which all parties are approaching work on these
2 Units with respect to safety.

3 **COST CATEGORIES FOR THE PROJECT**

4 **Q. PLEASE DESCRIBE HOW THE VARIOUS COSTS ASSOCIATED WITH**
5 **THE UNITS ARE CATEGORIZED.**

6 A. In Order No. 2009-104(A), the Commission reviewed and approved
7 SCE&G's estimate of forecasted costs for the Units as shown in nine cost
8 categories. Seven of these cost categories reflected costs agreed to in the
9 Engineering, Procurement, and Construction Agreement (the "EPC Contract").
10 Four of those seven involve categories of fixed cost, which do not change, or firm
11 costs which change only based on specified inflation indices ("Fixed/Firm Costs").
12 Two of the seven EPC categories involve costs where Westinghouse/Shaw
13 operates under established budgetary targets and SCE&G pays actual costs as
14 incurred ("Target Costs"). The seventh is time and materials which are costs for
15 allowances requiring pre-approval by SCE&G for things like start-up, scaffolding,
16 and licensing support. The final two cost categories are Transmission costs and
17 Owners cost. These are activities that SCE&G undertakes directly and are outside
18 of the scope of work of the EPC Contract with Westinghouse/Shaw.

- 19 • Transmission cost includes the cost of the transmission facilities that
20 SCE&G will build to integrate the Units into its transmission grid.

1 • Owners cost include the costs of the NND teams and associated costs,
2 and involve such things as site-specific licensing and permitting of the
3 Units and their construction; regulatory costs such as NRC fees; insurance,
4 including workers compensation insurance for all workers on site, builder's
5 risk insurance and transportation risk insurance; construction oversight and
6 contract administration costs; the costs of recruiting and training of
7 operating personnel for the Units; the costs of overseeing the final
8 acceptance testing of the Units and providing for interim maintenance of
9 components of the Units as completed; the cost of facilities, information
10 technology systems and equipment to support the project and the permanent
11 staff of the Units, and other incidental costs such as sales taxes and utilities
12 for the site.

OWNERS COST AND THE NND PROJECT

14 **Q. WHAT IS THE COMPANY'S PHILOSOPHY CONCERNING THE NND**
15 **PROJECT?**

16 **A.** As I have mentioned in past testimony, apart from ensuring the safety of
17 our people and the public, the Company has no greater priority than getting the
18 deployment of the new nuclear Units right. Doing so requires the Company to put
19 in place a team of people that are capable of overseeing the work of scores of on-
20 site contractors and subcontractors, a worldwide supply chain for highly
21 specialized components and equipment, and the transportation and logistics

1 required to bring those components and equipment safely together in Jenkinsville.
2 All this must be done while recruiting and training a permanent staff that can
3 operate and maintain the Units safely and efficiently when they go into service,
4 and that can successfully conduct the acceptance testing that the NRC requires
5 before the Units are put into commercial operation. Getting new nuclear
6 deployment right also requires SCE&G to keep in place a team of people who can
7 ensure that the contractual aspects of the project are prudently managed, that the
8 terms of the EPC Contract are enforced, and that we do all in our power to ensure
9 that costs are controlled.

10 **Q. DO YOU TAKE COST CONTROL SERIOUSLY?**

11 A. We take cost control very seriously. Senior leadership for the project takes
12 an active role in reviewing budgets, setting up systems, and engaging staff
13 appropriately to ensure that only reasonable, necessary and prudent costs are
14 included in the cost forecasts. Our cost and staffing reviews are thorough and
15 demanding. We will not jeopardize the safety or quality of the project, but by the
16 same token, we will not tolerate unnecessary spending.

17 **Q. UNDER THE EPC CONTRACT, WHAT ROLE DOES SCE&G PLAY IN**
18 **THE LICENSING AND PERMITTING OF THE UNITS?**

19 A. Apart from the DCD for the AP1000 reactor, SCE&G is responsible for
20 obtaining the major licenses and permits that are required to construct and operate
21 the Units. Also, during construction and testing of the Units, SCE&G must ensure

1 that it and its contractors comply with all terms and conditions of these licenses
2 and permits.

3 **Q. HOW DOES THE NRC SEE SCE&G'S CURRENT RESPONSIBILITIES**
4 **AS OWNER AND LICENSE HOLDER?**

5 A. Since March 30, 2012, SCE&G has been managing the project under an
6 active NRC nuclear construction and operation license issued in SCE&G's name.
7 As the NRC is quick to remind us, the Company is now directly responsible to the
8 NRC for the safety of the Units as constructed and for QA/QC both on-site and in
9 the shops and factories where components are being fabricated worldwide.

10 **Q. WHAT RESPONSIBILITY DOES SCE&G HAVE FOR THE**
11 **TRANSMISSION ASSETS REQUIRED TO SUPPORT THE UNITS?**

12 A. As the recipient of power from the Units, SCE&G must design, site, permit
13 and construct the transmission facilities necessary to route SCE&G's share of the
14 power from these Units to its customers. Those transmission facilities must be
15 operational in time to support the testing of component systems of the Units as
16 those systems are completed and turned over to SCE&G for acceptance testing.

17 **Q. WHAT IS SCE&G'S PHILOSOPHY ABOUT DEPLOYING THE**
18 **RESOURCES REQUIRED TO MEET THESE CHALLENGES?**

19 A. These Units will serve as a critical component of our generation portfolio
20 for decades. They are expected to serve the needs of our customers for 60 years.
21 With those facts in mind, SCE&G is committed to continuously monitor the needs

1 of the project and to adjust its staffing, training and resource plans whenever it
2 concludes that doing so is necessary to protect the interests of the Company and its
3 customers in this project.

4 **Q. HOW DO THESE COMMITMENTS FACTOR INTO THIS**
5 **PROCEEDING?**

6 A. As Ms. Walker testifies, updates in Owners cost forecasts represent \$131.6
7 million¹ of the \$283.0 million that we are presenting here for BLRA approval.
8 These costs are the reasonable and necessary costs of fulfilling our responsibilities
9 as the owner of this project.

10 **Q. WHAT GROUP WITHIN SCE&G IS RESPONSIBLE FOR CARRYING**
11 **OUT THE TASKS YOU HAVE DESCRIBED?**

12 A. The NND teams have direct responsibility for the project. They are
13 supported by resources from throughout SCE&G, SCANA and other SCANA
14 subsidiaries. But the primary responsibility for the success of the project rests
15 with the NND teams.

16 **Q. HOW HAS SCE&G STRUCTURED THE NND TEAMS?**

17 A. The NND teams are comprised of eight groups which include Nuclear
18 Licensing, Design Engineering, Organizational Development and Performance
19 ("OD&P"), Quality Systems, Construction, Business and Finance, Operational

¹ Unless otherwise specified, all cost figures in this testimony are stated in 2007 dollars net of Allowance for Funds Used During Construction and reflect SCE&G's share of the cost of the Units.

1 Readiness and Training. Other groups that share resources with Unit 1 are Health
2 Physics, Emergency Planning, Chemistry, and Security Services. In July of 2012,
3 the staffing of the NND teams was 217 SCANA, SCE&G and Santee Cooper
4 employees. Just before Unit 2 goes into commercial operation in 2017, the
5 staffing level is forecasted to be 675 (excluding security contractors). The
6 permanent staffing for the two Units is expected to be 705 (excluding security
7 contractors). Many of the members of the NND teams will transition to permanent
8 operating staff of the Units, although there will be some retirements and other
9 attrition. The structure of the NND teams and the responsibilities of the eight
10 areas that comprise them are discussed in Mr. Lavigne's testimony and exhibits.

11 **Q. WHAT IS THE EXPERIENCE LEVEL OF THE LEADERS OF THESE**
12 **TEAMS?**

13 A. The members of the senior leadership team for the NND teams have an
14 average of more than 30 years of experience in nuclear and major generating plant
15 construction.

16 The newest member of the team is Ron Jones who joined us this summer as
17 the vice president responsible for this project. Mr. Jones retired from a 31-year
18 career with Duke Energy in December 2011. He most recently served as senior
19 vice president of nuclear development for Duke, where he was responsible for the
20 company's new nuclear generation strategy. Previously, Mr. Jones was senior vice
21 president of nuclear operations for Duke, providing oversight for the safe and

1 reliable operation of Catawba, McGuire and Oconee nuclear stations. He also had
2 responsibility for corporate nuclear engineering and plant support groups. Mr.
3 Jones holds a Bachelor of Science degree in electrical engineering from Virginia
4 Tech. He received his senior reactor operator license from the NRC in 1987. He
5 has held multiple leadership roles in the industry with organizations such as the
6 Nuclear Energy Institute, the Institute of Nuclear Power Operations, the Electric
7 Power Research Institute, and the Carolinas Nuclear Cluster. He will be replacing
8 Ron Clary, who will be retiring after 40 years of service with the Company and
9 who has led this team since 2005.

10 **Q. DO YOU HAVE AN OPINION CONCERNING THE REASONABLENESS**
11 **AND PRUDENCE OF THE ADJUSTMENTS TO THE STAFFING LEVELS**
12 **AND COST SCHEDULES FOR THE NND PROJECT THAT THE**
13 **COMPANY IS PRESENTING HERE?**

14 **A.** For the reasons set forth in this testimony, as well as those set forth in Mr.
15 Lavigne's testimony and Ms. Walker's testimony, it is my opinion that the
16 adjustments in the forecasts of Owners cost for the NND project are reasonable
17 and prudent costs of the Units. These costs reflect a prudent and valuable
18 investment that the Company is making to protect its interests and those of its
19 customers, as well as those of our partner Santee Cooper, in the project.

CHANGE ORDERS

1
2 **Q. PLEASE DISCUSS THE CHANGE ORDERS TO THE EPC CONTRACT**
3 **THAT SCE&G IS PRESENTING FOR APPROVAL IN THIS**
4 **PROCEEDING.**

5 A. SCE&G is presenting a total of four change orders to the EPC Contract for
6 review in this proceeding. One of them, Change Order No. 16, is being prepared
7 for signature and is based on a preliminary agreement reached between SCE&G
8 and Westinghouse/Shaw on March 29, 2012, and a final agreement signed on July
9 11, 2012. Those agreements resolved four major issues that were outstanding
10 between the principal members of project team in March of 2012. This was the
11 time when we were preparing for the COL to be issued and for a decision to be
12 made regarding the timing of issuing the full notice to proceed with the project.
13 The other three change orders are Change Order Nos. 12, 14 and 15. (Change
14 Order No. 13 was a no-cost change to add remote IT work stations for plant
15 operators.) These three change orders concern additional costs for compliance
16 with new federal health care mandates, cyber security, and the minor redesign of a
17 waste water piping system, respectively.

18 **Q. WHAT IS THE COST IMPACT OF THESE CHANGE ORDERS?**

19 A. Change Order No. 16 represents \$137.5 million or slightly less than half of
20 the total change in forecasted costs being presented for review here. The other

1 three change orders collectively represent \$6.0 million of the change in costs, with
2 cyber security representing more than 95% of that amount.

3 **Q. OVER THE LIFE OF THE EPC CONTRACT, WHAT OTHER CHANGE**
4 **ORDERS HAVE BEEN AUTHORIZED?**

5 A. Since 2008, SCE&G has negotiated a total of 11 change orders to the EPC
6 Contract. Six of these change orders resulted in additional costs to the project,
7 four did not and one was superseded. One of these six change orders, Change
8 Order No. 8, did not involve any substantive change to any scope of work under
9 the EPC Contract. Instead, Westinghouse/Shaw's agreed to shift a substantial
10 amount of work from target categories, where SCE&G bears the price risk, to
11 fixed/firm categories where Westinghouse/Shaw bears the principal price risk.
12 The other five change orders did involve substantive changes in the scope of work
13 and have a total collective value of \$1.5 million. Exhibit No. 1 (SAB-2) provides
14 a summary of the details related to the prior change orders. These costs associated
15 with these 11 change orders were presented to the Commission in Docket No.
16 2010-376-E and approved in Order No. 2011-354. They are described in detail in
17 my direct testimony in that docket, which I would incorporate here by reference.

Change Order No. 16

1
2 **Q. PLEASE EXPLAIN THE FACTUAL BACKGROUND OF CHANGE**
3 **ORDER NO. 16.**

4 A. Change Order No. 16 will formalize the agreements entered into among
5 SCE&G, Santee Cooper and Westinghouse/Shaw that resolved claims by
6 Westinghouse/Shaw for recognition of additional costs associated with four
7 things:

- 8 1. The shield building for the AP1000 Unit as it had been redesigned to increase
9 its resistance to aircraft impacts;
- 10 2. Rescheduling the construction plan for the Units to take into account the
11 approximately nine month delay in the issuance of the COL;
- 12 3. The structural modules for the project, as redesigned, using higher strength
13 steel than was originally specified, among other changes; and
- 14 4. Responding to unanticipated rock conditions at the foundation of Unit 2.

15 **Q. HOW DO THESE INDIVIDUAL COMPONENTS OF THE SETTLEMENT**
16 **CONTRIBUTE TO THE \$137.5 MILLION TOTAL?**

17 A. Chart A provides a breakdown of how the four items contribute to the total
18 amount of Change Order No. 16, and show the initial itemized demand made by
19 Westinghouse/Shaw. Westinghouse/Shaw's initial claim was for \$213.6 million
20 and was supported by documentation showing this level of additional cost.
21 Westinghouse/Shaw's initial \$213.6 million claim already reflected \$15.9 million

in savings due to the rescheduling of Unit 3 to create construction efficiencies. But for those savings, the claim would have been \$229.5 million. Based on SCE&G's initial review and challenge of the claim, Westinghouse/Shaw reduced the claim to \$188.0 million. In the end, we reached a settlement at \$137.5 million which is a reduction in the initial claim of \$76.1 million not taking into account the savings due to rescheduling, or \$92.0 million if those savings are included. A breakdown of the costs of Change Order No. 16 according to the different elements it contained is found on the following Chart A:

Chart A

Change Order No. 16 Settlement (Public Version) (millions)						
	COL Delay	Shield Buildi ng	Structural Modules	Unit 2 Rock	Rebate	Total
Westinghouse/ Shaw Initial Proposal						\$213.6
Westinghouse/ Shaw Revised Proposal						\$188.0
Settlement Agreement						\$137.5

1 **Q. WHY IS THERE A CONFIDENTIAL VERSION OF THIS CHART?**

2 A. Westinghouse/Shaw is in negotiations with other parties concerning these
3 matters, and treats the costs of the individual items included in Change Order No.
4 16 as confidential. For that reason, the individual items are redacted in the public
5 version of this testimony but are available for review by parties that sign
6 confidentiality agreements related to them.

7 **Q. WHAT IS THE SOURCE OF THE REBATE LISTED ON THIS CHART?**

8 A. Under the EPC Contract, Westinghouse/Shaw initially planned to allocate
9 certain design finalization costs and other costs over the first four contracts for
10 AP1000 reactors. In our negotiations, we convinced Westinghouse/Shaw to agree
11 to give us a rebate of a share of those costs as contracts for reactors beyond those
12 four initial contracts were placed. The credit listed on Chart A reflects an
13 acceleration of the potential rebates from Shaw, which have not yet been earned,
14 as an off-set to the costs otherwise claimed.

15 **Q. WHAT IS THE LARGEST SINGLE COST ITEM CONTAINED IN**
16 **CHANGE ORDER NO. 16?**

17 A. The largest single item of cost contained in Change Order No. 16 is the
18 additional cost of constructing the shield building as redesigned to increase its
19 resistance to aircraft impacts.

20

21

1 **Q. WHEN WAS THAT REDESIGN APPROVED?**

2 A. That redesign was approved in December 30, 2011, by the NRC in DCD
3 Revision No. 19.

4 **Q. PLEASE EXPLAIN THE CIRCUMSTANCES SURROUNDING THE DCD**
5 **AMENDMENT.**

6 A. At the time the EPC Contract was negotiated, it was anticipated that the
7 NRC would require additional measures to be incorporated into the AP1000
8 design to strengthen its resistance to aircraft impacts. Shortly before the EPC
9 Contract was signed, the NRC issued the new rule concerning aircraft impacts in
10 draft form. But the final rule itself was not issued until after the EPC Contract was
11 signed. Meeting the requirements of the new rule proved more difficult and
12 expensive than anticipated resulting in an increase in the cost of the shield
13 building that was greater than had been budgeted.

14 **Q. PLEASE EXPLAIN THE ENGINEERING APPROACH CHOSEN BY**
15 **WESTINGHOUSE FOR STRENGTHENING THE AP1000'S RESISTANCE**
16 **TO AIRCRAFT IMPACTS.**

17 A. The original shield building design called for concrete walls and a concrete
18 roof poured over an internal frame of steel rebar. Temporary forms would hold
19 the concrete in place while it cured. From an engineering standpoint, the most
20 obvious way to improve resistance of such a building to aircraft impacts would be
21 to increase the thickness of the walls and roof. But engineering work showed that

1 it was not possible to increase the thickness of the walls and roof without reducing
2 the interior volume of the building to an unacceptable degree. In response,
3 Westinghouse proposed to use a continuous shell of steel on the inside and outside
4 of the shield building. In this design, the steel walls provide reinforcement for the
5 concrete which is poured between them. The walls are anchored to the concrete
6 by means of metal studs, called "Nelson studs," which are welded to the walls and
7 protrude into the space where the concrete is poured.

8 In addition, the new design required revisions to the structural connection
9 between the base-mat and the shield building walls and between the shield
10 building and the auxiliary building. Changes were also required to the air inlets
11 and the tension ring which are located at the transition between the shield building
12 wall and the roof.

13 **Q. HAD THIS DESIGN BEEN USED SUCCESSFULLY BEFORE?**

14 A. Yes. The design has been used successfully in multiple applications
15 outside of the United States. But because this design had not been used for this
16 type of application in this country, design codes documenting the strength and
17 performance of this type of construction had not been issued in the United States.
18 For that reason, the NRC required Westinghouse/Shaw to test and verify the
19 design performance of this construction approach as if it was being proposed for
20 the first time. As discussed below, the testing and review of the design played a

1 large role in the Westinghouse's inability to obtain approval of DCD Revision No.
2 19 within the anticipated schedule.

3 **Q. WHAT WAS THE BASIS FOR WESTINGHOUSE/SHAW'S CLAIM FOR**
4 **ADDITIONAL COSTS RELATED TO THE SHIELD BUILDING**
5 **REDESIGN?**

6 A. Westinghouse/Shaw asserted that it was entitled to recover the additional
7 costs of the new shield building design based on the provisions of the EPC
8 Contract that provide for change orders where cost increases are due to
9 "uncontrollable circumstances." Under the EPC Contract, "uncontrollable
10 circumstances" can mean, among other things, an order or other action by a
11 governmental authority that is not the result of the negligent or willful acts of the
12 party claiming uncontrollable circumstances. Westinghouse/Shaw claimed that the
13 aircraft impact rule and its interpretation by the NRC was a governmental order or
14 action falling within this definition of uncontrollable circumstances.

15 **Q. WAS SCE&G PREPARED TO CONTEST THAT CLAIM?**

16 A. During the negotiations, SCE&G indicated that it was ready to contest all
17 or part of Westinghouse/Shaw's claim related to the shield building costs. But we
18 also understood that Westinghouse/Shaw believed that they did have a claim.
19

1 **Q. HOW DID YOU DETERMINE THAT THE AMOUNT OF ADDITIONAL**
2 **COSTS BEING ASSERTED BY WESTINGHOUSE/SHAW FOR THE**
3 **SHIELD BUILDING DESIGN CHANGE WAS REASONABLE?**

4 A. As to all matters involved in Change Order No. 16, SCE&G insisted that
5 we would not begin negotiations until Westinghouse/Shaw provided us with a
6 detailed documentation of the costs underlying their claims. Members of the NND
7 teams reviewed in detail this "build" of costs and assessed those costs based on
8 their extensive construction and engineering experience. In some cases, we
9 convinced Westinghouse/Shaw to revise their cost estimates downward, as they
10 did when they reduced their overall claim from \$213.6 million to \$188.0. In
11 addition, we believe that our challenges to the amount of the asserted costs
12 ultimately played a role in convincing Westinghouse/Shaw to accept a change
13 order of \$137.5 million, rather than the \$188.0 million they claimed. In the end,
14 the cost data we received fully justified resolving this claim and the others
15 reflected in Change Order No. 16 at the levels reflected in the settlement
16 agreement and on Chart A.

17 **Q. PLEASE EXPLAIN THE ASPECT OF THE CHANGE ORDER RELATED**
18 **TO COL DELAY.**

19 A. When the EPC Contract was negotiated, we expected the COL for the Units
20 to be issued in mid-2011. In fact, the COL for the Units was not issued until
21 approximately nine months later, on March 30, 2012. Given that delay, and the

1 importance of the COL to the project schedule, it was necessary to re-baseline the
2 entire schedule to reflect the new COL issuance date.

3 **Q. WHY IS THE DELAY OF THE ISSUANCE OF THE COL IMPORTANT?**

4 A. The issuance date of the COL has always been a major milestone date for
5 the project. Much of the construction work on the Units cannot begin until
6 Westinghouse/Shaw has placed the nuclear safety-related concrete for the Units'
7 foundations. This concrete can only be placed once the COL is issued.

8 **Q. WHAT WAS THE REASON FOR THE COL DELAY?**

9 A. There were a number of reasons for the delay, and a number of ways of
10 looking at who and what caused it. But by any analysis, a principal reason for the
11 delay in issuing the COL was the delay in Westinghouse/Shaw obtaining approval
12 of DCD Revision No. 19.

13 **Q. WHY WAS APPROVAL OF DCD REVISION NO. 19 DELAYED?**

14 A. As mentioned above, the new shield building design involved a
15 construction technique that was new to United States regulators and so extensive
16 testing was required to verify its strength and performance. Difficulties with
17 satisfying the NRC staff concerning the testing program required to verify the
18 strength and performance of that design created lengthy delays in the permitting
19 process. In the end, the process took approximately four years.

20

1 **Q. PLEASE EXPLAIN HOW THIS TESTING AND VERIFICATION WAS**
2 **DONE.**

3 A. The testing of the shield building design was done chiefly in the
4 engineering laboratories of Purdue University. When tests were completed,
5 Westinghouse prepared engineering reports which were submitted along with the
6 test results to the NRC. Early in the process, a pattern emerged where NRC
7 review resulted in requests for additional testing, followed by further NRC review,
8 followed by requests for additional testing and in some cases requests for further
9 design amendments. The process became very time consuming and slowed down
10 the DCD Revision No. 19 approval by many months.

11 **Q. WHY WAS RESOLVING THESE ENGINEERING ISSUES SO TIME**
12 **CONSUMING?**

13 A. The required testing protocols involved destructive testing of sample panels
14 of the shield building wall, which meant that each cycle of testing required
15 building a new batch of sample panels to test a particular feature of the design or
16 to test its performance under a different set of loading conditions. To properly test
17 each new set of panels, the Purdue lab had to wait for nearly a month after
18 fabrication while the concrete in the panels cured to final strength. In the early
19 stages of the process, Westinghouse saw the additional tests as unnecessary and
20 unjustified given the acceptance and use of the design in other countries, and the
21 safety margins built into the design. When the Westinghouse engineering team

1 challenged the NRC staff's repeated requests for additional testing, relationships
2 grew strained. Disputes about testing became a source of delay in themselves.

3 **Q. WHAT DID SCE&G DO?**

4 A. SCE&G played a very active role in convincing Westinghouse to work with
5 NRC staff even where Westinghouse disagreed with the reasonableness of the
6 NRC positions.

7 **Q. WHAT WAS THE OUTCOME?**

8 A. In the end, a great deal of additional testing was done which thoroughly
9 validated the strength and resiliency of this design. Ultimately, the NRC staff was
10 assured of the strength of the design, but the length of time that this process took
11 was a major factor in the delay in the issuance of the COL. One NRC staffer
12 disagreed with the staff's assessment, but an independent NRC panel reviewed and
13 dismissed his assertions and supported the strength of the design.

14 **Q. WERE THERE OTHER REGULATORY ISSUES THAT MIGHT HAVE**
15 **DELAYED THE COL ISSUANCE HAD THE SHIELD BUILDING DESIGN**
16 **ISSUES BEEN RESOLVED EARLIER?**

17 A. Yes. Approving a strengthened shield building design was not the only
18 regulatory issue that potentially delayed the COL issuance.

19 **Q. PLEASE EXPLAIN.**

20 A. Under the National Environmental Policy Act ("NEPA"), the COL could
21 not be issued until a Final Environmental Impact Statement ("FEIS") was

1 approved for the project. COL issuance also required a Clean Water Act Section
2 401 certification establishing that the project could operate in compliance with
3 Clean Water Act standards.

4 **Q. WHAT HAPPENED TO DELAY THE FEIS AND SECTION 401**
5 **CERTIFICATON?**

6 A. All of these regulatory processes were delayed by positions taken by the
7 United States Environmental Protection Agency ("EPA") which were not
8 anticipated at the time the COL application was filed. In the end, the Section 401
9 Water Quality Certification was not issued until December 16, 2011, about the
10 same time that DCD Revision No. 19 was approved by the NRC.

11 **Q. PLEASE EXPLAIN WHY.**

12 A. When the COL application was filed in 2008, the environmental studies and
13 reports on which the environmental impact review would be based had been
14 completed and were provided to the NRC with the application. In as much as the
15 Units were being located at an existing nuclear generation site with more than 20
16 years of detailed environmental monitoring and data in hand, all parties expected
17 that the FEIS and the Section 401 certification could be obtained on a schedule
18 that easily supported COL issuance in mid-2011.

19 Based on past practice, and on the recommendation of knowledgeable and
20 experienced environmental consultants at Bechtel Corporation, the Environmental
21 Report identified the county-by-county corridors through which the transmission

1 lines supporting the Units would run, and quantified the environmental impacts of
2 placing the lines in those corridors. The specific location of the lines was left until
3 detailed engineering and siting studies were completed later in the process. This is
4 referred to in the industry as a "macro-corridor" approach.

5 **Q. WHY DID SCE&G WAIT TO SET THE SPECIFIC LOCATIONS OF**
6 **THESE LINES?**

7 A. As the Commission is aware, where green-field transmission lines are being
8 sited, the specific decision about where to locate a line within a particular
9 transmission corridor involves extensive public data gathering and opportunity for
10 public and landowner comment on alternative routes. This process ensures that in
11 determining the final location of the line the aesthetic, cultural and environmental
12 considerations most important to the people of the area are given appropriate
13 consideration. This community-based siting process is time-consuming and
14 typically is not begun, as was the case here, until the final decision to build a plant
15 and construct new lines to serve it is made. For that reason, it is industry practice
16 to base initial permitting of the plant and its lines on a macro-corridor assessment
17 of the environmental impacts of the lines, rather than on their precise locations.

18 **Q. HAD THE NATURAL RESOURCE AGENCIES ACCEPTED THIS**
19 **APPROACH IN OTHER CASES?**

20 A. Yes. The macro-corridor based approach for assessing impacts is an
21 approach that the natural resource agencies had accepted in past proceedings.

1 SCE&G's use of this approach went unchallenged during the initial scoping
2 process for our project. This was a period of approximately one year during which
3 the sufficiency of the environmental studies and the approach to the environmental
4 review of the project were subject to comment by interested parties. This
5 approach was also used in the NEPA review related to the Vogtle Units which
6 were being permitted by Southern Company simultaneously with SCE&G's Units.
7 In fact, the Vogtle Units received a favorable FEIS based on an assessment of
8 environmental impacts of transmission done on the same macro-corridor basis
9 used by SCE&G.

10 **Q. WHAT HAPPENED IN SCE&G'S CASE?**

11 A. For reasons SCE&G does not fully understand, in comments filed late in
12 the review process for our Units, the EPA took the position that specific
13 transmission line routes had to be identified, and the environmental impacts of
14 those specific routes had to be assessed before the environmental review could
15 proceed. The Army Corps of Engineers (the "Corps"), which was the lead Federal
16 agency for NEPA issues, had originally accepted SCE&G's macro-corridor
17 approach. But in response to the EPA, the Corps reversed its position. This meant
18 that more than a year into the permitting process, well after scoping had been
19 completed, the review of the application was suspended and SCE&G was required
20 to locate precise routes for the new transmission lines, and was also required to

1 assess the environmental impacts of the new routes before the environmental
2 process could proceed.

3 **Q. WHAT DID SCE&G DO IN RESPONSE?**

4 A. In response, SCE&G decided to route its new transmission lines in existing
5 corridors with the exception of one six-mile segment of 230 kiloVolt line in the
6 Blythewood-Killian area. This approach allowed the routes to be established
7 quickly, and environmental impacts from them to be assessed on an expedited
8 basis. However, even this expedited approach delayed the permitting process
9 substantially. As a result, the FEIS was not issued until April of 2011, more than
10 three years after the initial filing. The issuance of the Section 401 certification
11 was delayed until December of 2011, approximately two weeks before the NRC
12 approval of DCD Revision No. 19.

13 **Q. WHAT RELEVANCE DID THIS HAVE TO THE QUESTIONS OF WHO**
14 **WAS RESPONSIBLE FOR THE COL DELAY?**

15 A. Under the EPC Contract, obtaining the NEPA and Clean Water Act
16 authorizations required for the COL was clearly SCE&G's responsibility. If there
17 had not been a settlement of the claim for cost recovery due to the COL delay,
18 then we expect that Westinghouse/Shaw would have argued that the delay in the
19 Section 401 certification was as much the cause of the COL delay as the delay in
20 approval of DCD Revision No. 19. The timing of the permitting process supports
21 that argument. In response, SCE&G would have argued that the resource agencies

1 considering the Section 401 certification knew there was no urgency to their work
2 as long as the DCD revision process was delayed. SCE&G would have argued
3 that if the DCD Revision No. 19 process had not been delayed, it could have
4 accelerated the Section 401 certification process. In addition, there were other
5 delays in the filing for the Section 401 certification that were due to
6 Westinghouse/Shaw's delays in providing final design documents as to water-
7 quality related structures. The point is that these would have been complex and
8 difficult issues to litigate. The expense and risks of litigation would have been
9 significant.

10 **Q. WHAT DID YOU DO TO DETERMINE THAT THE AMOUNT OF**
11 **ADDITIONAL COSTS BEING ASSERTED BY WESTINGHOUSE/SHAW**
12 **AS A RESULT OF COL DELAY WAS REASONABLE?**

13 A. Members of the NND teams reviewed in detail the build of costs underlying
14 the Westinghouse/Shaw claims and made assessments based upon their extensive
15 construction and engineering experience. Just as with the shield building redesign
16 costs, Westinghouse/Shaw agreed to revise their claims in some cases. But in the
17 end, the cost data we received fully justified resolving these claims at the level
18 reflected in the settlement agreement.

19 **Q. IN THE END, HOW WERE THESE MATTERS RESOLVED?**

20 A. There were multiple parts to the resolution of these matters. On the one
21 hand, we challenged Westinghouse/Shaw's cost data and their contractual

1 entitlement to the claim. On the other hand, we directed Westinghouse/Shaw to
2 take advantage of the opportunity created by a delay in Unit 2 to close the gap in
3 the construction schedules for the two Units. Closing that gap allows
4 Westinghouse/Shaw to optimize construction schedules so that crews and
5 equipment completing work on one area of Unit 2 can often move seamlessly to
6 begin work on the similar area of the Unit 3. This avoids the need for contractors
7 to send crews off to work somewhere else for a year or more and remobilize later
8 on the site. In negotiations, Westinghouse/Shaw reduced their claim for COL
9 delay costs by approximately \$15.9 million based on the synergies involved in
10 rescheduling both Units.

11 **Q. DO YOU BELIEVE THAT THE SETTLEMENT REACHED ON THE COL**
12 **DELAY CLAIM WAS A REASONABLE AND PRUDENT RESOLUTION**
13 **TO IT?**

14 **A.** Yes. Based on my knowledge of the facts, the parties and my experience in
15 this industry, I believe that the resolution of the COL delay claim was fair,
16 reasonable and prudent. The resolution represents a compromise by
17 Westinghouse/Shaw of its claims and a reduction in the amount of those claims as
18 a result of the rescheduling of the gap between the two Units. Furthermore, the
19 settlement reflects a far better outcome for SCE&G as owner of the project than
20 protracted, divisive and expensive litigation.

1 **Q. PLEASE DESCRIBE THE COMPONENT OF CHANGE ORDER NO. 16**
2 **THAT RELATES TO THE DECISION TO USE A HIGHER STRENGTH**
3 **STEEL IN THE STRUCTURAL MODULES AND OTHER DESIGN**
4 **CHANGES.**

5 A. In proving the design of the AP1000 reactor to the NRC,
6 Westinghouse/Shaw determined that the design would benefit materially from the
7 use of higher strength steel in the structural modules that are being fabricated by
8 Shaw Modular Solutions ("SMS"). They also determined that it would be
9 beneficial to make the changes to the design to improve constructability. The
10 NRC staff concurred and the design changes were approved in DCD Revision No.
11 19. The resulting design changes increase the construction costs for the Units by
12 an amount which SCE&G verified through audits.

13 **Q. DID SCE&G CONTEST THE CLAIM THAT THESE WERE CHANGES**
14 **TO THE DESIGN REQUIRED BY REGULATION?**

15 A. SCE&G did contest Westinghouse/Shaw's contractual entitlement to this
16 aspect of the change order and negotiated a settlement of the claim as set forth on
17 Chart A.

18

19

1 Q. WHAT DID YOU DO TO DETERMINE THAT THE AMOUNT OF
2 ADDITIONAL COSTS BEING ASSERTED BY WESTINGHOUSE/SHAW
3 FOR STRUCTURAL MODULE REDESIGN WAS REASONABLE?

4 A. Members of the NND teams reviewed in detail the build of costs underlying
5 the Westinghouse/Shaw claims and made an assessment based upon their
6 extensive construction and engineering experience. This was an area where we
7 took the hardest line because we believed that these claims by Westinghouse/Shaw
8 were the weakest from a legal standpoint. We believe that the cost estimate
9 agreed to in the settlement agreement is reasonable in light of the facts
10 surrounding these claims.

11 Q. PLEASE DESCRIBE THE COMPONENT OF CHANGE ORDER NO. 16
12 THAT RELATES TO THE UNANTICIPATED ROCK CONDITIONS AT
13 THE UNIT 2 SITE.

14 A. The pricing in the EPC Contract was based on an understanding of rock
15 conditions at the Units that was based on test drillings. Such test drillings, even
16 when conducted within accepted industry standards, often do not disclose
17 conditions that affect the cost of the work. It is not unusual, when full excavation
18 occurs, to determine that rock conditions are not uniform and that the variations
19 will increase costs. In this case, excavation showed that in some parts of the Unit
20 2 foundation area the rock levels are lower than anticipated, requiring the
21 placement of additional concrete.

1 **Q. DID SCE&G CONTEST THE CLAIM THAT THIS WAS A CHANGE DUE**
2 **TO UNANTICIPATED CONDITIONS ON THE SITE?**

3 A. No. SCE&G did not contest Westinghouse/Shaw's claim that these costs
4 are recoverable under the EPC Contract as costs due to unanticipated conditions
5 on the site.

6 **Q. WHAT DID YOU DO TO DETERMINE THAT THE AMOUNT OF**
7 **ADDITIONAL COSTS BEING ASSERTED BY WESTINGHOUSE/SHAW**
8 **FOR UNANTICIPATED ROCK CONDITIONS WAS REASONABLE?**

9 A. Members of the NND teams reviewed in detail the build of costs underlying
10 the Westinghouse/Shaw claims and made assessments based on their extensive
11 construction and engineering experience. In response, Westinghouse/Shaw
12 adjusted their claim by several hundred thousand dollars. Based on our review
13 and analysis, we believe that the cost estimates agreed to in the settlement
14 agreement for unanticipated rock conditions are fully justified and reasonable.

15 **Q. ARE THERE OTHER ASPECTS OF THE SETTLEMENT AGREEMENT**
16 **THAT BENEFIT THE PROJECT?**

17 A. As part of the settlement agreement, Westinghouse/Shaw also agreed to fix
18 the escalation rate on approximately \$1.0 billion of work to be done under the
19 EPC Contract. That work would have been escalated under Handy Whitman
20 escalation rates otherwise. Now, this work will be subject to escalation at the
21 same fixed rate that applies to the Firm with Adjustment A category of costs under

1 the EPC Contract. With this change, all fixed and firm EPC Contract cost
2 categories are now subject to fixed escalation rates.

3 **Q. HOW DID THIS AGREEMENT CHANGE COST FORECASTS?**

4 A. Although the primary purpose of the change in escalation was to limit
5 future escalation, the cost of the project in future dollars dropped by
6 approximately \$4 million as a result of applying the new escalation rate.

7 **Q. DID OTHER CHANGES RESULT FROM THESE DISCUSSIONS?**

8 A. While not formally included in the settlement agreement, in response to
9 concerns we raised concerning structural module fabrication issues,
10 Westinghouse/Shaw agreed to shift fabrication of an important group of shield
11 building wall modules for the Units to a contractor at Newport News shipyard.
12 This contractor has the experience and facilities to do this work very effectively.
13 Shifting responsibility for these modules to Newport News will reduce the
14 pressure on the SMS facility in Lake Charles. This change is a major benefit for
15 the project.

16 **THE THREE PRIOR CHANGE ORDERS**

17 **Q. PLEASE DESCRIBE OTHER CHANGE ORDERS THAT SCE&G IS**
18 **PRESENTING HERE.**

19 A. In this docket, SCE&G is also including in cost forecasts the effects of
20 Change Orders Nos. 12, 14 and 15 and related activities. These change orders

1 predate the settlement agreement that will be reflected in Change Order No. 16.

2 Of these, Change Order No. 14 is the most significant.

3 **Q. WHAT DOES CHANGE ORDER NO. 14 INVOLVE?**

4 A. As the Commission is aware, in recent years the protection of key
5 infrastructure against cyber-attack ("Cyber Security") has become an increasing
6 priority of electric utilities, their regulators, the Department of Homeland Security,
7 and others. The NRC now requires robust Cyber Security measures to be
8 incorporated in all new and existing nuclear facilities. In late 2011, SCE&G
9 reached an agreement with Westinghouse/Shaw on a phased approach for
10 ascertaining the costs that will be associated with strengthening the Units'
11 defenses against cyber-attacks. The Phase I scope of the Cyber Security plan will
12 involve review of the specific equipment and software that will be used in the
13 Units to identify potential vulnerabilities to cyber-attack and to devise a scope of
14 work to protect against those vulnerabilities. Those costs are reflected directly in
15 Change Order No. 14. Phase II will involve the actual software programming and
16 other work necessary to overcome the vulnerabilities identified in Phase I. The
17 forecasted cost of Phase II is included in the adjustment to cost schedules
18 presented here. The combined costs of both phases are currently estimated to be
19 \$5.9 million but the final costs will depend on the results of Phase I. Other phases
20 of work may be required but are not known at this time.

1 Q. ARE THE COSTS REFLECTED IN THIS CHANGE ORDER
2 REASONABLE AND PRUDENT?

3 A. The cost of providing cyber-security is a reasonable and prudent cost of the
4 project that is the result of changing regulatory requirements. New nuclear
5 generation is not unique in this regard. Cyber Security cost is a cost that is being
6 experienced at other generation stations and transmission facilities across our
7 system. We have verified the amounts involved based on our negotiation of this
8 scope of work with Westinghouse/Shaw. We believe that the cost forecasted here
9 is accurate based on current information.

10 Q. WHAT DOES CHANGE ORDER NO. 12 INVOLVE?

11 A. During the last quarter of 2011, Westinghouse/Shaw initiated Change Order
12 No. 12 requesting reimbursement for Shaw's increased costs as a result of a change
13 in law related to portions of the Health Care and Education Reconciliation Act of
14 2010 ("Health Care Act") and prior health care acts. SCE&G approved the change
15 order in December 2011. The total costs associated with this action are \$135,573
16 and are spread throughout the remaining period of the project. At this time,
17 Westinghouse has not quantified any additional costs related to the Health Care
18 Act. Additional change orders may be generated by Westinghouse/Shaw to cover
19 future cost impacts associated with the Health Care Act.

20

1 **Q. ARE THE COSTS REFLECTED IN THIS CHANGE ORDER**
2 **REASONABLE AND PRUDENT?**

3 A. The additional health care costs are reasonable, necessary and prudent costs
4 of the project that are the result of new legal requirements imposed on
5 Westinghouse/Shaw. We have verified the amounts involved and believe that they
6 are accurate.

7 **Q. WHAT DOES CHANGE ORDER NO. 15 INVOLVE?**

8 A. On December 9, 2011, Westinghouse/Shaw presented SCE&G with an
9 estimate for a detailed scope of work and associated costs for a revision to the
10 design of the waste water discharge piping for gravity drainage, as specified in
11 SCE&G's COL application. SCE&G prefers the gravity design because it
12 involves fewer pumps, motors and other moving parts that require maintenance.
13 SCE&G understood when the COL application was submitted that there could be a
14 charge associated with this change. Now that design work is complete,
15 Westinghouse/Shaw has determined that the cost of this work will be \$8,250.
16 SCE&G has verified this amount and finds it to be a reasonable and prudent cost
17 that supports a beneficial change to the project design.

18 **Q. DO YOU ANTICIPATE FUTURE FILINGS TO INCREASE THE COSTS**
19 **OF THE PROJECT?**

20 A. In this proceeding, we are putting before the Commission and the public all
21 of the cost and schedule changes that we have identified to date. We have six

1 years left on this project. Further changes are likely. But we cannot put before the
2 Commission and the public changes that we have not yet identified. Our
3 commitment is to manage the costs of the project carefully, and to put before the
4 Commission the changes in costs as they are identified.

5 **UPDATED CONSTRUCTION MILESTONE SCHEDULE**

6 **Q. PLEASE DESCRIBE EXHIBIT NO. 1 (SAB-3).**

7 A. Exhibit No. 1(SAB-3) is an updated version of the construction milestone
8 schedule for the Units. It has been updated to reflect the substantial completion
9 dates for Units 2 and 3 of March 15, 2017, and May 15, 2018, respectively.

10 **Q. WHO PREPARED THIS UPDATED MILESTONE SCHEDULE?**

11 A. SCE&G prepared the updated schedule based on construction milestones
12 and equipment fabrication and procurement milestones provided by
13 Westinghouse/Shaw as a result of the decision to reschedule Units.

14 **Q. IS THIS A REASONABLE AND PRUDENT SCHEDULE FOR THE**
15 **UNITS?**

16 A. Yes. The new milestone schedule contains milestone dates that support the
17 new substantial completion dates for the Units and are reasonable and prudent in
18 all respects. Mr. Marsh and I testify concerning the reasons for the changes in the
19 substantial completion dates for the Units. Those reasons relate to matters that are
20 not unexpected in a construction project of this size and complexity and are in no
21 way the sign of any lack of responsible and prudent management of the project. In

1 addition, under the new schedule, Unit 2 will be placed in service well within the
2 original 18-month schedule contingency, and the substantial completion date for
3 Unit 3 will be advanced by seven and one-half months. As Mr. Marsh testifies,
4 our plans show that the completion of the Units will permit the timely retirement
5 of 730 MW of coal-fired capacity in existing units that are too small to be brought
6 up to increasingly stringent emissions standards in a cost-effective way.
7 Advancing Unit 3's substantial completion date will allow for the acceleration this
8 retirement plan.

9 For all of these reasons, this updated construction milestone schedule
10 represents a reasonable and prudent schedule for the completion for the project. It
11 reflects necessary changes to the construction schedule and is not the result of any
12 failure of the Company to diligently and prudently manage the project.

CONCLUSION

13
14 **Q. ARE THE UPDATES REQUESTED IN THIS PROCEEDING**
15 **REASONABLE AND PRUDENT?**

16 **A.** Yes they are. As President for Generation and Transmission, I am involved
17 on an on-going basis with all major aspects of the construction project. The
18 adjustments requested in this proceeding, adjustments as to EPC costs, Owners
19 cost and Transmission cost, are adjustments that I know to represent reasonable
20 and prudent changes in the cost and construction schedules for the Units. In my
21 professional opinion, the adjustments are the result of the normal and expected

1 evolution of project cost forecasts and construction scheduling for a project of this
2 size and scope. I ask the Commission to approve these adjustments as presented.

3 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

4 **A.** Yes, it does.

5

1 BY MR. ZEIGLER:

2 Q Have you also prepared a summary of your rebuttal
3 testimony?

4 A I have.

5 Q Would you please give that to the Commission?

6 A Certainly. My rebuttal testimony points out certain
7 inaccuracies and misunderstandings in the testimony of
8 the Sierra Club witness, Dr. Mark Cooper.

9 Dr. Cooper asserts that SCE&G is currently
10 experiencing what he calls massive cost overruns because
11 it charged ahead with a lowball estimate for
12 construction of the units. Neither of these statements
13 is supported by the record.

14 Currently, the gross construction of the units in
15 future dollars is approximately \$550 million below the
16 initial forecast. That's the forecast that was approved
17 in the original BLRA proceeding. In 2007 dollars, the
18 project is \$18 million above our initial forecast.
19 That's an increase of approximately 4/10 percent. These
20 estimates were subject to detailed audits by the Office
21 of Regulatory Staff and its outside consultants.

22 SCE&G has negotiated fixed or firm pricing with
23 Westinghouse/Shaw on approximately two-thirds of the EPC
24 costs of the units. The initial site work, major
25 permitting and licensing, standard plant design,

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1 switchyard construction, transmission siting, and a
2 number of other items have been completed or are well
3 underway. Costs related to COL delay have been
4 quantified through a settlement with Westinghouse/Shaw.
5 Shield building redesign and module redesign have been
6 completed and their costs agreed to. The unanticipated
7 rock conditions have been addressed and their costs
8 quantified.

9 Risks continue to be identified and addressed, but
10 the cost today with escalation are \$1/2 billion less
11 than the original estimate in future dollars and only
12 four-tenths above the original estimate in 2007 dollars.
13 These figures do not reflect massive cost overruns.

14 Dr. Cooper suggests that SCE&G is not doing a
15 reasonable job regarding DSM and alternative energy
16 programs. Specifically, he states that SCE&G is well
17 below the national average in efforts and results, and
18 appear to be falling behind.

19 In 2008, SCE&G retained David Pickles in connection
20 with our DSM programs. Mr. Pickles is a nationally
21 recognized expert in these programs. Mr. Pickles
22 testified in 2010 that SCE&G's DSM efforts, as measured
23 by a percentage of electric revenues, compares favorably
24 with peer group utilities. We placed 18th out of 41.
25 Our initial DSM program has met its expectations, and we

1 have programs that are geared to reasonably achievable
2 levels of savings.

3 Dr. Cooper suggests that the power to be provided
4 by the units could be replaced by DSM resources at
5 approximately \$1,000 a kilowatt. However, in the
6 settlement entered into in the 2010 DSM docket, SCE&G
7 agreed to provide a study for review by ORS and a DSM
8 advisory group. The purpose of the study was to
9 determine the reasonably achievable level of DSM savings
10 on SCE&G's system. A reasonably achievable level of DSM
11 savings shown in that study are already included in our
12 demand forecast. They're not sufficient to supplant the
13 need for the units.

14 DSM customers most interested in taking advantage
15 of SCE&G's DSM programs are the easiest and least
16 expensive to reach, so from a cost-per-kW-saved
17 perspective, the current DSM results per dollar spent
18 are not likely to be indicative of future outcomes.

19 Alternative generation sources are not cost-
20 competitive on our system at present. South Carolina
21 cannot support geothermal, hydro, onshore wind, or solar
22 resources on a scale sufficient to supplant the units.
23 The infrastructure to capture offshore wind resources,
24 while potentially available, is unproven both as to cost
25 and engineering. This is particularly true in a

1 hurricane-prone area like South Carolina.

2 The largest thin-film photovoltaic solar
3 installation in the Southeast is on our system. It
4 achieves a capacity factor of 15 percent. We have
5 determined that to replace the energy from the units
6 with solar of this type would require more than 30,000
7 acres of arrays, and would cost approximately \$34
8 billion. This does not include the cost of gas capacity
9 to provide a reliable backstand for periods when solar
10 does not operate.

11 Dr. Cooper makes a number of other statements
12 which, for the record, I have responded to in my
13 rebuttal testimony. In substance, Dr. Cooper requests
14 that SCE&G be ordered to abandon construction of the
15 units. If that happened, SCE&G would incur costs of
16 winding down contracts related to construction and
17 decommissioning the site. Our initial estimates show
18 these costs would be material. However, the longer-term
19 issue would be that abandoning the project would deny
20 SCE&G and its customers the benefit of 1,229 megawatts
21 of reliable, non-emitting nuclear generation that is not
22 subject to risks associated with fossil-fuel generation.

23 I concur with Mr. Marsh that SCE&G's decision to
24 build nuclear generation was not based on a single
25 factor, such as fuel costs or carbon regulation; the

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1 decision was made because our studies showed that adding
2 a significant amount of nuclear generation reduces our
3 customers' exposure to the fossil-fuel risks while
4 providing reliable base-load generation. Without new
5 nuclear, our reliance on fossil fuel will exceed 70
6 percent in 2019. That would put our system and
7 customers at risk for volatility in fuel prices and the
8 unpredictable costs of future CO₂ and other air-quality
9 regulations.

10 In conclusion, the history of the project and the
11 current cost projections reflect neither a lowball
12 estimate of costs nor massive cost overruns. As a
13 replacement for base-load generation, alternative
14 generation remains out of reach logistically,
15 practically, and financially. The evidence does not
16 support the decision not to proceed with these units.

17
18
19
20
21
22
23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED REBUTTAL TESTIMONY OF STEPHEN A.
25 BYRNE FOLLOWS AT PGS 266-280]

1 **REBUTTAL TESTIMONY**
2 **OF**
3 **STEPHEN A. BYRNE**
4 **ON BEHALF OF**
5 **SOUTH CAROLINA ELECTRIC & GAS COMPANY**
6 **DOCKET NO. 2012-203-E**

7 **Q. PLEASE STATE YOUR NAME AND OCCUPATION.**

8 A. My name is Stephen A. Byrne, and I am President for Generation
9 and Transmission of South Carolina Electric & Gas Company ("SCE&G"
10 or the "Company").

11 **Q. ARE YOU THE SAME STEPHEN A. BYRNE WHO IS PROVIDING**
12 **DIRECT TESTIMONY IN THIS PROCEEDING?**

13 A. I am.

14 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN**
15 **THIS PROCEEDING?**

16 A. My testimony points out several factual inaccuracies and
17 misunderstandings in the positions asserted by the Sierra Club through the
18 testimony of its witness Dr. Cooper.

19 **Q. ON PAGE 24 OF HIS TESTIMONY, DR. COOPER ACCUSES**
20 **SCE&G OF HAVING "CHARGED AHEAD WITH A LOW BALL**
21 **ESTIMATE" OF THE COST OF THE UNITS, AND ON PAGE 21**

**ASSERTS THAT YOU HAVE EXPERIENCED A 'MASSIVE COST
OVERRUN.' HOW DO YOU RESPOND?**

A. The chart below shows each of the cost estimates that SCE&G has put before this Commission, beginning with the initial Base Load Review Act (BLRA) order, which was issued by the Commission in 2009, and including the orders issued in 2010 and 2011 amending the original BLRA order and the request made in this proceeding. The decline in capital costs forecasts in 2007 dollars between Order No. 2010-12 and 2011-345 reflects the removal of owner's contingency amounts and associated escalation from the forecasts as required by the opinion of the Supreme Court of South Carolina in *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, 388 S.C. 486, 697 S.E.2d 587 (2010).

Chart C: Summary of Nuclear Filings (millions of \$)

<u>Forecast Item</u>	<u>Order No. 2009-104(A)</u>	<u>Order No. 2010-12</u>	<u>Order No. 2011-345</u>	<u>Requested Here</u>	<u>Request vs. Order No. 2009-104(A)</u>
Capital Cost, 2007 Dollars	\$4,535	\$4,535	\$4,270	\$4,553	\$18
Escalation	\$1,514	\$2,025	\$1,261	\$971	(\$543)
Total Project Cash Flow	\$6,049	\$6,560	\$5,531	\$5,524	(\$525)
AFUDC	\$264	\$316	\$256	\$238	(\$26)
Gross Construction	\$6,313	\$6,875	\$5,787	\$5,762	(\$551)

1 This chart shows that the gross construction cost of the project in
2 future dollars is approximately \$551 million *below* the initial forecast
3 approved in the 2009 BLRA proceeding. Four years into the work, the cost
4 of the project in 2007 dollars has increased by \$18 million above our initial
5 forecast or slightly less than four-tenths of one percent.

6 **Q. HOW DO YOU RESPOND TO DR. COOPER'S ASSERTION ON P.**
7 **21 OF HIS TESTIMONY THAT "COST OVERRUNS FOR**
8 **NUCLEAR HAVE TAKEN BACK ALL OF THE REDUCTIONS IN**
9 **ESCALATION THAT COULD HAVE LOWERED CONSUMER**
10 **BILLS?"**

11 A. Dr. Cooper's testimony is inaccurate. As we have disclosed in our
12 quarterly reports and in the filings in this docket, the cost of the Units in
13 future dollars is more than half-a-billion dollars less than the estimates
14 approved by the Commission in the initial BLRA proceeding.

15 **Q. THESE FIGURES NOT WITHSTANDING, HOW DO YOU**
16 **RESPOND TO DR. COOPER'S ASSERTION THAT IN THE**
17 **ORIGINAL BLRA PROCEEDING SCE&G PRESENTED THE**
18 **COMMISSION WITH A "LOW-BALL ESTIMATE" OF THE**
19 **PROJECT?**

20 A. First of all, in the original BLRA proceeding, our cost forecasts and
21 the EPC Contract were audited in detail by consulting firms retained by the

1 Office of Regulatory Staff ("ORS") and by personnel within those
2 consulting firms that had extensive practical experience with major electric
3 generation projects including nuclear projects. They found nothing to
4 indicate that these estimates were inaccurate, and certainly not intentionally
5 inaccurate as Dr. Cooper's choice of words would suggest. In addition, as
6 my prior testimony and that of Mr. Marsh explain, SCE&G has now
7 negotiated fixed or firm pricing on more than two-thirds of the Units' cost
8 under the EPC Contract. Furthermore, the initial site work, major
9 equipment procurement, major permitting and licensing, standard plant
10 design, switchyard construction, transmission siting and a number of other
11 items are either completed or well-advanced. We have negotiated and
12 resolved the commercial issues related to the shield building redesign, COL
13 delay, structural module redesign and unanticipated rock conditions on site.
14 We have been subject to ongoing ORS audit and review throughout this
15 process. As envisioned by the BLRA, we have come before this
16 Commission on a regular basis to present updates and adjustments as
17 circumstances have required. In those proceedings, parties have had full
18 rights of discovery of costs, budgets and other information, as well as cross-
19 examination.

20 In spite of this maturing of the project and review in the regulatory
21 process, our costs today with escalation are half-a-billion dollars below the

1 original estimate and are only 0.397% above the original estimate in 2007
2 dollars. Obviously, unanticipated conditions could result in costs
3 increasing in the future. But there is nothing whatsoever to substantiate Dr.
4 Cooper's claim that SCE&G "charged ahead with a low ball estimate" in
5 presenting the cost of these Units to the Commission and to the public. The
6 experience of the last four years contradicts that assertion.

7 **Q. HOW DO THE PRICES OF SCE&G'S NEW NUCLEAR UNITS**
8 **COMPARE TO ENERGY INFORMATION ADMINISTRATION**
9 **ESTIMATES?**

10 A. The published Energy Information Administration ("EIA") estimates
11 for nuclear construction cost are based on 2010 dollars. We have de-
12 escalated the EIA estimates to 2007 dollars to match SCE&G estimates,
13 and they show that EIA estimates costs per KW for new nuclear
14 construction of between \$4,938 and \$4,275. SCE&G's current estimates of
15 costs for the Units in 2007 dollars after removing transmission costs are
16 \$3,438. Given the superior nature of the Jenkinsville site --which we
17 already owned, the ability to share resources with Unit 1, and the price
18 advantage we believe SCE&G locked in with Westinghouse/Shaw by being
19 a first mover in this area, the difference in price is well within our
20 expectations.

1 **Q. HOW DO YOU RESPOND TO THE SUGGESTION THAT SCE&G**
2 **IS NOT AGGRESSIVELY SEEKING TO CONTROL COSTS ON**
3 **THIS PROJECT?**

4 A. This is not the case. We have assembled a team of exceptionally
5 capable and experienced construction, accounting and auditing experts to
6 provide cost control for this project. We are watching costs extremely
7 closely, and have held change orders and change order costs to a minimum,
8 as my direct testimony details. We have pushed hard positions in our
9 negotiations with Westinghouse/Shaw and have been successful in reaching
10 agreements that protect our interests and those of our customers. There is
11 no substance to the suggestion that our cost control efforts are anything but
12 effective.

13 **Q. HOW DO YOU RESPOND TO DR. COOPER'S ASSERTION ON P.**
14 **19 OF HIS TESTIMONY THAT AS TO SCE&G'S ENERGY**
15 **EFFICIENCY PROGRAMS, STUDIES SHOW THAT SCE&G IS**
16 **"WELL BELOW THE NATIONAL AVERAGE IN EFFORTS AND**
17 **RESULTS AND APPEAR[S] TO BE FALLING BEHIND?"**

18 A. Dr. Cooper appears not to have sufficiently researched this issue.
19 The studies he cites all predate SCE&G's comprehensive review and ramp-
20 up of its Demand Side Management/energy efficiency ("DSM") as
21 discussed in Mr. Marsh's direct testimony. SCE&G's DSM consultant, Mr.

1 David Pickles, who practices nationally and is a principal consultant to the
2 EPA Energy Star program, testified as follows in Docket No. 2009-261-E:

3 *[W]e estimate that successful implementation of these programs [as*
4 *approved in Order No. 2010-472] over three years will result in*
5 *savings of over 62 MW and 333,363 MWh per year. This is*
6 *equivalent to reducing annual retail energy sales by approximately*
7 *0.6% per year (in Year 3). These results compare favorably with*
8 *peer utilities, putting SCE&G approximately 17 out of 41 peer*
9 *utilities with respect to DSM energy savings as a percent of system*
10 *retail sales. Similarly, SCE&G's planned spending on its program*
11 *in Year 3 at \$25 Million is approximately 1.8% of its retail annual*
12 *revenues. This also compares favorably with a group of peer*
13 *utilities, putting SCE&G 18 out of 41 utilities. It is my professional*
14 *judgment that these anticipated savings and expenditures represent*
15 *an aggressive commitment to DSM for SCE&G.*

16 Pickles Direct Testimony, Docket 2009-261-E, p. 4. This is the DSM plan
17 that SCE&G is pursuing. We offered the first of our new suite of DSM
18 programs to the public beginning in late 2010 and ramped them up in 2011.

19 **Q. HOW DO YOU RESPOND TO DR. COOPER'S INFERENCE ON P.**
20 **19 OF HIS TESTIMONY THAT THE GENERATION OF THE**
21 **NUCLEAR UNITS COULD BE REPLACED BY DSM RESOURCES**
22 **AT APPROXIMATELY \$1,000 PER MW?**

23 A. As shown in the Company's testimony in Docket 2009-261-E, the
24 Company's present DSM plans are based on a comprehensive evaluation of
25 DSM potential in SCE&G's service area, and reflect the reasonably
26 achievable capacity savings from DSM programs indicated by that
27 evaluation. In the settlement agreement entered into in Docket 2009-261-E,
28 SCE&G agreed to provide a follow-up DSM potential study for review by

1 ORS and the DSM advisory group established by Order No. 2010-476.
2 That study was prepared and shows that reasonably achievable DSM
3 savings are not sufficient to supplant the need for the Units. In fact,
4 reasonably achievable capacity savings from DSM are factored into
5 SCE&G's demand forecasts and the generation plans to meet those
6 demands.

7 **Q. WHAT PREVENTS YOU FROM ACHIEVING FUTURE**
8 **CAPACITY SAVINGS AT THE PRICES THAT DR. COOPER**
9 **SUGGESTS ARE POSSIBLE?**

10 **A.** The initial success of our DSM programs is meeting expectations,
11 but the cost per MW saved during this initial period is not indicative of a
12 cost per MW that we can expect to save over the long term when the most
13 productive energy savings opportunities have been exhausted. In the initial
14 ramp up of DSM programs, the most conservation-minded customers and
15 earliest adopters of new technologies tend to predominate. The projects
16 and measures adopted in the early stages of roll out tend to represent those
17 with the highest and fastest payback. These are the easiest and least
18 expensive customers to reach and projects to promote.

19 **Q. HOW DO YOU RESPOND TO DR. COOPER'S ASSERTION ON P.**
20 **22-23 OF HIS TESTIMONY THAT IN THE ORIGINAL BLRA**

1 **FILINGS SCE&G FAILED TO IDENTIFY THE OPERATIVE RISK**
2 **FACTORS SURROUNDING NUCLEAR CONSTRUCTION?**

3 A. This assertion is not accurate. Each of the risk factors that Dr.
4 Cooper identifies—staffing challenges, supply chain challenges, NRC
5 licensing challenges, and evolving requirements—were expressly identified
6 and discussed in the section of the BLRA application related to risk, which
7 is Exhibit J to the SCE&G's Combined Application in Docket No. 2009-
8 196-E. A copy of that document is attached to my testimony as Exhibit No.
9 ___ (SAB-4).

10 Q. **HOW DO YOU RESPOND TO DR. COOPER'S ASSERTION ON P.**
11 **19 OF HIS TESTIMONY THAT "ALTERNATIVES LIKE WIND,**
12 **SOLAR PHOTOVOLTAICS, GEOTHERMAL, AND HYDRO . . .**
13 **ARE PROJECTED TO BE COST COMPETITIVE WITH CENTRAL**
14 **STATION GENERATION?"**

15 A. There are no geothermal resources in SCE&G's territory or
16 immediately adjacent to it. As to hydro, there are no large-scale
17 undeveloped hydro resources that can practically be developed in our
18 territory. The environmental community would oppose such projects if
19 they were available. Wind resources in this area are limited to off-shore
20 wind. The environmental, aesthetic, cost and engineering challenges with
21 establishing large off-shore wind farms have not been resolved, certainly

1 not in a hurricane prone coastal area like South Carolina's. As to solar, we
2 now have data from the largest thin-panel photovoltaic ("PV") solar
3 installation in the Southeast which is located on our system and went into
4 service in 2011. It is a 2.6 MW (nameplate) facility that costs \$13 million
5 and covers 10 acres. With an availability factor of nearly 100%, that
6 installation is achieving a capacity factor of 15%, which is the capacity
7 factor that our engineering studies predicted.

8 This \$13 million cost does not include the cost of land or supporting
9 structures which the customer provided for this installation. Generation
10 from this resource is dependent on time of day and weather conditions, so it
11 would need to be supported with dispatchable generation like gas-fired
12 generation. The cost of that gas generation would need to be factored into
13 the price calculation to have a reasonable comparison. Based on these data,
14 replacing SCE&G's share of the energy generated by the Units with solar
15 generation at this cost and level of generation per acre would require a solar
16 installation of approximately 32,000 acres, or more than 24,000 standard
17 American football fields, at a cost per acre of \$1.3 million, without land and
18 supporting structures, or gas generation to stand behind it. Using this
19 project as a guide, the price of replacing the energy from the Units with a
20 similar quantity of thin-panel PV solar would be approximately \$40 billion

1 based on 2011 prices, again without land, supporting structures or gas-fired
2 back-up generation.

3 **Q. HOW DO YOU RESPOND DR. COOPER'S ASSERTION THAT**
4 **SOLAR PRICES ARE DECLINING?**

5 A. The prices quoted above are installed 2011 prices. PV solar prices
6 are declining, and at different site it would be possible to install more
7 efficient PV solar facilities than the thin-panel PV project described above.
8 However, these cost reductions and efficiency gains are incremental and
9 would not change the outcome of the analysis above in any meaningful
10 way.

11 **Q. WHAT WOULD A MORE EFFICIENT SOLAR INSTALLATION**
12 **COST?**

13 A. A PV solar panel array would be the leading alternative to thin
14 laminate technology for a green-field PV solar installation in our service
15 territory. In 2012 dollars, this technology costs \$4,947 per KW installed
16 according to EIA, including land costs and supporting buildings,
17 switchgear, and the like. Such an array would operate at a 16.4% capacity
18 factor in our area and produce 0.2 MW per acre at full capacity. Because of
19 how these panels are installed, an installation capable of replacing the
20 energy generated by SCE&G's share of the Units using this technology
21 would have a larger foot-print than a thin film installation. The PV solar

1 panel array would require a 34,511 acre installation at a cost of
2 approximately \$34 billion. The cost of gas generation to back stand such
3 an installation is not included in this figure.

4 **Q. HOW DO YOU RESPOND TO DR. COOPER'S SUGGESTION ON**
5 **P, 18-19 OF HIS TESTIMONY THAT LOWER DEMAND GROWTH**
6 **FORECASTS ON SCE&G'S ELECTRIC SYSTEM MAKE**
7 **NUCLEAR A LESS ATTRACTIVE OPTION THAN**
8 **ALTERNATIVES?**

9 A. I do not understand the logic of this argument. In fact, in its latest
10 integrated resource plan, SCE&G announced its plan to retire from service
11 730 MW of coal fired capacity in response to EPA air emissions
12 regulations. The nuclear capacity we are adding allows us to make these
13 retirements on a schedule that benefits customers by reducing the
14 investments we would otherwise be required to make in these plants.

15 **Q. HOW DO YOU RESPOND TO DR. COOPER'S ASSERTION ON P.**
16 **23 OF HIS TESTIMONY THAT IN THIS PROCEEDING "IT COSTS**
17 **ARE SHIFTED FROM UNIT 1?"**

18 A. This is not true. No shifting of cost is taking place. The costs of the
19 new IT technology that will serve Units 1, 2, and 3 will be allocated among
20 those Units using the appropriate allocation factors. Such allocations are
21 used routinely in accounting for costs and projects on our system and are

1 subject to review by the Commission and ORS. Unit 1 will bear its full
2 allocated share of the IT infrastructure upgrade it requires. This is clearly
3 stated in by Company's accounting witness, Ms. Walker, at page 15 of her
4 prefiled testimony: "Of course, Unit 1 will share an appropriate allocation
5 of the cost of the new IT infrastructure."

6 **Q. DR. COOPER SUGGESTS THAT ABANDONING CONSTRUCTION**
7 **OF THE UNITS WOULD SAVE CUSTOMERS MONEY, DO YOU**
8 **AGREE WITH HIS ANALYSIS?**

9 A. Mr. Marsh has discussed the faulty logic of Dr. Cooper's approach
10 to generation planning decisions. Based on my experience in the electric
11 generation business for over 25 years, I wholeheartedly agree with Mr.
12 Marsh. The sort of analysis that Dr. Cooper has done is far too simplistic to
13 represent a credible basis on which to make base load electric generation
14 decisions. His quality of analysis falls far below industry standards for
15 work on which utility planning decisions can be made.

16 In addition, I would note that Dr. Cooper's analysis does not factor
17 in the cost SCE&G and its customers would bear if the decision was made
18 to abandon this project in mid-construction. Those costs would be material.

19 **Q. WHAT WOULD BE INVOLVED IN ABANDONING THE**
20 **PROJECT?**

1 A. If SCE&G were to abandon the project, SCE&G would have to lay
2 off or if possible reassign most of its New Nuclear Development ("NND")
3 team. The exception would be the NND employees needed to supervise the
4 dismantling and securing of the site, who would continue to bill their labor
5 costs to the project for some time. Under the EPC Contract, we would
6 expect Westinghouse/Shaw to present us with a bill for any un-billed costs
7 to date. In addition, we would expect Westinghouse/Shaw to bill us for its
8 costs of demobilization, its cost of dismantling buildings and other work
9 done on site, its cost of winding down its contracts with suppliers and
10 contractors, its costs of terminating contracts for construction materials,
11 shipping contracts, and its lost margins. None of these costs have been
12 computed but they could be material. SCE&G would be allowed the
13 opportunity to attempt to sell for its account, parts and equipment under
14 manufacture and materials ordered and paid for by manufacturers at
15 whatever price the market would bear. SCE&G would be required to
16 stabilize the site and fill in excavations already completed. None of these
17 costs have been computed, nor has SCE&G studied the EPC Contract to
18 identify those areas in which it might dispute possible cost claims made by
19 Westinghouse/Shaw in this process. Nonetheless, the costs of abandoning
20 the project would increase the amount spent to date by a material number.

1 Q. AS AN ENGINEER WITH OVER 25 YEARS IN THE ELECTRIC
2 GENERATION BUSINESS, WOULD ABANDONING THE
3 PROJECT AT THIS STAGE MAKE SENSE?

4 A. It makes no sense at all to me to abandon a successful project that is
5 progressing well and is projected to come in approximately 8.7% below its
6 original projection. That would not be a prudent decision.

7 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

8 A. Yes, it does.

9

1 Commission's Fukushima response that required you to add
2 30 full-time equivalent -- I'm sorry -- 40 full-time
3 equivalent to emergency planning and health physics
4 people?

5 A Well, heretofore, we have used some responders from our
6 existing staff to handle emergency planning functions,
7 so I might have an operator or a mechanic that's a
8 member of a fire brigade, for example. The new
9 regulations are going to require that operators and
10 mechanics cannot have ancillary functions, and emergency
11 responders are going to have to be more dedicated. So
12 part of this is that we have a fire brigade now that's
13 going to have to be dedicated, manned round-the-clock
14 every shift, that doesn't have duties like they're an
15 operator of the plant, they're a mechanic of the plant.
16 So some of this is staffing requirements that are
17 increased because of the issues of Fukushima.

18 Q All right. So -- I was asked to put a mic on up here.
19 I'm not sure I'll -- excuse me. Does that work okay?

20 A Yes.

21 Q Okay. Does that work okay? And is this on
22 [indicating]? Yes. So, as I recall, as the Fukushima
23 accident was described, as it unfolded, because of the
24 loss of off-site power, there was a need to mobilize
25 considerable staff to do things like drag fire hoses and

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1 I don't know that that's found anywhere in the
2 record, as of yet, so --

3 MR. ZEIGLER: I was going to mention that at
4 the end of the --

5 MR. ELLIOTT: Well, and I --

6 MR. ZEIGLER: The version that the court
7 reporter has includes the slides --

8 MR. ELLIOTT: Right.

9 MR. ZEIGLER: -- as presented today.

10 MR. ELLIOTT: Right. Well, thank you. But it
11 was nagging me, so it's no longer nagging me. So
12 thank you, very much.

13 CHAIRMAN WRIGHT: All right.

14 CROSS EXAMINATION

15 BY MR. ELLIOTT:

16 Q All right. Let's -- to set the stage for my series of
17 questions, could you help me understand how we got here?
18 Now, we filed the Base Load Review Act application in
19 2008; Is that correct?

20 A That's correct.

21 Q And we got an order in 2009; is that correct?

22 A That's correct.

23 Q And in 2009, you came back in -- SCE&G came back in --
24 because you had to fix the scheduling, the construction
25 scheduling that we left hanging in the first docket. Do

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1 you recall that?

2 **A** We did have a supplemental docketed hearing for the
3 scheduling baseline, yes.

4 **Q** All right. So that was in 2009. And then you were back
5 in in 2010 for \$170 million or so?

6 **A** \$174 million, yes.

7 **Q** All right. And now we're here for another -- the math
8 is not my thing. 200-and-how-much?

9 **A** 283.

10 **Q** -- \$283 million. And so 2008, 2009, 2010, 2011, 2012.
11 So since the 2009 order, you've been in three more
12 times, about every year; is that correct?

13 **A** Since the start of the project? Or --

14 **Q** No, since you got the 2009 Base Load order, you've been
15 in here about every year since. Once a year since,
16 correct?

17 **A** Right, and we will be in every year with at least an
18 update.

19 **Q** Right. Now, going back to the initial application in
20 2008 -- and you'll have to help me with this, because
21 you were asked a lot of questions at the time by Mr.
22 Guild, and this is his area of expertise and I thought
23 he would follow up on it today, and so it will fall to
24 me. I was hoping he could save you and me some trouble.
25 But I think -- do I understand correctly that, when you

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1 filed in 2008, you filed with the fifteenth revision of
2 this AP1000 nuclear generator. Is that correct?

3 A I believe Rev 16 was the most current revision when we
4 filed.

5 Q Well, let's think about that. I think I recall your
6 testifying in response to some questioning from Mr.
7 Guild that there was a draft of 16 in existence when you
8 filed. Do you recall that?

9 A I don't recall it, and that could be the case. But I
10 believe that, when the design was certified in 2006,
11 that was through Rev 15, and they were either working on
12 or had been -- had approved 16. It may have been 17
13 that had been filed. You could be right.

14 Q It may be important, and I -- but I will follow up
15 before I start sifting through this paper. Would you
16 dispute my characterization of the facts that, at the
17 time of the 2008 hearing, the Version 15 had been
18 approved and that there was a draft version of 16, but
19 that the draft -- that it was only a draft, and 16 was
20 not approved until after the Base Load order?

21 A I don't recall that to be the case, but I'm sure we can
22 check on it.

23 MR. ELLIOTT: Well, let's do. Indulge me, Mr.
24 Chair. I'm looking, if I may -- and it's not that
25 important, but I think it's helpful to know.

1 Is this -- Madam Court Reporter, is there any
2 way to turn this off? I'd hate to damage it,
3 somehow.

4 MR. RICHARDSON: Damage this [indicating]?

5 MR. ELLIOTT: No, anything. Could we just
6 turn that off and let me have that nice blue
7 background?

8 MR. RICHARDSON: Let me try.

9 MR. ELLIOTT: Can we just turn it off, turn
10 the whole thing off?

11 MR. RICHARDSON: [Indicating.]

12 MR. ELLIOTT: Thank you.

13 BY MR. ELLIOTT:

14 Q I'm looking at page 679 of the transcript of the 2008
15 hearing, and I've highlighted some information. And
16 this is your testimony, and it says, "We are already
17 familiar with the new design and locked that into our
18 price with the EPC contract, so when it comes out with
19 Revision 16, our contract is already priced for that."
20 Do you recall that?

21 A Yes.

22 Q All right.

23 MS. GREENLAW: What page was that?

24 MR. ELLIOTT: 679.

25 <

1 BY MR. ELLIOTT:

2 Q All right. But I also think -- and you correct me if
3 I'm wrong -- that not only was 16 pending, but 17 was
4 pending by the time of that hearing, as well. Do you
5 recall that?

6 A I don't recall that.

7 Q All right. And the -- what you were granted a license
8 for was based on Revision 19, correct?

9 A That's correct.

10 Q So there would have been, I must assume, a Revision 18,
11 as well.

12 A There was an 18.

13 Q All right.

14 A I think there was a 17, but it got rolled into 18.

15 Q All right. And 16, 17, and 18 all had to do with the
16 strength of the shield, correct?

17 A I don't know that 16 had to do with the strength --
18 well, 16 may have incorporated the proposed Westinghouse
19 design for aircraft impact -- if that's what you mean,
20 the strength of the steel?

21 Q Yes, sir.

22 A Okay.

23 Q As I stated, this was Mr. Guild's specialty, and so I'm
24 struggling here. You're being very kind to me. And
25 what I understood was -- from that excerpt I read from

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1 your testimony from 2008 -- when you negotiated your EPC
2 contract with Westinghouse and all those, you
3 incorporated some costs from the draft 16 into the EPC
4 contract. You recall that?

5 A Yes

6 Q All right. Now, when we were here in 2008, you
7 acknowledged that there was some risk associated with a
8 delay in the schedule, based on a delay in your
9 obtaining that Combined Operating License. Do you
10 recall that?

11 A I believe that was in the attachment, and I think -- I
12 believe that we testified to that fact, yes.

13 Q All right, sir. And so you recognized that delay as a
14 risk that had to be dealt with, back in 2008. Correct?

15 A We recognized delay a risk, yes.

16 Q All right. And you recognized delay in getting your
17 license as a risk, to be clear, did you not?

18 A We did.

19 Q And so you took some precautionary measures to address
20 those risks. For instance, as we've just testified, you
21 built in the cost of the draft improvements to the
22 shield, in your EPC contract, correct?

23 A Correct.

24 Q And you also negotiated in your contract some penalties
25 that you could assess against Westinghouse and company

1 in the event of a delay, correct?

2 A Correct.

3 Q And, for instance, you testified in 2008 that, "In
4 addition, the Westinghouse/Stone & Webster consortium
5 agreed to commit contractually to the 2016 commercial
6 operation date for VCSNS Unit 2, with monetary penalties
7 for failure to meet that date." Do you recall
8 testifying to that?

9 A Yes.

10 Q And, in addition, in 2008 you testified, "Article 13 of
11 the EPC contract specifies liquidated damages that
12 Westinghouse/Stone & Webster will be responsible for if
13 there is a delay in the substantial completion date for
14 either unit." You recall that?

15 A Yes. Those -- this topic and the previous topic are
16 talking about the same thing.

17 Q All right, sir. And you go on to testify -- and I'm
18 omitting a sentence -- "Those delayed liquidated damages
19 accrue on a daily basis and are substantial." You
20 recall testifying to that?

21 A Yes.

22 Q Now, when you all were in here the last time in -- in
23 the hearing, at least, in 2011, it had become apparent
24 to SCE&G that a delay was going to occur, did it not?

25 A Probably sometime around that timeframe, yes.

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1 Q Well, I think you testified that Westinghouse had been
2 commissioned to do a study to determine the cost of
3 delay in receiving the COL and how to mitigate those
4 costs. Do you recall that?

5 A Yes.

6 Q And so what we now know is that Revision 16 was not
7 approved, correct?

8 A You're talking about --

9 Q Revision 16 was not the final revision to be approved,
10 correct?

11 A At the time of the original Base Load Review Act
12 hearing, is what you're saying?

13 Q That is what -- no, I'm saying Version 16 was not
14 approved as the final design, correct?

15 A It's not the final design, that's correct.

16 Q All right. and Version 17 was not approved as the
17 final design?

18 A That's correct.

19 Q Version 18 was not approved as the final design,
20 correct?

21 A Correct.

22 Q But Version 19 was approved in December of 2011. Do you
23 recall the exact date?

24 A It was late December. I think it was the 30th.

25 Q And, as a consequence, you are here -- SCE&G is here --

1 A If 16 were not approved? We anticipated 16 would be
2 approved.

3 Q But it was not. Correct?

4 A Well, 16 was eventually approved. Whether it gets
5 folded into a subsequent revision or it gets approved
6 stand-alone, the information is still approved.

7 Q All right. It was not approved in that form, to meet
8 the July 2011 deadline, which was a benchmark created by
9 the 2009 order, correct?

10 A Correct.

11 Q And you felt like you had addressed those risks, did you
12 not?

13 A We did feel that we had addressed the risk.

14 Q And among the ways you felt like you had addressed the
15 risks was that you felt like, and you informed the
16 Commission, that you could put any additional unexpected
17 costs to Westinghouse; you could require them to pay for
18 the additional costs associated with any delay or the
19 non-approval of 16.

20 A Are you asking me if we said that?

21 Q I'm asking you whether you felt like you addressed the
22 risks by having an EPC contract with Westinghouse where
23 they would be responsible for the delay costs.

24 A We did have an EPC contract where they were responsible
25 for delay costs. That does not shield you from all

1 risk.

2 Q All right.

3 A The delay is still a delay, and it's not a situation we
4 want to be in.

5 Q Well, we're going to -- let me just -- if we could just
6 talk a little bit about Westinghouse and their delay,
7 and then we'll talk about the other delay that I read
8 about in your testimony. So you had this EPC contract
9 where you felt like, if they caused a delay and it was
10 their fault, and you had additional costs, they would
11 have to pay penalties for it, correct?

12 A That's if the plant were to come on-line late. So, if
13 the commercial operation date were to be delayed, they
14 did have scheduled liquidated damages, correct.

15 Q All right. Now, when you went -- after the delay,
16 presumably after you got the COL in December, you began
17 negotiating with Westinghouse over whether they were
18 going to pay for the delay costs, did you not?

19 A We started that negotiation well in advance of December
20 and getting the Rev 19 issue, or March when we got the
21 COL issued to us.

22 Q And --

23 A That negotiation had been going on for quite some time.

24 Q And I thought you might have. But when you started
25 negotiation, it was apparent to everybody that you were

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1 A It wasn't their final claim. We had just reached that
2 point when we deemed we needed to make some financial
3 disclosures. So what we did was we put an upper bound
4 of \$188 million on the claims.

5 Q Okay. So the \$188 million was the upper bound of the
6 claim. Now, if I understand your testimony,
7 Westinghouse claimed that the EPC contract shielded them
8 from any liability. Do I understand that correctly?

9 A I'm not -- I don't recall Westinghouse making that
10 claim.

11 Q All right. Do you recall testifying that Westinghouse
12 asserted in your negotiations that they were -- that
13 because of uncontrollable circumstances, a term in your
14 EPC contract, they were not liable for any delay costs?

15 A They did try to make that claim, yes.

16 Q All right. And when you came in in 2008, you talked a
17 little bit about uncontrollable circumstances, as
18 defined by the EPC contract. Do you recall that?

19 A I don't recall -- I recall talking about it; I don't
20 recall specifically what I said.

21 Q All right. Do you have your rebuttal testimony?

22 A I do.

23 Q Would you look at Exhibit J, Chart A? I think that J is
24 like 12-of-12, if I recall the exchange between you and
25 Mr. Guild, and then there were a couple of charts. A is

1 a one-page chart; it immediately follows page 12-of-12.

2 A Chart A?

3 Q You see that?

4 A I have it.

5 Q Look at the very bottom please, number seven. You see
6 the words "Uncontrollable Circumstances"?

7 A I do.

8 Q What does it say?

9 A Severe weather; war/sabotage/terrorist attack.

10 Q All right. So that's your description in your -- in
11 this docket, but in your Exhibit J in the 2008
12 application, to describe uncontrollable circumstances.
13 Correct?

14 A That's correct.

15 Q But you do not describe uncontrollable circumstances as
16 a delay caused by a governmental agency where there is
17 no negligence or willfulness on the part of the person
18 seeking to use that doctrine, do you?

19 A That we described in this document? No.

20 Q Yes, sir. Now, so you have -- so, in essence, when you
21 came in in 2018_[sic] and appeared before this Commission,
22 in essence, what we now learn is that SCE&G bought
23 partial plans to a nuclear reactor, and the second
24 installment has come due now in the amount of \$137
25 million.

- 1 Q All right. And, in fact, part of the reason given --
- 2 A Or, 401 permit. Sorry.
- 3 Q Yes, sir. Part of the reason given by Westinghouse for
- 4 refusing to pay the delay damages was that your wetlands
- 5 permits were every bit as late as their Combined
- 6 Operating License permit; is that correct?
- 7 A They did try to make that assertion, yes.
- 8 Q All right. And so -- and these wetlands permits are
- 9 SCE&G's responsibility under their EPC, right?
- 10 A The permits are our responsibility, right.
- 11 Q All right. And so I need to understand how all this
- 12 works. What I understand, from your testimony, is that
- 13 at the time of the 2008 proceeding, SCE&G decided to use
- 14 a macro-corridor approach to siting their transmission
- 15 lines.
- 16 A Correct.
- 17 Q All right. And the way I understand this process to
- 18 work is that SCE&G would first apply to the Army Corps
- 19 of Engineers for their wetlands permits, correct?
- 20 A Correct.
- 21 Q And I think the Corps of Engineers, in essence, does the
- 22 groundwork -- if you'll pardon the pun -- and then, once
- 23 they have done an initial investigation or analysis,
- 24 then the application is turned over to the Environmental
- 25 Protection Agency. Is that correct?

1 A No, the EPA is really a coordinating agency. So what
2 the Corps did was they put out for comment to other
3 agencies. EPA was one of those -- but there were other
4 agencies -- that opted to make comments on the fact that
5 the macro-corridor approach, in their minds, was not
6 suitable, even though the Corps didn't have a problem
7 with it upfront.

8 Q All right. So the EPA, in essence, vetoed using the
9 macro-corridor approach and required you to do, what,
10 sir?

11 A To use a specific-corridor approach.

12 Q All right. Now, and that was the cause of some delay
13 in and of itself, correct?

14 A That's correct.

15 Q Now, that process that was employed is not unusual. I
16 mean, as I understand -- and I appreciate your
17 correcting me -- as I understand it, the Corps and EPA
18 and other agencies all work together to try to address
19 these issues, correct?

20 A That's correct.

21 Q So that worked as -- that functioned as it was required
22 to. Now, you did not -- you know, I'm a little confused
23 about macro corridors. This is the way I understand it
24 -- and I think I understand from your testimony, and I
25 understand it from reading Mr. Young's testimony. But

1 basically what you do is you look at a map, and I guess
2 it's -- I mean, I guess it's a fairly sophisticated map.
3 And you look at the map and you determine where on the
4 map you think it might be best for these transmission
5 lines to be put, and then you're able to somehow --
6 correct? You identify on a map where the transmission
7 lines go?

8 **A** Yeah, we'll identify a route, right.

9 **Q** All right. And then from that route, using these maps
10 that you have -- and Mr. Young can elaborate -- you're
11 able to identify wetlands issues, correct?

12 **A** Ones that we are aware of.

13 **Q** Yes.

14 **A** Yes.

15 **Q** And that's -- and your point is that, using the macro-
16 corridor approach, you can't identify all of them,
17 correct?

18 **A** That's correct.

19 **Q** All right. And so the purpose of the application is to
20 satisfy -- I believe -- the federal permitting agencies
21 and the State, I suppose, that you have considered the
22 wetlands issues and you're prepared to address them, and
23 you demonstrate how you intend to address them; is that
24 correct?

25 **A** That's correct.

1 Q And now, ultimately, you're going to have to put the
2 line somewhere and you're going to have to address the
3 wetlands issues, are you not?

4 A You are.

5 Q All right. So what SCE&G was hoping was that they could
6 use this sort of shorter version of siting to get the
7 permits maybe earlier or quicker; is that correct?

8 A It would've resulted in getting the wetlands permit more
9 expeditiously, yes.

10 Q All right. And I think when you were here and you
11 testified in the 2010 docket, you actually told me at
12 that time under cross-examination that you had changed
13 the -- you had changed your siting to go from new
14 transmission easements to the use of existing easements,
15 with maybe one exception; is that correct?

16 A Yeah. What we've done is we're using all existing
17 rights-of-way save for one six-mile segment.

18 Q All right. And I think there was some litigation over
19 that, maybe before this Commission. I somehow missed
20 that. But there was some litigation over that, before
21 the Commission, correct?

22 A There were hearings about it, yes.

23 Q All right. Yeah. And I think a settlement, I read in
24 somebody's testimony. Correct?

25 A That's correct.

1 Q And so, I mean, what we might infer from that is that
2 nobody really likes to have a new transmission line put
3 in his backyard, do they?

4 A Seemingly not.

5 Q Yes. And so -- and we talked a little bit about this in
6 2011 -- that's not a new concept. You knew in 2008 that
7 people were going to object to having a new transmission
8 line in their backyard, in 2008, did you?

9 A Yes. Siting transmission lines is never easy.

10 Q All right.

11 A The macro-corridor approach is an approach that we have
12 used in the past and was used by Southern Company in the
13 Vogtle project.

14 Q All right. Well, now, let's talk about this. I think
15 in 2008 you told me that contingency funds were funds
16 that you had used in construction projects in the past.
17 Do you recall that?

18 A Do we use contingency on our projects, in construction
19 projects? We do.

20 Q Yes, sir. Yes, sir. And I think we learned from the
21 Supreme Court, as a result of that hearing, that just
22 because you used contingency funds in the past doesn't
23 necessarily mean you can use them under the Base Load
24 Review Act. Didn't we learn that, sir?

25 A I'm not sure that's what we learned. I know that we

1 don't have contingencies associated with the Base Load
2 Review Act anymore.

3 **Q** Okay. I'll accept that. Thank you. And so my point
4 is, sir, just because you've used a shortcut version of
5 siting in the past doesn't necessarily mean that it
6 would be something that would be appropriate to use
7 under the Base Load Review Act, does it?

8 **A** I wouldn't characterize it as a shortcut siting. It's a
9 technique that we have used and other companies have
10 used successfully here in the Southeast. So I don't
11 know that it's a shortcut. What you're doing is you're
12 saying that "This is the corridor I'm going to use for
13 the purposes of getting the macro permit," but then as
14 you discover either wetlands or historical sites or
15 other things, you will mitigate those or change the
16 route as you go down that path.

17 **Q** Well, the alternative to the macro-corridor approach
18 would be for you to have identified the routes and
19 walked them, and identified all of the wetlands issues
20 for the EPA, which was obviously eager to know about
21 them, wouldn't it?

22 **A** No. It's a little more complicated than simply walking
23 the routes, and there are more issues you have to
24 account for than simply wetlands issues. But what the
25 macro-corridor approach says is, in this swath of

1 property, if I run into an issue going straight, I can
2 go to the right or go to the left and then continue
3 going straight.

4 Q So it sounds like, to me, the macro-corridor approach is
5 a shorter process?

6 A Well, in the long run, it's not going to be a shorter
7 process. You're still going to purchase the property,
8 you're still going to have to get the easements, you're
9 still going to have to mitigate what you find --

10 Q And --

11 A -- or compensate for it by going around.

12 Q Excuse me.

13 A So it's not necessarily going to be a shorter process.
14 It would get us to the point of getting the permits, the
15 wetlands permit, earlier.

16 Q Now, you -- what you decided to do after the EPA refused
17 to -- oh, and I should ask you, too, because you
18 mentioned Vogtle. Now, as I understand it, you don't
19 work for Vogtle.

20 A I do not.

21 Q All right. And you are not familiar with their -- you
22 didn't plan their transmission siting design, did you?

23 A I did not plan their --

24 Q All right.

25 A -- transmission --

1 Q So --

2 A -- siting design.

3 Q So whatever you know about Vogtle, you know because
4 somebody else told you or was something you read?

5 A Or we've had direct contact with the folks at Southern.

6 Q So they told you?

7 A They told me.

8 Q Yeah, okay. So it's hearsay. Now, I asked you last
9 year about using these existing right-of-ways. And as I
10 understand it, with the exception of that one six-mile
11 stretch, you're going to use your existing right-of-
12 ways, correct?

13 A That's correct.

14 Q And you had these -- these right-of-ways were in
15 existence, and were your right-of-ways in 2008, when you
16 came in here before the Commission and submitted your
17 Base Load application, correct?

18 A They were our right-of-ways, yes.

19 Q And so that would've been an option you could've used
20 for siting transmission lines -- an option that you
21 could have used in 2008, correct?

22 A It's one option we could have considered, yes.

23 Q Right. And so we now know of at least three options:
24 You could have used the macro option, you could have
25 determined what the lines were and examined them and

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1 investigated them, or you could have used existing
2 rights-of-way that you already had and you already knew
3 about the wetlands issues, correct?

4 A We could have.

5 Q All right. And there are probably others, aren't there,
6 sir?

7 A Yeah, it's not necessarily a foregone conclusion that
8 just because you have existing right-of-way, you won't
9 have any wetlands or historical site issues.

10 Q All right, sir. And so what happened was you took --
11 you used this macro process, this shorter process, and
12 you first submitted that to the Corps of Engineers, and
13 that was rejected, correct?

14 A No. The Corps informed us that they were fine with that
15 process. It's when they got comments from coordinating
16 agencies that they changed their mind.

17 Q Okay. Who may we say rejected it? May we say the Corps
18 rejected it? May we say EPA? I'm just curious as to
19 who you put the --

20 A What you asked me was, when we first submitted it,
21 submitted the macro-corridor process to the Corps, if
22 they rejected it. No, they first accepted it, but then
23 they took comments from coordinating agencies and asked
24 us to do a specific siting plan for the transmission
25 lines.

1 Q The Corps asked you to do that.

2 A Correct

3 Q All right. So it's the Corps. All right. And so you
4 shifted over to your existing easements, but not in time
5 to meet a July 2011 milestone, correct?

6 A Correct. We did have some discussions with the Corps,
7 because there was no reason for it to take as long as it
8 did, and they let us know that they were aware of the
9 fact that the COL was being delayed. So there was an
10 opportunity for us to try to expedite that, but they
11 didn't see any reason to expedite it since the COL was
12 not going to come until later.

13 Q And do you know how much money you spent trying to
14 promote this macro process?

15 A Do I know how much money we spent trying to promote it?

16 Q To advance it, to --

17 A No.

18 Q -- apply for approval? So at the end of the day, you
19 didn't get your permit -- you didn't get your wetlands
20 permits any sooner than you got your COL, correct?

21 A No, we got the wetlands permit prior to the COL.

22 Q All right. A week or two. It was in December, right?

23 A No, it was -- we got the wetlands permit in December;
24 the COL came in March. So it was about three months.

25 Q I beg your pardon. You didn't -- you got your -- the

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1 Revision 19 was approved about the same time as the
2 wetlands.

3 A Revision 19 was --

4 Q Thank you.

5 A -- approved about the same time of the wetlands permit.

6 Q I stand corrected. Thank you. And so when you went to
7 negotiate with Westinghouse over their \$188 million
8 payment demand, they told you two things. First they
9 told you that uncontrolled -- uncontrollable
10 circumstances prevented them from having to pay the
11 extra costs, and that you -- SCE&G was going to have to
12 pay it, correct?

13 A Well, first of all, it was higher than \$188 million.
14 And they did make a case -- they made a lot of arguments
15 as to why they should not be held responsible for these
16 charges and we should have to pay for them. One of
17 their arguments was uncontrollable circumstance, but not
18 in the classical sense. There are provisions in our
19 contract, like most, about changes in interpretation
20 and/or changes in the law. So they viewed this as a
21 change in the regulation.

22 Q All right. And then they also threw up the defense that
23 it didn't matter whether the Combined Operating License
24 was approved before December of 2011, because you didn't
25 have the wetlands permits, correct?

1 A That was an argument they tried to put forth, yes.

2 Q And the fact of the matter is that, if you had just used
3 the public easements to begin with, you would've had the
4 wetlands permits in hand by July 2011, wouldn't you,
5 sir?

6 A I don't know that to be the case, no. And there was
7 nothing wrong with the macro-corridor approach that we
8 opted to use, that we have used successfully in the
9 past.

10 Q Well, except for, in this case, it contributes to your
11 being here asking the ratepayers to pay \$137 million for
12 these costs that were the direct result of your
13 application in 2008, based on a draft of the sixteenth
14 revision of the nuclear generating plant plan, wasn't
15 it?

16 A I'm not sure I understood the question.

17 Q Well, these costs -- these -- your delay in getting the
18 -- your delay in obtaining your wetlands permits gave
19 rise to Westinghouse saying that you were negligent in
20 failing to get the permits on time, correct?

21 A It gave rise to an argument they used.

22 Q And so you're here seeking \$137 million from your
23 ratepayers to pay for those extra costs, are you not?

24 A We are here seeking \$137½ million to pay for those
25 settlement charges that are the result of a negotiation

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1 existing rights-of-way, you'd have gotten your wetlands
2 permit on time, wouldn't you?

3 A I don't know that we would have gotten a wetlands permit
4 on time. The Corps was very slow in responding to the
5 wetlands issues, and they did get feedback from other
6 cooperating agencies. I don't know that they would not
7 have had some other issue, had the macro-corridor
8 approach not been utilized. And again, we had no reason
9 to believe that the macro-corridor approach would not be
10 accepted, because we have used it successfully in this
11 State in the past, dealing with the same branch of the
12 Army Corps of Engineers.

13 Q For construction, in the last thirty or forty years, of
14 a nuclear plant?

15 A It wasn't a nuclear plant, but the transmission
16 corridors don't make any difference. It wasn't the fact
17 that it was a nuclear plant that caused any issues.

18 Q And so your testimony is that SCE&G was not at all
19 negligent in obtaining its own easements -- wetlands
20 permits for those easements?

21 A That is my testimony.

22 Q And your testimony is that you argued, just as
23 Westinghouse did, that uncontrolled circumstances would
24 have protected you against having to pay for the delay.

25 A I'm not making the tie to the easements and

1 new shield design that involved a construction technique
2 new to US regulators -- and I didn't see much about a
3 technique, just more about the construction, that it had
4 steel cladding on what Japanese and Koreans had been
5 putting in for over 15 years on structures other than
6 the actual containment building. So, you knew that this
7 could've been incorporated in your design since the
8 World Center attack, but you chose not to update your
9 design on your own, is that correct, or didn't ask
10 Westinghouse to?

11 A I'm not sure I'm following you. The design is -- what
12 they call steel clad is basically concrete between two
13 relatively thick layers of steel, with supports in
14 between, which is a departure from the traditional
15 design, which is just the concrete with reinforcing bar
16 in between. That design has not been used in design for
17 US power plants in this country, heretofore. It has
18 been used in some power plants in some other countries.
19 So, the Westinghouse experience with that comes from
20 those other countries. The US regulator said there were
21 no codes and standards for that application in this
22 country, and wanted Westinghouse to prove the design,
23 which is why they went through that exhaustive testing
24 program with Purdue University.

25 Q Right, okay. Now, is that part of the increase in fees

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1 Q Are these payments for the revision design, like
2 Revision 19, or to whom are these payments going?

3 A No, these are going to be payments to the consortium,
4 and this gets -- really, it's a Westinghouse charge.
5 But those would be payments for hitting certain
6 milestones in the design. And these are things that
7 were -- they hit their milestone in 2009.

8 Q Okay.

9 A So 33 was a design finalization milestone payment that
10 was made in 2009.

11 Q Are these also confidential numbers?

12 A Likely, but I don't have any idea what that is.

13 Q Okay. That's all right. Okay. All right. I want to
14 ask about these delays. Earlier in my opening statement
15 I was curious as to why Westinghouse needed compensation
16 for errors or for, you know, what you all had to settle
17 on. And again, I'm wondering why the public should pay
18 anything, because it seems to me that both of you -- you
19 and Westinghouse -- were equally at fault for not having
20 proper projections and for planning ahead. So I'm not
21 sure where I'm going with that as a question, but I
22 understand the redesign of certain modules, I understand
23 the redesign of the shield building, I understand the
24 rock conditions. I have no earthly idea what is meant
25 by delay in COL issuance. Would you explain that to me?

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1 A Sure. Originally, we had foreseen that we were going to
2 get the COL, or the license, issued in July of 2011.

3 Q You saw that from what?

4 A We got an original schedule from the Nuclear Regulatory
5 Commission based on our design and understanding when we
6 would be submitting our application. That date that we
7 got from the NRC was a contractual date, so --

8 Q Well, wait, wait. I'm sorry. They give you a
9 contractual date by which they were going to give you
10 this COL?

11 A Let me be clear.

12 Q Okay, please.

13 A We got a date from the Nuclear Regulatory Commission as
14 to when they estimated they would get us a COL. We then
15 negotiated the contract with Westinghouse/Shaw and they
16 wanted -- we had to have some basis for saying when you
17 would get the license issued to you. We used the
18 Nuclear Regulatory Commission date as the date that we
19 would put in the contract. So, it wasn't a contract
20 with the NRC; this was our EPC contract with the
21 consortium.

22 So that anticipated, again, that the COL would be
23 issued to us in July of 2011. The COL did not get
24 issued to us until March of 2012. So there was a delay
25 in issuance of the COL.

1 Q Okay. Well, I had asked you in my discovery questions,
2 in reference to, you know, page seven of your direct
3 testimony, item 24, what agreement or assurance was
4 given -- what written agreement or assurance was given
5 by the NRC to SCE&G or to Westinghouse concerning the
6 real, probable deadline by which the company could
7 expect final approval on the AP1000 as the date of that
8 agreement. And the response I got from the company is
9 that the NRC didn't provide written assurance that the
10 design control document or COL would be approved, nor
11 did they provide a specific date for that decision. So
12 the response I got from the company is not what you --

13 A They did not provide any guarantees or assurances. They
14 give us a schedule date. That's all they gave us. So
15 there was no assurance. You know, the NRC couldn't be
16 held liable for that.

17 Q Correct. They shouldn't be held liable, because they do
18 a thorough job, do they not?

19 A That's correct.

20 Q Okay. So they gave you a ballpark date?

21 A That's right.

22 Q And they told you that was July 2011?

23 A They gave us a schedule estimate of July 2011.

24 Q And did they base that on your schedule? Did they look
25 at your milestones and say, "Oh, yeah, we can hit your

1 milestone"?

2 A They did not look at our milestones; they looked at
3 their milestones. They -- our milestones really didn't
4 have any bearing on when they would estimate that they
5 could do the reviews and turn that around into a
6 license.

7 Q Is this before there was a new NRC board?

8 A Was it before --

9 Q Which NRC board was this?

10 A You talking about --

11 Q Jaczko was Chair; is that correct?

12 A Jaczko was the Chair at that time, that's correct.

13 Q And there have been changes since that time?

14 A Not up to the point when we got our COL.

15 Q Ah, okay.

16 A The changes to the Commission came after we got our COL
17 issued.

18 Q When they gave you this date, they said, you know, "This
19 could work for us," but what caveats did they give you?

20 A I don't recall what caveats they gave us.

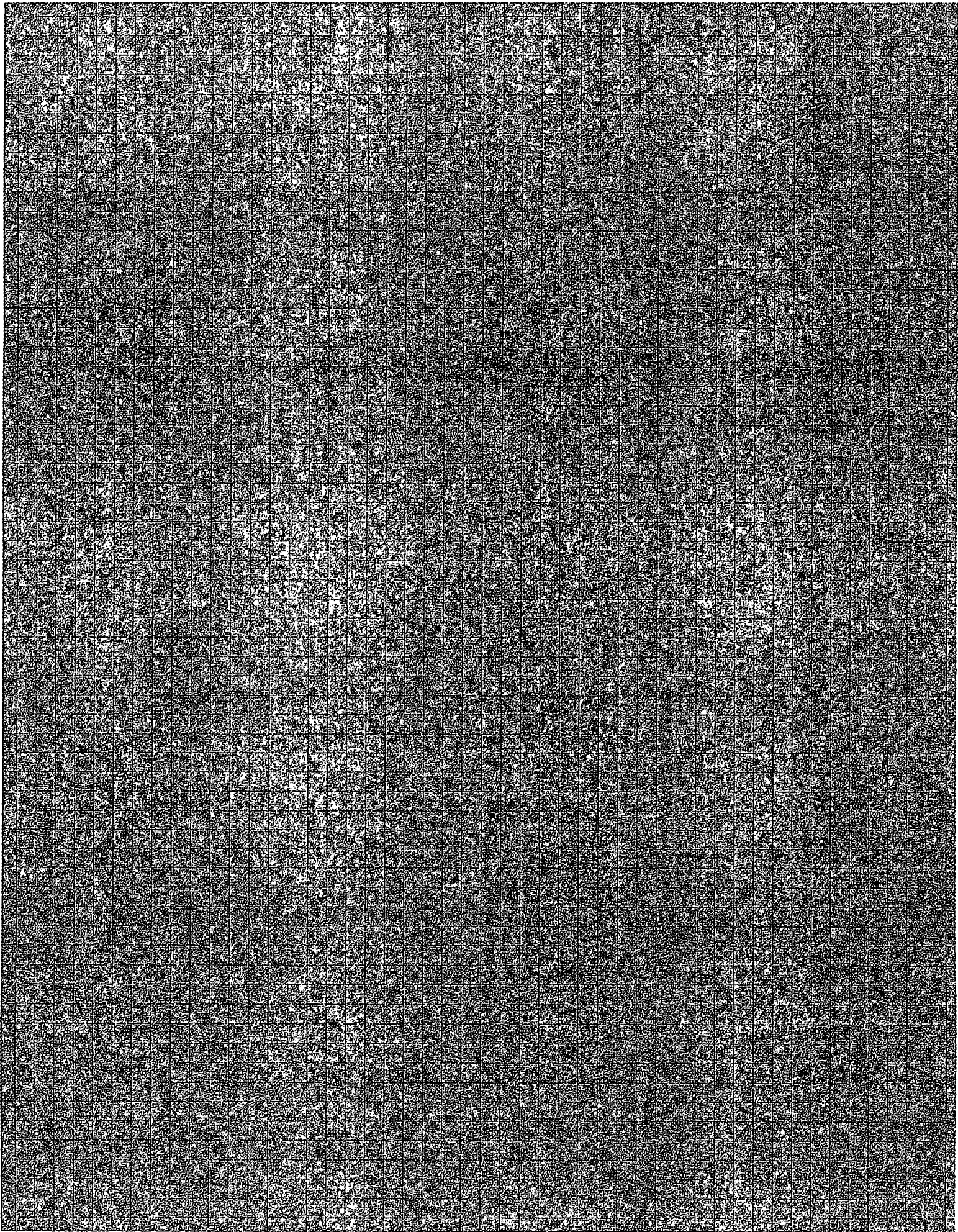
21 Q Would someone recall that? Should I ask this question
22 of someone else?

23 A I don't think anybody here was involved with any
24 discussions with the NRC of our schedule.

25 Q It was only you?

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

HEARING # 12-11315

OCTOBER 3, 2012

9:30 A.M.

DOCKET NO. 2012-203-E:

SOUTH CAROLINA ELECTRIC & GAS COMPANY - Petition for Updates and Revisions to Schedules Related to the Construction of a Nuclear Base Load Generation Facility at Jenkinsville, South Carolina

TRANSCRIPT OF TESTIMONY
AND PROCEEDINGS

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HEARING BEFORE: David A. WRIGHT, *CHAIRMAN*, Randy MITCHELL, *VICE CHAIRMAN*; and COMMISSIONERS John E. 'Butch' HOWARD, G. O'Neal HAMILTON, Elizabeth B. 'Lib' FLEMING, Swain E. WHITFIELD, and Nikiya 'Nikki' HALL

ADVISOR TO COMMISSION: F. David Butler, Esq.

STAFF: Joseph Melchers, General Counsel; James Spearman, Ph.D., Executive Assistant to Commissioners; David Stark, Esq., Legal Staff; Tom Ellison and Lynn Ballentine, Advisory Staff; Jo Elizabeth M. Wheat, CVR-CM/M-GNSC, Court Reporter; and Colanthia Alvarez and Dale Davis, Hearing Room Assistants

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• PowerPoint presentation [PDF] of Dr. Cooper	

P R O C E E D I N G S

CHAIRMAN WRIGHT: Please be seated. Well, good morning to everyone. I hope you had a good night's rest. We're going to try to push through this today. I think -- just to give you some idea, we've got a Commission meeting at 2 o'clock today, so what we'll do is push to about 1 o'clock, break for lunch at that point, and then we'll come back and do the Commission meeting, and we'll resume the hearing as soon as that meeting is over, if that works with everybody. Probably we'll look at taking a break at, I'm guessing, around 11-ish, depending on our court reporter and how she's feeling.

So we'll pick it up from where we left off, so where were we last night? Company, I think your next witness is ready.

MR. GISSENDANNER: SCE&G calls David Lavigne to the stand.

CHAIRMAN WRIGHT: Good morning.

MR. LAVIGNE: [Nodding head.]

[Witness sworn]

THEREUPON came,

DAVID A. LAVIGNE,
called as a witness on behalf of the Petitioner, South

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1 Carolina Electric & Gas Company, who, having been first duly
2 sworn, was examined and testified as follows:

3 **DIRECT EXAMINATION**

4 **BY MR. GISSENDANNER:**

5 **Q** Please state your name for the record.

6 **A** My name is David Lavigne.

7 **Q** And by whom are you employed and in what capacity?

8 **A** I'm employed by South Carolina Electric & Gas. I'm the
9 general manager of Operational Readiness for the New
10 Nuclear Deployment.

11 **Q** And, Mr. Lavigne, have you prepared or caused to be
12 prepared under your supervision direct testimony of 18
13 pages that was previously filed with the Commission in
14 this docket?

15 **A** I have.

16 **Q** Do you have any changes or additions to your prefiled
17 testimony?

18 **A** I do not.

19 **Q** And if I asked you the same questions here today, would
20 your answers be the same?

21 **A** They would.

22 **MR. GISSENDANNER:** Mr. Chairman, at this time,
23 I'll move that the prefiled direct testimony of Mr.
24 David Lavigne be read into the record as if given
25 orally from the stand.

1 **CHAIRMAN WRIGHT:** The direct testimony of
2 David Lavigne will be entered into the record as if
3 given orally from the stand.

4 *[See pgs 555-572]*

5 **BY MR. GISSENDANNER:**

6 **Q** And, Mr. Lavigne, have you prepared or caused to be
7 prepared under your supervision one exhibit labeled as
8 Exhibit DAL-1, that was previously filed with the
9 Commission as an attachment to your direct testimony in
10 this docket?

11 **A** I have.

12 **Q** And do you have any changes or additions to that
13 exhibit?

14 **A** I do not.

15 **MR. GISSENDANNER:** Mr. Chairman, I would also
16 move into the record, as the next hearing exhibit,
17 the exhibit attached to Mr. Lavigne's direct
18 testimony and labeled as Exhibit DAL-1.

19 **CHAIRMAN WRIGHT:** Mr. Lavigne's Exhibit DAL-1
20 will be entered as Exhibit No. 4.

21 *[WHEREUPON, Hearing Exhibit No. 4 was*
22 *marked and received in evidence.]*

23 **BY MR. GISSENDANNER:**

24 **Q** Mr. Lavigne, have you prepared a summary of your direct
25 testimony?