STATE OF CALIFORNIA Edmund G. Brown Jr., Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

January 24, 2012

To: Parties to CPUC proceeding A.10-11-010 – Sale of SCE share of Four Corners Generating Station

From: Andrew Barnsdale, Project Manager
Energy Division CEQA Unit

Re: Final Initial Study and Negative Declaration, and Response to Comments

Attached please find the Final Initial Study and Negative Declaration for the sale of Southern California Edison's share of ownership in the Four Corners Generating Station in New Mexico.

Although not required by the California Environmental Quality Act, the Commission's Energy Division has also prepared a Response-to-Comment memorandum in order to facilitate parties' understanding of the Commission's approach and methodology in this proceeding. This Response-to-Comment memorandum is attached as well.

The Energy Division intends to have these documents posted to our website within 24 hours.

MEMORANDUM

Date:	January 24, 2012
To:	Mr. Andrew Barnsdale, California Public Utilities Commission
Cc:	Ryan Stevenson, Southern California Edison Pamela Campos and Tim O'Connor, Environmental Defense Fund Suma Peesapati, Earthjustice Dr. Petra Pless, Pless Environmental Consulting Nicole Horseherder, To' Nizhoni Ani Anna Frazer, Diné Citizens Against Ruining Our Environment
From:	Panorama Environmental, Inc.
Project:	Four Corners Generating Station Project
Subject:	Response to Comments Received on the Draft IS/ND

1. INTRODUCTION

1.1 PURPOSE OF MEMORANDUM

This memorandum has been prepared to present the California Public Utilities Commission's response to comments received on the Draft Initial Study and Negative Declaration (IS/ND) for the Four Corners Generation Station Project.

1.2 PROJECT SUMMARY

Southern California Edison Company (SCE), a regulated California utility, has proposed to sell its ownership share of the Four Corners Generating Station (Four Corners) located in northwestern New Mexico. The Four Corners facility power plant fuel source is coal, which is burned to heat water and make steam in a thermal plant. The plant is co-owned by SCE and five other utility companies as tenants-in-common.

1.3 ENVIRONMENTAL REVIEW PROCESS

The CPUC must determine whether to authorize the proposed sale. The CPUC prepared a Draft IS/ND for the purpose of examining the potential environmental impacts associated with the proposed project prior to making a decision. The Draft IS/ND was circulated for public review from September 27, 2011, through November 3, 2011. The purpose of the review period was to allow the public and agencies to comment on the adequacy of the Draft IS/ND.

Four comment letters were received during the public review period. The four comment letters are attached herein and the responses to these comments are addressed in this memorandum. Any changes to the Draft IS/ND resulting from text revisions from consideration of comments have been included in the Final IS/ND and are shown in ~~strikethrough~~ and underline within the revised text of the document.

The edits made in response to comments did not trigger the need for recirculation of the IS/ND per the California Environmental Quality Act (CEQA) Guidelines Section 15073.5. No new avoidable or unavoidable significant effects were identified and no new mitigation measures to address new avoidable effects were added. In accordance with CEQA Guidelines Section 15074.1, none of the changes made to the IS/ND require recirculation of the IS/ND.

2. COMMENT DISCUSSION

2.1 COMMENTS RECEIVED

Four comment letters were received on the proposed project from the following organizations and agencies:

- Southern California Edison (SCE)
- Environmental Defense Fund
- Earthjustice on behalf of the Sierra Club
- Pless Environmental Consulting

In addition, the following organizations requested to be added as signatories to the comment letter from Earthjustice:

- To' Nizhoni Ani
- Diné Citizens Against Ruining Our Environment (Diné CARE)

2.2 FORMAT OF RESPONSE TO COMMENTS

This response to comments is divided into two sections: Master Comments and Responses, and Individual Comments and Responses. The predominant issues and concerns that were stated in the comments are summarized and responded to in a Master Comment and Response format in section 2.3 of this memorandum. Individual comments have also been addressed in Section 2.4. Each comment is identified by a letter and a number, and the responses to each comment immediately follow the letter. A reference to the Master Responses is made, where appropriate, in the individual responses. Responses are focused on the comments made on environmental issues.

2.3 MASTER COMMENTS AND RESPONSES

2.3.1 SUMMARY OF KEY CONCERNS

Key concerns raised during the public review period included comments on:

- Project description
  - Scenarios
  - Consideration of plant modifications
  - Consideration of transmission line divestiture
- CEQA thresholds
- Cumulative analysis
- Supporting documentation
  - References
  - GHG calculations
- National Environmental Policy Act (NEPA) review
- Preparation of an Environmental Impact Report (EIR)

2.3.2 PROJECT DESCRIPTION

Comments

Several comments were made on the adequacy of the project description and the scenarios presented in the project description. The key comments were as follows:

1. The capital improvements made to the Four Corners Generating Station by SCE in 2007-2011, as well as the capital improvements currently proposed by SCE, are part of the sale and should be considered as part of the project under CEQA. The modifications would increase the GHG emissions of Units 4 and 5 by increasing capacity, efficiency, and reliability beyond the facility's historic capacity factor. Even a small efficiency and reliability increase beyond the historic capacity factor would result in a significant increase in GHG emissions. The Draft IS/ND fails to provide any evidence supporting the claim that the proposed capital improvements are exempt from review under CEQA. The improvements should be part of the project description and should be analyzed in the impacts discussion.
2. The scenarios are flawed and therefore, the IS/ND lacks an adequate project description. The scenarios and resulting analysis rely on APS shutting down Units 1-3 as proposed in a letter to the EPA, and the shutting down of these three units is neither guaranteed by APS nor enforceable by SCE. The definition of the project is therefore illegal. In addition, even if Units 1-3 are shut down by APS, it is unlikely that these units would be shut down prior to the completion of the sale; APS would almost certainly have possession of SCE's share of Units 4 and 5 for some time before Units 1-3 would be shut down. Temporary impacts are not exempt from CEQA.

3. The Draft IS/ND fails to address potential environmental impacts associated with SCE's agreement to terminate its interest in energy transmission rights associated with the Four Corners facility. It is possible that SCE's termination of its transmission rights would make the delivery of renewable energy more difficult and expensive, which incentivizes additional fossil fuel based energy generation and transmission and therefore increases GHGs. The project description and analysis of effects should address the termination of those transmission rights by SCE.

Responses

1. The proposed capital improvements would not result in the increase in GHG emissions and would not have impacts on California; therefore, the improvements were not considered as part of the project. Improvements made from 2007 through 2011 are considered baseline conditions under CEQA. CEQA only requires the evaluation of impacts over the baseline condition. However, based on SCE testimony and filing in SCE's Test Year 2012 General Rate Case, SCE demonstrated that none of the 2007-2011 projects caused any material variation in the historical capacity factors of Units 4 and 5 (SCE-17, Vol. 6, Part 2, pp. 21, 24). The largest projects allowed Units 4 and 5 to generate more megawatt output for the same amount of coal/steam input. SCE's rebuttal testimony established that none of the referenced projects caused, nor could they cause, the GHG emissions from Units 4 and 5 to increase. Future projects proposed for 2012-2014 would likewise not result in the increase of fuel use or an increase in the historical capacity factors of Units 4 and 5 (SCE-17, Vol. 6, Part 2, pp. 21, 24). Since these improvements would not have an impact on GHG emissions, which are the only impacts relevant to California, they are not considered further in the IS/ND.

   Appendix C to the Draft IS/ND includes a table of the average net output in MW of each unit from the year 2000 through 2010. The MW output of Units 4 and 5 remained within the historic output over the previous 7 years, even with improvements implemented from 2007 through 2011 (through 2010 shown in the table).

   Text has been revised in the IS/ND to include the additional reasons as to why the improvements are not considered part of the CEQA analysis.

2. The CPUC maintains that the scenarios are adequate; however, some modifications to Scenarios 2 and 3 have been made. Scenario 2 has been revised to reflect certain facts stated in the testimony before the PUC for SCE's Test Year 2012 General Rate Case. Scenario 2 includes an increase in average output on Units 4 and 5 based on operation near full rated load, without ever incurring outages for maintenance. This portion of the scenario has been removed since it is unrealistic and testimony has been made to the effect that it would not occur. This change would have resulted in Scenario 2 being identical to Scenario 1; therefore, for the Final IS/ND, Scenario 2 has been further modified to assume Units 1-3 remain operational after the sale is complete. Scenario 2 in the Final IS/ND demonstrates how the continued permanent or temporary operation of Units 1-3 would still result in a net reduction in GHG emissions resulting from the project.

Modifications have also been made to Scenario 3. The scenario has been revised to state that the scenario is also rejected because the increase in average output based on operation near full rated load, without ever incurring outages, is unrealistic.

The comments regarding the enforceability of the shutdown of Units 1-3 are noted. While the shutdown of Units 1-3 by APS cannot be enforced by the CPUC, the assumption that the units will be closed is reasonable based on statements made publicly by APS, as well as in their proposal to EPA; based on the costs associated with installing EPA required emissions controls on Units 1-3 versus the cost of buying SCE's capacity to make up for the loss of capacity through the closure of Units 1-3 (Power 2010); and based on the fact that the sale of SCE's interest in the Four Corners facility would not change or induce the increase in electricity demand overall. However, an increase in GHGs above the baseline condition would not occur whether or not Units 1-3 are shut down since the historic capacity factor of Units 4 and 5 would not change. The overall emissions of GHGs from the Four Corners facility after the sale would be less than the "baseline condition" of current operation before the sale.

It is acknowledged that APS could shutdown existing natural gas facilities that emit less GHGs than the Four Corners Facility to utilize the additional capacity at Four Corners from the sale, and it is in fact assumed in scenarios 1 and 2 that APS would shut down natural gas facilities to balance the increase in its share of the Four Corners energy generation. However, the overall emissions of GHGs would decrease compared with current conditions. SCE would lose access to approximately 588 MW of energy as the result of the sale and would need to obtain an equivalent amount of replacement energy to continue to meet customer demand in California. SCE would need to obtain Emissions Performance Standard (EPS)-compliant energy, which would likely involve energy produced from natural gas. Similarly, APS would obtain a surplus of 588 MW of energy as a result of the sale (without shutdown of Units 1-3, or 103 MW if Units 1-3 are shutdown), and could scale back an equivalent amount of energy production elsewhere in its system to balance its energy production. Due to California's EPS requirements, the replacement natural gas-powered energy acquired by SCE would have lower GHG emissions than the natural gas-powered energy scaled back by APS, resulting in a net reduction in GHG emissions. The new energy generation by SCE would likely come from natural gas-powered energy, which would have a greenhouse gas emission rate no greater than 1,100 lbs/MWhr (the minimally compliant emissions rate under the current EPS) (CPUC 2007). The average greenhouse gas emissions rate for generic natural gas-powered facilities in the APS system is higher than the maximum emission rate for a California facility at 1,175 lbs/MWhr (CCAR 2009). The analysis of the IS/ND has been revised to include additional clarification of the GHG impacts.

3. The transmission line rights owned by SCE are currently used for the transmission of coal-generated energy from the Four Corners facility to SCE's customers in California. Once SCE sells these transmission rights to APS, this transmission capacity could continue to be used to transmit energy from the Four Corners facility to other locations (other than California) or it could be used to transmit energy from other sources, including renewable energy sources. CEQA requires analysis of effects above the

baseline condition. The baseline condition is the transmission of power generated by a coal facility. If the transmission capacity is used in the future by APS to transmit coal-powered energy, then there is no change in GHG emission impacts over the existing, baseline condition. If, on the other hand, the transmission capacity is used in the future by APS for natural gas-powered energy or renewable energy, then there would be a possibility that GHG emissions could decrease.

2.3.3 CEQA THRESHOLDS

Comment

The Draft IS/ND fails to provide a quantitative threshold of significance for GHG emissions. The threshold in this scenario should be zero, because the sale is based on SB 1368, a legislative mandate to reduce California's contribution to climate change in the context of electricity generation and consumption.

Response

The Four Corners facility is located on federal land and no GHG significance thresholds have been established under federal law. Several Air Pollution Control Districts (APCDs) within California have established significance thresholds for GHGs. The Four Corners Generating Station is not located in California; therefore, the significance thresholds established by California APCDs would not directly apply to this project. Although there are no directly applicable significance thresholds, the net GHG emissions could be compared to the interim thresholds established by the South Coast Air Quality Management District (SCAQMD). The SCAQMD thresholds were chosen as an appropriate significance threshold to use for comparison purposes since SCE power plants typically operate within this AQMD.

The SCAQMD staff developed a draft significance threshold that is based on a tiered approach (SCAQMD, *Interim CEQA Greenhouse Gas Significance Threshold*, Oct. 2008). The SCAQMD non-CEQA exempt Tier 2 threshold is 10,000 metric tons per year CO_2 equivalent. Projects exceeding that amount go to Tier 3, which incorporates various options for GHG emissions reduction (30 percent from "business as usual", or achieving "sector-based standards" reductions). The SCAQMD Tier 2 significance threshold does not consider separately the industrial sector or power plants; however, this threshold is presented here to provide a reasonable numerical threshold for impact significance discussion purposes. The threshold and a discussion of how the threshold was chosen has been clarified in the IS/ND.

The discussion of a significance threshold for this project is ultimately irrelevant, however, as the proposed project would result in a net decrease in GHG emissions.

2.3.4 CUMULATIVE ANALYSIS

Comments

Commenters noted that the Draft IS/ND should address the cumulative impacts of the project. The Draft IS/ND fails to provide a cumulative analysis regarding GHG emissions.

Responses

The California Natural Resources Agency issued the *Final Statement of Reasons or Regulatory Action* in December 2009. The document includes "Amendments to the State CEQA Guidelines Addressing Analysis and Mitigation of Greenhouse Gas Emissions Pursuant to SB97." The evaluation of GHG impacts is considered by definition a cumulative impacts analysis as stated by the California Natural Resources Agency:

> "Due to the global nature of GHG emissions and their potential effects, GHG emissions will typically be addressed in a cumulative impacts analysis. (See, e.g., EPA, Draft Endangerment Finding, 74 Fed. Reg. 18886, 18904 (April 24, 2009) (—cumulative emissions are responsible for the cumulative change in the stock of concentrations in the atmosphere); California Air Pollution Control Officers Association, CEQA and Climate Change: Evaluating and Addressing Greenhouse Gas Emissions from Projects Subject to the California Environmental Quality Act (January 2008) (—CAPCOA White Paper‖), at p. 35 (—GHG impacts are exclusively cumulative impacts; there are no noncumulative GHG emission impacts from a climate change perspective).) Existing section 15064(h) governs the analysis of cumulative effects in an initial study" (p 17).

The analysis presented in the IS/ND is a cumulative analysis since it is a GHG analysis. Since the project would result in a net decrease in GHG emissions, it would have no cumulatively significant impacts.

2.3.5 SUPPORTING DOCUMENTATION

Comments

Several comments were made regarding the CEQA review period and public access to supporting documentation during that review period:

1. The CPUC failed to provide the public with access to all referenced documents for the entirety of the 30-day public comment period, and therefore violated CEQA.
2. The Draft IS/ND fails to include all assumptions that were used to calculate emissions, and should have included the EPA Clean Air Markets data used for estimating plant-wide emissions between 2000 and 2009. A revised document that includes all of the relevant underlying data must be prepared for public review and comment.

Responses

1. Environmental documents often require the preparation of technical reports or other special documents or studies that relate directly to a proposed project and might not be readily available to the public; such technical reports are typically included as attachments or appendices to the environmental document to ensure ready public access to this source material. The three appendices included in the Four Corners Generation Station Project Draft IS/ND are examples of such source material.

   The purpose of a references section is to provide the reader with the necessary tools to access and review the sources of information that were used in the environmental document. These information sources are typically those that were not created solely for the purposes of the proposed project, that were created by sources other than the Lead

Agency, and that are readily available public documents. The references section of the Four Corners Generation Station Project Draft IS/ND contains six references. Three of these references are for accessible websites, and the other three references are for documents that originated from sources other than the CPUC. All six references are for websites and documents that are available to the public through the internet. The citation provided in the IS/ND provided adequate information for the public to locate the reference cited, and therefore, does not constitute a violation of CEQA.

2. The raw data for the calculations of quantitative impacts were presented in Appendix C of the Draft IS/ND. Assumptions used in the calculations were presented in the Appendix, including the definition of the baseline condition for the calculation, the emissions factors, the units and output considered in the calculations, etc.

   The Clean Air Markets Quick Reports data is referenced in Appendix B. The data from the reports can be found on the EPA website; however, all of the relevant data from the report is presented in the tables in the Appendix, which was available for the entirety of the comment period.

2.3.6 NEPA REVIEW

Comments

Nothing in the record currently indicates that the proposed Four Corners project will be subject to NEPA. Performance of NEPA review is a precondition for a project analysis to avoid any discussion or analysis of out of state impacts where the project is located out of state. As a result, under CEQA Guideline 15277, impacts of local air pollutions and water usage should be considered in the final analysis.

Responses

Public Resources Code Section 21080(b)(14), expressly provides that CEQA does not apply to any project that is located outside of California and that is subject to NEPA, or another state's equivalent law. This is a statutory exemption, and not a categorical exemption; and therefore, any GHG emissions that could have a significant effect on the environment in California are still subject to CEQA review. Nonetheless, the continued operation of the Four Corners facility will be subject to NEPA due to the need to extend the plant's site license, which requires approval by the Bureau of Indian Affairs (BIA), which triggers NEPA.

2.3.7 PREPARATION OF AN EIR

Comment

The project requires preparation of an EIR due to the project's significant, unavoidable GHG emission impacts.

Response

GHG emissions would decrease as a result of the project. The project would have no significant, unavoidable impacts under CEQA, and therefore an EIR is not required.

2.4 INDIVIDUAL RESPONSES TO COMMENTS

2.4.1 LIST OF COMMENTERS

This section presents responses to all of the comments received on the Draft IS/ND during the review period. Each comment letter received is recorded according to the numbering system indicated in the table below.

Identification	Commenter	Affiliation	Date Received
A	Suma Peesapati	Earthjustice (on behalf of Sierra Club)	November 3, 2011
B	Dr. Petra Pless	Pless Environmental Consulting	November 3, 2011
C	Pamela Campos	Environmental Defense Fund	November 3, 2011
D	Ryan Stevenson	Southern California Edison	November 3, 2011

Each comment in each letter received was assigned an alpha- numeric identifier (A-1, A-2, etc.). Responses are provided to each written comment. Where a response is provided in a Master Response or other prior response, the reader is referred to that response. The comment letters are attached to this memorandum in Attachment A.

This section presents the comments received and responses to comments on environmental issues raised regarding the environmental effects of the proposed project. Responses are generally not provided to comments that state opinions about the overall merit of the project or comments about the project description, unless a specific environmental issue is raised within the context of the specific comment. Commenters' opinions are noted. Changes to the Draft IS/ND, where deemed appropriate and necessary to clarify and further enhance the adequacy and readability of the analysis, have been made in the revised IS/ND in strikethrough/underline format.

2.4.2 COMMENTS AND RESPONSES

A Ms. Suma Peesapati
Staff Attorney, Earth Justice
426 17th Street, 5th Floor
Oakland, CA 94612

A-1: The comment is noted. See Master Response 2.3.7 Preparation of an EIR.

A-2: The comment is noted regarding emissions from the existing operation of the Four Corners facility. Please refer to Master Response 2.3.2, under response 2 for an explanation as to why the modifications are not considered in the IS/ND. The modifications are exempted because they would not result in the increase in GHG emissions.

A-3: The comment is noted and Dr. Pless' comments have been considered.

A-4: The comment is noted. Note that the comment period ended on November 3rd. Pursuant to Public Resources Code §21091, the lead agency is not obligated to respond to comments received after the close of the comment period.

A-5: The comment is noted regarding the intent of CEQA.

A-6: See Master Response 2.3.7 Preparation of an EIR. Since implementation of the project would not increase GHG emissions, impacts would be less than significant and an EIR is not required.

Public Resources Code Section 21080(b)(14), expressly provides that CEQA does not apply to any project that is located outside of California and that is subject to NEPA, or another state's equivalent law. This is a statutory exemption, which does not require the consideration of environmental impacts, unlike a categorical exemption. The commenter has confused statutory and categorical exemptions. However, under our methodology, only the components of the project that could have an impact in California (the emissions of GHG) are considered for analysis, as required by CEQA.

A-7: The entire CEQA document was provided for the 30-day public review period and no pages were missing for any period of time, per the commenter's citation. See Master Response 2.3.5 Supporting Documentation, response 1.

A-8: The tables presented in Appendix B were presented in a format that is understandable to the public, clearly identifying terminology used in the IS/ND text, including the reporting year, the emissions rates, and the permitted emissions rates for the Four Corners Generating Station facility. The appendices are a part of the "single report." All supporting data for the conclusions presented in the IS/ND were provided with the document (namely, Appendix B). References cited related to the discussion of the environmental setting, and were summarized in the text of the IS/ND. See Master Response 2.3.5 Supporting Documentation, response 1.

A-9: See Master Response 2.3.5 Supporting Documentation, response 2. Substantial evidence supporting the conclusions of the document was provided in the IS/ND, for the entirety of the comment period.

A-10: The CPUC finds that the project description, as presented in the IS/ND, is complete and accurate, in accordance with the requirements of CEQA.

A-11: See Master Response 2.3.2, response 1.

A-12: See Master Response 2.3.2, response 1.

A-13: See Master Response 2.3.2, responses 1 and 2. Capacity increases could result from improvements due to the availability of more efficient technologies. However, these technologies allow for greater efficiency without increases in fuel consumption or GHG emissions.

A-14: See Master Response 2.3.2, responses 1 and 2. Customer demand is entirely relevant to the operation of the facility. Since the project would not result in the increase of demand, considering existing demand in the development of the likely scenarios is appropriate, regardless of ownership of Units 4 and 5.

A-15: See Master Response 2.3.2, response 2. The modifications would not have local effects in California, and therefore, are not subject to CEQA review.

A-16: The comment is noted. Public Resources Code Section 21080(b)(14), expressly provides that CEQA does not apply to any project that is located outside of California and that is subject to NEPA, or another state's equivalent law. Only GHGs were considered subject to CEQA since GHGs can have an impact on California.

A-17: See Master Response 2.3.2, response 3.

A-18: Substantial argument does not support a case that significant impacts could occur for this project. In a worst case scenario, the Four Corners facility would operate in the same manner as it currently operates, and therefore no increases in GHGs over existing conditions would occur (there would be a net decrease since replacement energy by SCE would have lesser GHG emissions than facilities run by APS). More likely, Units 1-3 would be shut down and a decrease in GHGs would result from the sale of SCE's interest in the plant, having a positive impact on the environment. Refer to responses to Dr. Pless' letter for a discussion of her analysis to this project. The quantification of emissions in the analysis is not a matter of opinion for this project. See also Master Response 2.3.2, response 1.

A-19: Refer to Master Response 2.3.3. Quantitative thresholds can be set for this project; however, the setting of thresholds is not required and would not change the outcome of the analysis, because the GHG emissions would be less than the baseline condition.

A-20 through A-24: See Master Response 2.3.2, response 2. The improvements would not increase fuel consumption, and while increases in efficiency could be realized, no increases in GHG emissions would occur, as provided in testimony by SCE. The arguments presented between experts are not a matter of opinion but a matter of accurate interpretation of facts.

A-25: See Master Response 2.3.4, Cumulative Analysis.

A-26: See Master Response 2.3.2, response 2.

A-27: The comment is noted. See Master Response 2.3.7. Since the project would not result in an increase in GHG emissions, no significant impacts would occur and an ND is the appropriate level of documentation pursuant to CEQA for this project.

B Dr. Petra Pless
Pless Environmental Consulting
440 Nova Albion Way, Suite #2
San Rafael, CA 94903

B-1: The comment is noted.

B-2: The comment is noted.

B-3: The summary of the Four Corners facility and ownership is noted.

B-4: The reasons why the portions of the project related to ratemaking and plant modifications are not subject to CEQA are stated on page 2-3 of the Draft IS/ND. Additional modifications to the IS/ND have been made to more clearly state the reasons why CEQA only applies to GHG emissions for the proposed project. Only the portions of the project that could have a physical effect on the environment in California are considered. See Master Response 2.3.2, response 2 for further explanation as to why the proposed modifications would not result in an increase in GHG emissions.

B-5: See Master Response 2.3.2, response 1. APS has stated the relationship between the sale of SCE's stake in Units 4 and 5 and the shutdown of Units 1-3 in both public statements and in a proposal to the EPA; therefore, it is a reasonable component of the proposed project. Even if the units are not shut down, the overall output from the plant would not change since the overall demand for power is not expected to change as a result of the proposed project: natural gas facilities would likely be shut down to match output with demand.

B-6: See Master Response 2.3.2, response 1.

B-7: The summary of the proposed modifications is noted.

B-8: The comment is noted.

B-9: See Master Response 2.3.2, response 2. While the commenter's observations are noted, SCE testimony has demonstrated that the modifications proposed for the facility would not increase the average historical capacity factors on Units 4 and 5, and any increases in efficiency would not increase fuel usage and therefore would not increase GHG emissions.

B-10: See Master Response 2.3.2, response 1. The scenario of increased average historical capacity is unrealistic based on testimony by SCE. In the worst-case scenario, all units at the facility would operate as they currently operate, with a net decrease in GHG emissions

B-11: See Master Response 2.3.3 CEQA Thresholds. Quantitative thresholds can be set for this project; however, the setting of thresholds would not change the outcome of the analysis, because the GHG emissions would be less than the baseline condition.

B-12: The comment is noted. See Master Response 2.3.7. Since the project would not result in an increase in GHG emissions, no significant impacts would occur and an ND is the appropriate level of documentation for this project.

C Pamela Campos
Attorney
Environmental Defense Fund
123 Mission Street
San Francisco, CA 94105

C-1: The comment is noted.

C-2: The comment is noted. See Master Response 2.3.2, response 2.

C-3: The comment is noted. See Master Response 2.3.2, response 2.

C-4: See Master Response 2.3.6, NEPA Review.

D Ryan Stevenson
Regulatory Affairs
Southern California Edison
P.O. Box 800
2244 Walnut Grove Ave
Rosemead, CA 91770

D-1: The comment is noted.

D-2: The comment is noted.

D-3: The comment is noted.

D-4: The comment is noted. Modifications to the IS/ND have been made to more clearly state the reasons why CEQA only applies to GHG emissions for the proposed project.

D-5: The comment is noted. See Master Response 2.3.2, response 2. While it is noted that SCE would replace generation lost at Four Corners with new generation in California that would be cleaner, the overall demand for power is not expected to increase. Net generation by SCE and APS is not expected to change.

D-6: The comment is noted regarding Scenario 2. Scenario 2 has been revised to remove the potential increase in capacity factor to 100%, since it is unreasonable. The use of the increased 103 MWs by APS through the decrease of natural gas generation elsewhere is still reasonable in this scenario. Revision of the scenario results in further decreases in overall GHG emissions.

D-7: The minor changes are noted and have been made in the Final IS/ND.

REFERENCES

References cited in this memorandum are provided below.

California Climate Action Registry (CCAR). 2009. General Reporting Protocol, Version 3.1, Appendix C. January 2009.

California Natural Resources Agency. 2012. http://ceres.ca.gov/ceqa/docs/Final_Statement_of_Reasons.pdf. Final Statement of Reasons or Regulatory Action. California Natural Resources Agency. Accessed January 14, 2012.

California Public Utilities Commission (CPUC). 2007. Decision No. 07-01-039, page 8, SB 1368 Emission Performance Standards.

POWERnews. 2012. http://www.powermag.com/POWERnews/APS-to-Buy-SCEs-Stake-in-Four-Corners-and-Shutter-27-percent-of-Plants-Capacity_3156.html. Power, Business and Technology for the Global Generation Industry. Accessed January 14, 2012.

SCAQMD (South Coast Air Quality Management District). 2008. *Interim CEQA Greenhouse Gas Significance Threshold*, Oct. 2008.

ATTACHMENT A: COMMENT LETTERS

VIA ELECTRONIC MAIL

November 3, 2011

Andrew Barnsdale, CPUC Project Manager
California Public Utilities Commission
505 Van Ness Ave., 4th Floor
San Francisco, CA 94102
Email: FourCorners@rmtinc.com

Re: Draft Initial Study/Negative Declaration for the Four Corners Generating Station Project

Dear Mr. Barnsdale:

I. INTRODUCTION

I am writing on behalf of the Sierra Club with regard the California Public Utilities Commission's ("CPUC") review of Southern California Edison's ("SCE") proposed sale of its share of the Four Corners Power Plant ("Four Corners"). As explained more fully below, approval of the Project without preparation of an environmental impact report ("EIR") required by the California Environmental Quality Act ("CEQA") is a violation of state law. The CPUC may not approve the Project until an adequate EIR is prepared and circulated for public review and comment. A-1

The Project includes major modifications to Four Corners that collectively constitute a massive life-extending and capacity-increasing program. These modifications will significantly increase the potential greenhouse gas emissions from one of the largest sources of pollution in the entire country. According to the EPA's Clean Air Markets database, last year, Four Corners emitted over 38,000 tons of nitrogen oxide ("NOx") pollution, over 11,000 tons of sulfur dioxide pollution ("SO2"), and over 14 million tons of carbon dioxide ("CO2"). The plant also emits significant amounts of particulate matter ("PM") and mercury, a neurotoxin.

The CPUC has, without any explanation, exempted these modifications from its CEQA review. Sierra Club and its members are concerned that by exempting the Project from CEQA, the Draft Initial Study/Negative Declaration ("IS/ND") fails to evaluate the potential impacts of the Project, inform the public about the potential impacts of the Project, and mitigate these impacts. Full disclosure and mitigation of the Project's greenhouse gas ("GHG") emissions is particularly important in this case where the sale is being motivated by SCE's claimed compliance with California's GHG requirements. Because these state requirements contemplate A-2 an overall reduction of California's contribution to climate change, the CPUC should not allow any potential unmitigated increase in GHGs as part of this sale proceeding. A-2

Accompanying this letter are expert comments by Dr. Petra Pless, which provide extensive analysis of the significant environmental impact that will result from this Project's contribution to climate change . Dr. Pless is an exceptionally well-qualified expert with many years of experience in studying power plants and with special expertise in power plant compliance with California environmental law. Dr. Pless holds a doctorate in Environmental Science and Engineering ("D. Env.") from the University of California Los Angeles and has professional experience in the areas of air quality and global climate change. Dr. Pless provides substantial evidence of a fair argument that an EIR must be prepared for this Project. Dr. Pless's comments, which require a separate response from the agency, are hereby incorporated in these legal comments. A-3

We reserve the right to supplement these comments at any time. We incorporate by reference all comments that have been or will be submitted by any other entities, agencies, organizations or individuals concerning the Project. A-4

II. THE IS/ND DOES NOT COMPLY WITH CEQA

A. CEQA REQUIRES THE FULLEST PROTECTION OF THE ENVIRONMENT

CEQA requires public agencies to consider and document the environmental implications of their actions in order to "[e]nsure that long term protection of the environment…shall be the guiding criterion in public decisions."[1] In enacting CEQA, the Legislature declared it to be the policy of California to "take all action necessary to provide the people of this state with clean air and water."[2] CEQA requires all agencies to give major consideration to preventing environmental damage while providing a decent home and satisfying living environment for every Californian. [3]

The environmental review process created by CEQA carries out this mandate by bringing citizens' environmental concerns about a proposed project to the attention of public agencies. CEQA requires public agencies to determine whether a project may have a significant impact on the environment.[4] The courts have explained that preparation of an environmental impact report ("EIR") is "intended to furnish both the road map and the environmental price tag for a project, so that the decisionmaker and the public both know, before the journey begins, just where the journey will lead, and how much they--and the environment--will have to give up in order to take that journey."[5] A-5

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[1] CEQA Guidelines § 21001 (d).

[2] CEQA Guidelines § 21001(b); Sierra Club v. State Bd. of Forestry (1994) 7 Cal.App.4th 1215.

[3] CEQA Guidelines § 21000 (g).

[4] CEQA Guidelines § 21151.

[5] *Natural Resources Defense Council, Inc. v. City of Los Angeles* (2002) 103 Cal.App.4th 268, 271.

The California Supreme Court has declared that CEQA must be interpreted "to afford the fullest possible protection to the environment within the reasonable scope of the statutory language."[6] "When the informational requirements of CEQA are not complied with," or if the agency's action actions preclude informed decisionmaking and public participation, the goals of CEQA are thwarted and a prejudicial abuse of discretion has occurred."[7] A-5

In this case, there is substantial evidence that the sale may increase the amount of pollution, including greenhouse gases, that Four Corners is capable of emitting. Thus, the CPUC would abuse its discretion by failing to adhere to CEQA requirements, which require preparing an EIR and subjecting the Project to a full and public review process. Exempting the Project from CEQA violates the spirit and letter of CEQA. "Where there is a reasonable possibility that a project or activity may have a significant effect on the environment, an exemption is improper."[8] A-6

Below, we explain that the sale of Four Corners, andthe capital investments connected to the sale, are not eligible for any CEQA exemption. Additionally, we provide substantial evidence of a fair argument that the Project must be reviewed and mitigated through an EIR because the Project will have significant adverse environmental impacts from operational air pollution and cumulative air pollution.

B. THE CPUC FAILED TO HAVE ALL SUPPORTING DOCUMENTS ACCESSIBLE TO THE PUBLIC DURING THE ENTIRE COMMENT PERIOD

1. The DEIR Failed to Provide the Public with Access to All Referenced Documents During the Entire Comment Period.

Page 4-1 of the IS/ND is entitled "References." Despite Earthjustice's multiple written and verbal requests to view these referenced materials, the agency did not make them available A-7 to us until Wednesday October 26, 2011, the day before the original comment deadline for the Project. See attached letters dated September 30, 2011 and October 20, 2008 and emails dated October 26, 2011 and November 1, 2011(collectively attached as "Exhibit A"). Although we requested a 30-day extension of the comment period from the date the CPUC provided the referenced materials, the agency denied our request and instead offered only one additional week to comment. The agency's failure to extend the comment period to allow a full 30 days after first providing access to these references violated CEQA. More specifically, CEQA section 21092(b)(1) requires that the CEQA notice of availability include "the address where copies of

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[6] *Communities for a Better Environment v. Calif. Resources Agency* ("CBE v. CRA") 103 Cal.App.4th 98, 110 (2002); *see also Pocket Protectors v. City of Sacramento* (2004) 124 Cal. App. 4th 903, 926.

[7] *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1220 (internal citations omitted).

[8] *International Longshoremen's & Warehousemen's Union v. Board of Supervisors* (1981) 116 Cal.App.3d 265, 276.

the proposed [CEQA document] and all documents referenced therein are available for review and readily accessible during the agency's normal working hours." Remy, Thomas and Moose, *Guide to the California Environmental Quality Act*, p. 300 (Solano Press Books, 2007). As further noted by leading CEQA commentators, Remy and Thomas:

> The above-referenced section [21092(b)(1)] requires the agency to notify the public of the address at which "all documents referenced in a [CEQA document]" can be found (and presumably read) . . . seems to require agencies to make available for public review all documents on which agency staff or consultants expressly rely in preparing a [CEQA document]. In light of case law emphasizing the importance of ensuring that the public can obtain and review documents on which agencies rely for the environmental conclusions (*see, e.g., Emmington v. Solano County Redevel. Agency*, 195 Cal.App.3d 491, 502-503 (1987)), agencies should ensure that they comply literally with this requirement.

A-7

(*Id*., parenthetical note in original.) The courts have held that the failure to provide even a few pages of a CEQA document for a portion of the CEQA review period invalidates the entire CEQA process. *Ultramar v. South Coast Air Quality Man. Dist*., 17 Cal.App.4th 689 (1993). The agency's failure to make the references accessible to the public during the entire public comment period violated CEQA. CEQA § 21157.1(c) and 21092(b)(1).

2. The IS/ND Fails to Include All Assumptions Used to Calculate Emissions

Appendix B to the IS/ND is entitled "Four Corners Plantwide Emissions Summary." This appendix is the sole evidentiary support for the IS/ND's analysis of GHG emissions impacts. This appendix does not contain the EPA Clean Air Markets data used for estimating plantwide emissions between 2000 and 2009.

The IS/ND's failure to incorporate of the relevant information in the the document in a manner that is understandable to the public violates CEQA's disclosure requirements. The CEQA document must be "a compilation of all relevant data into a single formal report . . . which would facilitate both public input and the decisionmaking process." (*Russian Hill Improvement Association v. Board of Permit Appeals*, (1975) 44 Cal.App.3d 158, 168.)

A-8

As evidenced by our September 30th Public Records Act ("PRA") request (included in Exhibit A), we requested all documents related to the IS/ND. These requests clearly included supporting data for the IS/ND, which is critical to an informed review of the IS/ND. Without such data, the CPUC violates CEQA by failing to provide substantial evidence to support its environmental conclusions. (*Sierra Club v. Contra Costa County*, (1992) 10 Cal.App.4th 1212, 1222 1224.) A revised document that includes all of the relevant underlying data must be prepared for public review and comment.

3. The Agency's Entire CEQA Analysis from "Start to Finish" Is Subject to Public Scrutiny

As discussed above, the IS/ND does not include the raw data and evidence used to arrive at its quantitative impact estimates. It further fails to provide any evidence supporting its claim that the physical modifications to the plant are exempt from review. Although we requested immediate access to all information related to the Project through a September 30th PRA request, the agency failed to provide the responsive documents until over a month later, on November 1st 2011, which was two days before the extended comment deadline for the Project. *See* Exhibit A. The agency's tardy and incomplete response to our PRA request not only violated the PRA, but also substantially impaired Sierra Club's ability to make fully informed comments on the Project.

Due to these major evidentiary gaps in the document and the underlying record, it is impossible for the public, and the agency's decisionmakers, to make an informed assessment of whether the IS/ND's impact estimates are correct and legitimate. This violates CEQA. "Conclusory comments in support of environmental conclusions are generally inappropriate…" (*Laurel Heights Improvement Assn. v. Regents of University of California*, (1988) 47 Cal.3d 376, 404.) That court went on to explain that "there must be a disclosure of the "analytic route the… agency traveled from evidence to action." (*Id*.) A revised CEQA document must include all the underlying data supporting its environmental conclusions. The numerical estimates contained in the IS/ND that led to its proposed findings of no significant impact must be based on evidence. The very basic legal question at play in this case is whether the IS/ND's findings are supported by "substantial evidence." A-9

Findings must be made for each identified impact, and must be supported by substantial evidence in the record. (*Sierra Club v. Contra Costa County*, (1992) 10 Cal.App.4th 1212, 1222 1224.) Findings must present some explanation to supply the logical step between the ultimate finding and the facts in the record. (*Topanga Assn. for a Scenic Community v. County of Los Angeles*, (1974) 11 Cal.3d 506, 515.) Conclusory statements are inadequate. (*Village Laguna of Laguna Beach, Inc. v. Board of Supervisors,* (1982) 134 Cal.App.3d 1022, 1034-1035.) Finally, detailed findings force decisionmakers to draw legally relevant sub-conclusions that support their ultimate decisions. In so doing, the agency minimizes the likelihood that it will randomly leap from evidence to conclusions. (*Sacramento Old City Assn. v. City Council of Sacramento*, (1991) 229 Cal.App.3d 1011, 1034.).

C. THE IS/ND LACKS AN ADEQUATE PROJECT DESCRIPTION

An accurate, stable and finite project description is the *sine qua non* of an informative and legally adequate CEQA document. (*County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 192 [139 Cal.Rptr. 396, 401].) Without it, CEQA's objective of fostering public disclosure and informed environmental decisionmaking is stymied. As one analyst has noted: A-10

> The adequacy of a [CEQA document's] project description is closely linked to the adequacy of the [CEQA document's] analysis of the project's environmental effects. If the description is inadequate because it fails to discuss the complete project, the environmental analysis will probably reflect the same mistake.

(Kostka and Zischke, "Practice Under the California Environmental Quality Act," p. 474 (8/99 update).) A-10

Here, the Project description is incomplete and inaccurate. As explained below, the "Scenarios" cited by the IS/ND are inaccurate, incomplete and misleading. Furthermore, the IS/ND fails to disclose and analyze the impacts of a number of essential elements of the Project including proposed modifications to the plant beginning in 2007 and lasting until 2014, and SCE's relinquishment of its transmission capacity.

1. The IS/ND's "Scenarios" Are Inaccurate and Misleading

Instead of describing the "whole of the Project," the IS/ND presents three separate "scenarios" that have no basis in law or fact. CEQA requires an analysis of all significant and potentially significant impacts associated with the Project as a whole. By presenting three fundamentally flawed scenarios, then choosing two that artificially show a decrease in emissions, the IS/ND expressly seeks to avoid analysis of the of the full range of potential impacts required by CEQA. A-11

a. Scenario 1 Represents Nothing More than Speculation and Ignores Temporary Increases in GHGs

In "Scenario 1," the CPUC relies on a November 24, 2010 settlement offer that APS sent to EPA proposing, among other things, shutdown of Units 1-3 for the purpose of resolving its Clean Air Act liability. IS/ND at p.2-5. This letter is nothing more than pure speculation and does not represent any enforceable commitment to retire those three units. CPUC's reliance on this letter to define the "project" for purposes of CEQA is therefore illegal. Furthermore, the IS/ND's suggestion that shutdown of Units 1-3 is inherently connected to the sale lacks an evidentiary basis. In fact, based on the "uncertainties" described on page 3 of Appendix A to the IS/ND, any potential future shutdown of these units may be the result of their poor economic viability due to upcoming federal environmental regulatory action, which is entirely unrelated to the physical capacity of these units or to the sale of SCE's share of the power plant. See Exhibit 2 to Exhibit I at p.4. Finally, even if APS's November 24, 2010 proposal eventually materializes, Units 1-3 will not retire until 2014, thereby allowing the facility to operate all five units at full capacity for many months after the sale but before shutdown. Temporary impacts are not exempt from CEQA. In short, Scenario 1 does not provide a legal project description. A-12

b. Scenario 2 Ignores the Capacity and Reliability-Increasing Effects of SCE's Modifications

"Scenario 2," which is nothing more than a slight modification of "Scenario 1," contemplates shutdown of Units 1-3 and increased output from Units 4-5. IS/ND at p. 2-5. As explained above, any project description that assumes shutdown of Units 1-3 lacks evidentiary support and is contrary to law. Second, the "increased output" from Units 4-5 fails to account for the reliability and capacity increases resulting from SCE's past, current and future capital investments in the facility. For these reasons, Scenario 2 represents a similarly deficient project description. A-13

c. Scenario 3 Improperly Ignores the GHG-Increasing Effects of SCE's Capital Investments

"Scenario 3," which comes the closest to offering a legal project description of the three scenarios, is also defective because it fails to consider the increased capacity and availability of Units 4 and 5 resulting from SCE's capital investments. IS/ND at p.2-5 to 2-6. Nonetheless, after proposing this scenario, the IS/ND then rejects it from further consideration under the flawed logic that "APS has already stated its intention to close Units 1-3 at some future date" and that "the energy production that would result under this scenario far exceeds the demands of APS's customers." *Id*. As explained above, any retirement of Units 1-3 is pure speculation and would still allow for interim increases in pollution. The second part of the IS/ND's explanation, which is related to customer demand, misses the entire point of CEQA review, which is to disclose, analyze and mitigate all *potential* environmental impacts based on fact and reasonable forseeability, rather than make baseless assumptions that seek to avoid a finding of significant impact. As explained by the Supreme Court, the concept of significant impact should not be used "as a subterfuge to excuse the making of impact reports otherwise required by the act." (*Friends of Mammoth v. Board of Supervisors of Mono County,* (1972) 8 Cal. 3d 247, 271). Customer demand is entirely irrelevant to the capacity and potential emissions of the plant. Furthermore, even under the sale, APS would not be the only owner of Units 4 and 5, making this statement entirely irrelevant to this CEQA review. A-14

2. Proposed Approval of the Sale and Proposed Capital Investments Are Subject to CEQA Review

a. SCE's Capital Expenditures Are Subject to CEQA

"Project" within the meaning of CEQA is defined as any activity that may cause a direct or reasonably foreseeable indirect physical change to the environment, including activities involving the issuance to a person of a lease, permit, license, certificate or other entitlement for use by one or more public agencies.[9] The term "project" refers to the whole of an action and to A-15

[9] Pub. Res. Code § 21065; CEQA Guidelines § 15378.

the underlying activity being approved.[10] By defining "project" broadly, CEQA ensures that the action reviewed is not just the approval itself, but also the activity resulting from the approval.[11]

The sale of Four Corners and ***all activity associated with this sale*** are a "project" under CEQA. Beginning in 2007, SCE began making significant modifications to the power plant to prepare the plant for sale. These modifications increase its potential environmental impacts, including increased air pollution.[12] While there is no distinction between SCE's pre-2012 investments and the later investments the for the purpose of defining a "project" under CEQA, the CPUC has created an artificial and illegal distinction between these two categories simply because the sale proceeding does not involve approval of the earlier investments. In fact, the IS/ND fails to even mention the 2007-2011 capital investments that SCE made for the express purpose of preparing the plant for sale. There is no question that these earlier modifications are also part of the sale. In fact, both SCE and the CPUC have acknowledged this fact. In the proceeding establishing an Emissions Performance Standard for the Four Corners Power Plant, the CPUC stated that "[w]hile SCE stresses the link to reliability, it concedes that some capital expenditures may have ***dual purposes*** – not only maintenance, but ensuring that 'Four Corners retains some residual value' should SCE subsequently divest its interest." CPUC Rulemaking 06-04-009, filed on April 13, 2006 at p.15 (emphasis added) (Attached as Exhibit C). SCE reiterated this point in its 2012 General Rate Case application, where it states, A-15

> [T]he fact that these expenditures may have helped facilitate the proposed sale of SCE's plant share does not mean that if the expenditures had not been made, that the plant would be (or would have been) retired on or before the current termination of the co-ownership agreements. The other owners have consistently expressed their desire to continue to operate the plant up until or beyond the existing co-ownership term. SCE does not believe that our participation in the capital expenditures made and forecast for 2007-2011 has had (or will have) a material impact on the ultimate retirement date of Units 4 & 5.

CPUC Proceeding A.10-11-015, SCE Exhibit No. SCE-02, Vol. 6, Part 3, p. 24 – 25 (attached as Exhibit D). Thus, according to SCE, these investments would have occurred with or without its participation and that the only real objective of SCE's participation was to facilitate the sale. *Id*. In other words, both SCE and the CPUC acknowledge that SCE's only objective in participating in these past and current investments was/is to facilitate the sale. SCE's investments are therefore indisputably part of the "project" under CEQA.

With respect to SCE's post-2011 investments, these, too, form part of the project. Although the IS/ND acknowledges that SCE is seeking approval[13] of these modifications in this

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[10] CEQA Guidelines § 15378(a), (c)-(d); *Association for a Cleaner Env't v. Yosemite Community College Dist.* (2004) 116 Cal.App.4th 629, 637.

[11] CEQA Guidelines § 15378.

[12] A list of those modifications, including SCE's updated testimony, is appended here as Exhibit B.

[13] Any such approval would be, without question, a discretionary action.

sale proceeding, the document inexplicably states that "the CPUC has determined that [the post-2011 capital expenditures] are not subject to CEQA review." IS/ND at p. 2-3. Aside from lacking any logical basis, this bare conclusion is contrary to law.

An activity may be excluded from CEQA review in only two circumstances: 1) when the CEQA statute or Guidelines specially provide for a categorical exemption or 2) when specific exemptions have been created by the legislature. The IS/ND does not claim either type of exemption. Because, in violation of CEQA, the document provides no explanation of this issue, the public is forced to simply guess the analytical basis for this conclusion. This defect must be cured in a revised document that provides the legal and factual basis for the claimed exemption.

One conceivable basis for this conclusion is the statutory exemption contained in CEQA §21080(b)(8). Should this be the case, the CPUC misplaces its reliance on this CEQA provision. That provision applies to "[t]he establishment, modification, structuring, restructuring, or approval of rates, tolls, fares, or other charges by public agencies . . ." *Id*. As explained by SCE itself, it is not seeking to establish, modify, structure, restructure or gain approval of rates in this proceeding. To the contrary, the company expressly states that it:

> …disagrees with Sierra Club's assertion that these forecast 2012 expenditures must be found "reasonable" in this proceeding ***as if it were a base rate case application. In this proceeding, SCE only seeks Commission approval of these 2012 expenditures as part of overall approval of the proposed sale.*** If the sale is not approved, or is not successfully completed for any other reason, then the reasonableness of these expenditures will be determined in SCE's 2012 GRC proceeding. A-15

Proceeding No. A 10-11-010, Exhibit SCE -02 (SCE May 19, 2011 Rebuttal Testimony, attached as Exhibit E), p.12:lines 17-21 (emphasis added). Thus, as explained by the company itself, in this proceeding, the only purpose of the proposed 2012 investments is to support the sale of the power plant. SCE is therefore ineligible for any CEQA exemption. The IS/ND must be revised to cure this defect and a new CEQA document must be recirculated for public review and comment.

The earlier (pre-2012) investments similarly fall outside the above exemption in this proceeding because, as discussed above, they were made to support the sale. The fact that those investments are also being reviewed in SCE's General Rate Case has no relevance to the CEQA review in this sale proceeding. As explained above, the term "project" refers to the whole of an action and to the underlying activity being approved. While CPUC approval of a change in rates might be exempt from CEQA, the underlying modifications are not.

Furthermore, before it may claim such an exemption, CEQA requires the agency to "incorporate written findings in the record of any proceeding in which an exemption under this paragraph is claimed setting forth with specificity the basis for the claim of exemption." CEQA

§21080(b)(8). The IS/ND provides no such findings. The document is defective for this additional reason. Should the document be revised to include these findings, it must be recirculated for public comment. A-15

b. The CPUC Cannot Exempt Itself from CEQA

As explained above, the exclusive categories of exemptions under CEQA are statutory exemptions created by the Legislature and categorical exemptions created by the Resources Agency. The CPUC has no authority to create its own exemption that is separate from these two categories. In other words, the mere fact that the agency has given "ratemaking treatment" to SCE's capital investments in this proceeding does not create a new CEQA exemption. Any rate-based exemption only comes into play when the agency action actually affects rates in the manner contemplated by CEQA §21080(b)(8). A-16

c. The IS/ND Illegally Ignores the Environmental Impacts Associated with SCE's Relinquishment of its Transmission Rights

In its application, SCE states that as part of the overall sale of its interest in Four Corners, it "has agreed to terminate its interest in a Transmission Service Agreement on a transmission line owned by [its co-owner], which transmits electricity from Four Corners to SCE's transmission system." Application No. 10-11-010 (filed November 15, 2010) at p.3: fn.4 (attached as Exhibit F). The IS/ND fails to even mention this aspect of the Project, let alone analyze its potential environmental impacts. It is possible that SCE's termination of its transmission rights will make the delivery of renewable energy more difficult and expensive, which incentivizes additional fossil fuel-based energy generation and transmission. The environmental impacts of this transmission piece of the Project must be fully disclosed and analyzed in a revised and recirculated CEQA document. A-17

D. THE PROJECT'S SIGNIFICANT ADVERSE IMPACTS TRIGGER CEQA's EIR REQUIREMENT

A negative declaration is improper, and an EIR is required, whenever substantial evidence in the record supports a "fair argument" that significant impacts may occur. Even if other substantial evidence supports the opposite conclusion, the agency nevertheless must prepare an EIR. (*Arviv Enterprises v. South Valley Area Planning Comm.* (2002) 101 Cal.app.4th 1333, 1346; *Stanislaus Audubon v. County of Stanislaus* (1995) 33 Cal.App.4th 144, 150-151; *Quail Botanical Gardens v. City of Encinitas* (1994) 29 Cal.App.4th 1597.) The "fair argument" standard is an exceptionally "low threshold" favoring environmental review in an EIR rather than a negative declaration, which terminates the environmental review. (*Pocket Protectors v. City of Sacramento* (2004) 124 Cal.App.4th 903, 928.) The "fair argument" standard requires preparation of an EIR if any substantial evidence in the record indicates that a project may have an adverse environmental effect. (CEQA Guidelines § 15064(f)(1); *Pocket Protectors v. City of Sacramento,* A-18 *supra*, 124 Cal.App.4th at 931.) Under the "fair argument," CEQA always resolves the benefit of the doubt in favor of the public and the environment.

As a matter of law, "substantial evidence includes … expert opinion." (Pub. Resources Code § 21080(e)(1); CEQA Guidelines § 15064(f)(5).) As a leading CEQA treatise explains: "when experts disagree over the significance of an impact, the lead agency must treat the effect as significant and prepare an EIR." (Kostka & Zischke, Practice Under the California Environmental Quality Act, § 6.51, citing CEQA Guidelines § 15064(g), see also, §15064(f)(5).) In fact, courts have held that even lay opinion unsupported by expert evidence is often sufficient to support a "fair argument" requiring an EIR. (*Mejia v. Los Angeles*, 130 Cal. App. 4th 322, 339 (2005)) ("Project opponents who challenge a negative declaration often have no expert studies to rely on. Recognizing this, courts have held that the absence of expert studies is not an obstacle because personal observations concerning nontechnical matters may constitute substantial evidence under CEQA.")

As discussed below, there is much more than a fair argument that the Project will significantly increase greenhouse gas emissions from the Four Corners Power Plant. CEQA requires that these impacts be analyzed in an EIR to inform the public and public decisionmakers of the potential impacts, to consider alternatives to the Project, and to consider mitigation measures to reduce these and other harmful impacts. (*See*, *Security Environmental Systems v. South Coast Air Quality Management District* ("Security Environmental Systems v. SCAQMD") (1991) 229 Cal. App. 3d 110.) As a result of these potentially significant adverse impacts on climate change, the IS/ND is legally and factually untenable. The courts have required EIR's even for residential developments of 21 homes, *see, Arviv Enterprises v. South Valley Area Pln. Comm*., (2002) 101 Cal. App. 4th 1333; *Mejia v. Los Angeles, supra*, and for 40-home residential developments whose only impact was blocking the view from a park. (*Quail Botanical Gardens v. City of Encinitas* (1994) 29 Cal.App.4th 1597.). A-18

In this case, our expert, Dr. Petra Pless, has conducted detailed analysis and independent investigation and has concluded that the Project, as a whole, will have very significant impacts. More specifically, Dr. Pless found that the capacity and reliability increases associated with the 2007-2014 modifications described above carry the potential to significantly increase emissions. In light of Dr. Pless's expert testimony and based on the CEQA law described above, it is clear that an EIR is required for a sale that is predicated upon a massive retooling of one of the largest power plants (and largest sources of pollution) in the entire country.

1. A Significance Threshold of Zero For GHG Emissions is Appropriate

On the question of determining whether or not the impacts are significant, CEQA urges the use of quantitative or objective thresholds (i.e. emission rates in pounds per day or tons per year). The IS/ND contains no quantitative significance thresholds. Instead of defining "significant" as an emission rate, the document simply states that "impacts to GHGs may be A-19 considered "significant" if the project generates GHG emissions "that may have a significant impact on the environment." IS/ND p.3-3. The CPUC thus takes the nonsensical approach of using "significant impact" to define "significant impact." The document then argues that other governmental agencies, such as CEC and the State of New Mexico have not developed a significance threshold for GHGs. *Id.* This argument is a red herring. CEC's (or any other governmental entity's) failure to develop a significance threshold does not excuse the CPUC (the lead agency, here) from developing its own. CEQA Guidelines § 15064.7 ("Each agency is encouraged to develop and publish thresholds of significance that the agency uses in the determination of the significance of environmental effects"); Pub. Res. Code § 21082 (directing agencies to adopt procedures and criteria for evaluating projects). In fact, the CPUC is required to educate itself on available approaches for evaluating impacts, develop a methodology for evaluating impacts, and disclose all that it reasonably can. *Berkeley Keep Jets Over the Bay Committee v. Board of Commissioners*, (2001) 91 Cal.App.4th 1344, 1370.

Given AB 32 and SB 1368's premise that California must *reduce*, not just maintain, current emissions levels, "[l]ocal governments, which are generally responsible for approving development proposals, could reasonably set thresholds of significance at zero, thus requiring the addition of feasible mitigation measures to create carbon neutral projects." Trisolini, K., NEPA, CEQA, and Climate Change, Environmental Law Reporter, Volume 2007, Issue No. 6 at p.218. A threshold of zero is particularly applicable to this case, where the underlying action (the sale) is being motivated by SB 1368—a legislative mandate to reduce California's contribution to climate change in the context of electricity generation and consumption. SB 1368 prohibits new long-term commitments and investment in power-generating facilities that do not comply with its Emissions Performance Standard ("EPS"). There is no question that the Four Corners Power Plant already fails to comply with the EPS, thereby triggering the current sale. In this regulatory context, any increase in GHGs from modifications associated with the sale should be considered significant under CEQA.

A-19

Furthermore, other agencies have developed quantitative thresholds. The Bay Area Air Quality Management District, for example, has a GHG significance threshold of 10,000 tons per year.[14] The South Coast Air Quality Management District has also published an interim significance threshold of 10,000 metric tons per year for projects that do not capture 90% of their greenhouse gas emissions.[15] As explained below, the Project carries significant GHG impacts based on these thresholds as well.

Finally, with respect to the second "threshold" contained in the IS/ND, namely, whether the project "[c]onflict[s] with an applicable plan, policy or regulation adopted for the purposes of reducing the emissions of GHGs," as discussed below, because SCE's capital investments do not comply with SB 1368 or the Commission's Emissions Performance Standard, they carry a *per*

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[14] http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/CEQA/Adopted%20Thresholds%20Table_December%202010.ashx?la=en (last visited on November 1, 2011)
[15] http://www.aqmd.gov/hb/2008/December/081231a.htm at Table 1 (last visited on November 1, 2011)

se significant adverse environmental impact, thus triggering CEQA's EIR requirement for this additional reason. IS/ND at p. 3-3. A-19

2. SCE's 2007-2014 Capital Investments Significantly Increase the Capacity and Availability of the Plant, Which Significantly Increases Potential GHG Emissions

As explained by Dr. Pless in her attached comments, it is reasonable to assume that the past, current and future capital investments associated with the sale could allow the facility to reach its full capacity and its full potential to emit. Under this scenario, and using the IS/ND's own analytical framework (which uses 8760 hours per year to quantify the plant's potential to emit), Dr. Pless opines that the Project could increase greenhouse gas emissions by ***6,548,599 tons per year*** above the IS/ND's claimed baseline levels. Such a vast increase in greenhouse gases is not only much more than zero and much more than the 10,000 ton-per-year significance threshold adopted by various California air districts, but is significant by any measure and constitutes much more than a fair argument of significant environmental impact. This alone triggers CEQA's EIR requirement. A-20

3. Increased Reliability from Modifications, as a Whole

In her attached comments, Dr. Pless opines that the combined effect of all of SCE's modifications is to increase reliability. Even a one percent increase in reliability, which is easily achieved by the types of overhauls represented by SCE's capital investments, would result in a 98,903 ton-per-year increase in potential greenhouse gas emissions. This alone constitutes a fair argument of a significant and adverse environmental impact, which triggers CEQA's EIR requirement. A-21

4. Increased Capacity Due to High Pressure Turbine Upgrades

As Sierra Club explained in its briefing in SCE's 2012 General Rate Case, SCE's own testimony shows that its High Pressure Turbine upgrade projects may have increased the capacity of Units 4 and 5 by 1-3%. See, e.g. Sierra Club's October 17, 2011 Reply Brief in Proceeding A. 10-11-015 (attached as Exhibit G) at p.3. According to Dr. Pless's attached comments, even a one percent increase in capacity would allow a 98,903 ton-per-year increase in potential greenhouse gas emissions. This alone constitutes a fair argument of a significant and adverse environmental impact, which triggers CEQA's EIR requirement. A-22

5. Boiler Tube Replacements Alone Significantly Increase Reliability and Potential Greenhouse Gas Emissions

In this sale proceeding, SCE is seeking, among other things, CPUC approval of certain boiler tube replacements that are scheduled for 2014. See e.g., SCE's Rebuttal Testimony (A.10-11-010, Exhibit No. SCE-02), Table III-1, p.15 (attached as Exhibit E). Also see, SCE's July 5, Rebuttal Testimony in A.10-11-015, at p.35, Table IX-3l (Attached as Exhibit H). According to SCE itself, boiler tube deterioration in Units 4 and 5 has caused forced outages that average 679 A-23 hours per year, which represents 4% of the total outage time. *Id*. at pp. 36-37. Eliminating just one of these four percentage points, which, according to Dr. Pless, which will easily result from these tube replacements, especially when combined with all of the other reliability-focused investments in the plant, would cause a 98,903 ton-per-year increase in potential greenhouse gas emissions. This, too, is a significant environmental impact that must be fully disclosed, analyzed and mitigated in an EIR for the Project. A-23

6. The Modifications Do Not Comply with SB 1368 or the Commission's Emissions Performance Standard, thus Triggering CEQA's EIR Requirement

As discussed in Sierra Club's attached briefs, SCE's 2007-2014 capital investments in the plant do not comply with SB 1368 or the CPUC's Emissions Performance Standard. See Exhibits I, J, and G. These arguments in the briefs are hereby incorporated in this comment letter and should be responded to separately. As discussed in those briefs, SCE's approximate $138.475 million capital investment in the Four Corners Power Plant constitutes a massive life-extension and capacity-increasing program. Because these expenditures are not necessary for "basic operation" of the power plant until 2016 (when SCE's contractual commitment to the plant expires), they violate both SB 1368 as well as the Commission's Emissions Performance Standard. The briefs also explain that SCE lacks authority to make any post-2011 investment in the plant. A-24

E. THE PROJECT's CUMULATIVE IMPACTS ARE SIGNIFICANT

CEQA §21083(b) requires a mandatory finding that a project will have a significant effect on the environment if "the possible effects of a project are individually limited but cumulatively considerable . . . 'Cumulatively considerable' means that the incremental effects of an individual project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects." *Id*. "Cumulative impacts" are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts." CEQA Guidelines §15355(a). "Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time." CEQA Guidelines § 15355(b).

A-25

Based on the incorrect and misleading finding that the Project would result in a net decrease in greenhouse gases, IS/ND fails to provide any cumulative impact analysis. IS/ND at p. 3-6. The importance of an adequate cumulative impacts analysis is explained in *Communities for a Better Environment v. California Resources Agency* ("*CBE v. CRA*"), 103 Cal.App.4th 98, 116 (2002), where the court states:

> Cumulative impact analysis is necessary because the full environmental impact of a proposed project cannot be gauged in a vacuum. One of the most important environmental lessons that has been learned is that environmental damage often occurs incrementally from a variety of small sources. These sources appear

insignificant when considered individually, but assume threatening dimensions when considered collectively with other sources with which they interact.

Even if the 2007-2011 capital investments in Four Corners were not part of the "Project" (which they are), in the alternative, they are part of the cumulative scenario, which the IS/ND ignores. As explained by Dr. Pless and described above, these modifications, when viewed in combination with each other, result in significant adverse environmental impacts with respect to climate change. A-25

F. THE IS/ND MAY NOT PIECEMEAL THE PROJECTS TO AVOID THE CUMULATIVE IMPACTS

The IS/ND,must consider all of the above-described 2007-2014 modifications to Four Corners together. Exhibit B. Failure to do so violates CEQA as impermissible piecemealing. As explained above, CEQA defines "project" as the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment." CEQA Guidelines § 15378 (a).

CEQA mandates "that environmental considerations do not become submerged by chopping a large project into many little ones -- each with a minimal potential impact on the environment - which cumulatively may have disastrous consequences." *Bozung v. LAFCO* (1975) 13 Cal.3d 263, 283-84; *City of Santee v. County of San Diego* (1989) 214 Cal.App.3d 1438, 1452. In the CEQA case, *Laurel Heights Improvement Association of San Francisco, Inc. v. Regents of University of California*, the court found that before undertaking a project, the lead agency must assess the environmental impacts of all reasonably foreseeable phases of a project. (1988) 47 Cal. 3d. 376, 396-97. In that case, the Supreme Court found that the EIR was inadequate for failure to assess impacts of a second phase of a pharmacy school's occupancy of a new medical research facility. The courts have also articulated that a public agency may not segment a large project into two or more smaller projects in order to mask serious environmental consequences. A-26

The *Kings County* court explained that project impacts cannot be divided to avoid CEQA. 221 Cal.App.3d 692, 716. In that case, an EIR for a proposed coal-fired cogeneration power plant was found to be inadequate in part because the City of Hanford divided the emissions into two categories – on-site emissions resulting from fuel handling and combustion, and secondary emissions resulting from off-site transportation of the fuels. *Id*. at 714. Such separation of impacts, however, was found to be impermissible. "The requirements of CEQA cannot be avoided by chopping up a proposed project into bite-sized pieces which, individually considered, might be found to have no significant effect on the environment." *Id*. at 716.

In an Oakland airport expansion case, the court again explained that CEQA prohibits the "piecemealing" of a project. Citing Cal. Public Res. Code Section 21002.1(d), it explained that it is essential to "consider[ ] the effects, both individual and collective, of all activities involved in a project." *Berkeley Keep Jets Over the Bay Committee v. Board of Port Commissioners* (2001) 91 Cal.App.4th 1344, 1385. The court further explained:

> [A] curtailed or distorted project description may stultify the objectives of the reporting process. Only through an accurate view of the project may affected outsiders and public decision-makers balance the proposal's benefit against its environmental cost, consider mitigation measures, assess the advantage of terminating the proposal... and weigh other alternatives in the balance. An accurate, stable and finite project description is the sine qua non of an informative and legally sufficient EIR.

Here, SCE has divided its various 2007-2012 capital investments between this sale proceeding A-26
and its General Rate Case. It has further divided these investments into various categories such as reliability and environmental compliance. However, as explained above, according to SCE's own admission, these individual project components are interrelated because they were meant to ensure that "'Four Corners retains some residual value' should SCE subsequently divest its interest." CPUC Rulemaking 06-04-009 (Decision 10-10-016), filed on April 13, 2006 at p.15 (emphasis added) (Attached as Exhibit C). Thus, all of SCE's 2007-2012 capital investments in Four Corners should have been evaluated as a single project. And, more specifically, with respect to its 2012 investments, SCE itself states that "[i]n this proceeding, SCE only seeks Commission approval of these 2012 expenditures ***as part of overall approval of the proposed sale.***" Application 10-11-010, Exhibit SCE -02 (SCE May 19, 2011 Rebuttal Testimony), p.12:lines 17-21. Thus, a revised CEQA document that analyzes the Project as a whole must be recirculated for public review and comment.

III. CONCLUSION

A-27

For the above reasons, the CPUC must prepare an EIR to review the Project, involve the public, and mitigate significant environmental impacts.

Sincerely,

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Re: Review of Initial Study/Negative Declaration for the Proposed Sale of Southern California Edison's Ownership Share of the Four Corners Generating Station

Dear Ms. Peesapati,

Per your request, I have evaluated the Initial Study/Negative Declaration ("IS/ND") prepared by the California Public Utilities Commission ("CPUC") as the lead agency under the California Environmental Quality Act ("CEQA") for the proposed sale of Southern California Edison ("SCE") ownership share of the Four Corners Generating Station ("Four Corners")[1], for potential environmental impacts with respect to emissions of greenhouse gases. B-1

My qualifications as an environmental expert include a doctorate in Environmental Science and Engineering ("D. Env.") from the University of California Los Angeles. My professional experience in the environmental field includes the areas of air quality and global climate change. In my professional practice, I have reviewed and commented on dozens of CEQA documents including numerous power plants. My current resume is attached to this letter. B-2

Background

Four Corners is a 2,100-Megawatt ("MW"), five-unit, coal-fired electric generating station located in northwestern New Mexico on the Navajo Nation Indian Reservation. Four Corners is jointly owned by six entities as tenants-in-common; SCE currently owns 48% of Units 4 and 5, 32% of the 500 kilovolt ("kV") switchyard, 12% of the 345 kV switchyard, 48% of B-3

[1] California Public Utilities Commission, Four Corners Generating Station Project, Navajo Nation Indian Reservation, San Juan County, New Mexico, Draft Initial Study/Negative Declaration, September 2011, prepared by RMT, Inc.

the 345-500 kV transformer and connection to reserve auxiliary power source, 3.46% of the reserve auxiliary power source, and 43.2% of the connection to the 345 kV switchyard facilities.[2] SCE's application to the CPUC includes the following three elements: 1) SCE seeks to sell its interest in Four Corners to Arizona Public Service Company ("APS"); 2) SCE seeks CPUC approval for SCE's proposed ratemaking treatment with respect to the proposed sale transaction and proceeds; and 3) SCE seeks authority to make 2012 capital expenditures at Four Corners to operate the plant safely through closing of the purchase and sale agreement.[3] B-3

The IS/ND determines that the sale of SCE's interest in Four Corners is considered "a project under CEQA" because the sale will have a physical effect on the environment in California in the form of greenhouse gas emissions. The IS/ND claims without any further explanation that the second and third elements of SCE's application are not subject to CEQA review.[4] The IS/ND simply ignores the other aspects of the Project, including major modifications made to the plant beginning in 2007 to support the sale. B-4

The IS/ND's Analysis of Potential Operating Scenarios as a Result of the Proposed Sale Is Erroneous and Fails to Identify Significant Impacts Due to Emissions of Greenhouse Gases

Discussion of IS/ND Scenarios

The IS/ND presents three potential scenarios for connected actions that may be taken by APS as a result of the proposed sale:

Scenario 1: Units 1-3 shut down; output of Units 4-5 reduced by 103 MW to balance the capacity gained in Units 4-5 as a result of purchasing SCE's 48% share. B-5

Scenario 2: Units 1-3 shut down; Units 4-5 operated at maximum capacity without occurring outages for maintenance.

Scenario 3: Units 1-3 maintained at current capacity; Units 4-5 operated at peak capacity.[5]

The IS/ND rejects Scenario 3 "because APS has already stated its intention to close Units 1-3 at some future date, and because the energy projection that would result under this scenario far exceeds the demands of APS's customers." The IS/ND analyzes Scenario 2 as a

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[2] IS/ND, p. 2-2.

[3] IS/ND, p. 2-3.

[4] *Ibid*.

[5] IS/ND, p. 2-6 and Notes to Table 3.1-1, p. 3-4.

"reasonable worst-case scenario." [6] I disagree with the IS/ND's selection of a reasonable worst-case scenario regarding the for operation of Units 1-5 after sale of SCE's share of interest in Four Corners to APS and its calculations of potential change in greenhouse gas emissions because, among other things, it is not supported by fact.

First, the IS/ND's rejection of Scenario 3 relies on APS's unenforceable proposal to shut down Units 1-3 to resolve its federal Clean Air Act liabilities. However, APS's unenforceable settlement offer to the U.S. Environmental Protection Agency ("EPA") is insufficient evidence under CEQA to justify the exclusion of Scenario 3 from analysis. According to APS, Four Corners is "currently faced with uncertainty on all sides," including the potential costs of implementing controls under the federal Clean Air Act's Best Available Retrofit Technology ("BART") requirements of $1 billion; a petition by the National Parks Conservation Association to the United States Department of the Interior and Agriculture to certify to the United States Environmental Protection Agency ("EPA") visibility impairment reasonably attributable to Four Corners; a Notice of Intent to Sue from Earthjustice concerning alleged New Source Review ("NSR") and New Source Performance Standards ("NSPS") under the federal Clean Air Act; an EPA Clean Air Act §114 request for information concerning historic plant projects, presumably in the context of an NSR investigation; in addition to a "myriad of additional environmental regulations in the future including mercury, coal combustion residues, ozone, carbon, and others." It is in the context of these uncertainties that APS proposed to EPA a shutdown of Units 1-3.[7] Yet, the acceptance and realization of this proposal is far from certain. In other words, because APS has not made any enforceable commitment to shut down Units 1-3, either as a condition of the sale or elsewhere, any potential future shutdown cannot be considered part of the "project" under CEQA. It should also be noted that SCE would have no control over the ultimate fate of Units 1-3 after the sale. B-5

Second, even if APS's November 24, 2010 proposal materializes and Units 1-3 will be shut down, this shutdown will not occur before 2014.[8] This leaves at least two full years after the sale but before shutdown when all five units could operate at full capacity. Temporary impacts are not exempt from CEQA. For example, CEQA requires disclosure, analysis and mitigation of construction and noise impacts, both of which are temporary in nature. B-6

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[6] IS/ND, pp. 2-5 to 2-6.

[7] Edward Z. Fox, APS, Letter to Jared Blumenfeld, U.S. Environmental Protection Agency, Re: EPA R-09-OAR-2010-0683: Source Specific Federal Implementation Plan for Implementing Best Available Retrofit Technology for Four Corners Power Plant: Navajo Nation, November 24, 2010.

[8] *Ibid*.

Third, Units 4-5 have undergone or are proposed to undergo extensive capital improvements to facilitate the sale:

The modifications to the Unit 4 boiler include, but are not limited to: replacement of the pendant reheater section and the outlet header for that section; replacement of the second stage pendant superheater section; replacement of the nose portion of the furnace section; replacement of the baskets in the hot and cold ends of the air heaters associated with the boiler; upgrade of the capacities of the pulverizers associated with the boiler; and upgrade of the pulverizers associated with the boiler by replacing and/or upgrading the classifiers.

The modifications to the Unit 4 turbine/generator include, but are not limited to: replacement of the high pressure section of the main turbine, along with turbine controls; replacement of the fourth-stage rows of blades in the low-pressure sections of the main turbine; replacement of the second stage rows of blades in one of the low-pressure sections (section B) of the main turbine; replacement of one or more rows of blades in the intermediate-pressure section of the main turbine; rewinding of the rotor (field) in the generator associated with the high-pressure turbine; re-wedging of the generator associated with the low-pressure turbine; and replacement of one or more of the high-pressure feedwater heaters.

The modifications to the Unit 5 boiler include, but are not limited to: boiler tube replacements; replacement of the lower part of the furnace section; replacement of the pendant reheater section, along with the outlet header for that section; replacement of the horizontal reheater section; replacement of the first stage pendant superheater section; replacement of the second stage pendant superheater section; replacement of the nose portion of the furnace section; replacement of the baskets in the hot and cold ends of the air heaters associated with the boiler, and replacement and upgrade of pulverizers associated with the boiler by replacing and/or upgrading the classifiers. B-7

The modifications to the Unit 5 Turbine/Generator include, but are not limited to: replacement of the high pressure section of the main turbine, along with some or all of the turbine controls; replacement of the fourth-stage rows of blades in the low-pressure sections of the main turbine; replacement of one or more rows of blades in one of the low-pressure sections (section A) of the main turbine; replacement of one or more rows of blades of the intermediate-pressure section of the main turbine; and rewinding of the rotor (field) in the generator that is associated with the low-pressure turbine.[9]

[9] Southern California Edison Company, Comments of Southern California Edison Company (U 338-E) on Assigned Commissioner and Administrative Law Judge's Ruling Entering Additional Information into the Record and Seeking Comments, Docket 07-OIIP-01, November 24, 2008, Appendix A; attached as Exhibit 1.

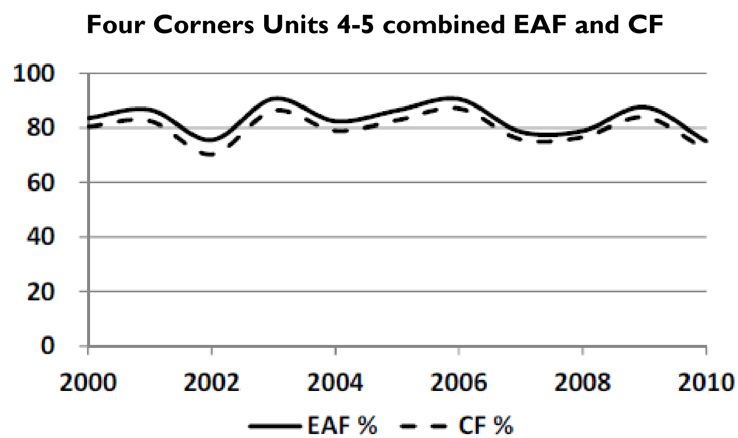
In addition, SCE has listed a number of future modifications in its recent "updated testimony" proposed to the CPUC in its ongoing General Rate Case.[10] These modifications can reasonably be expected to increase reliability and, thus, availability of the units. In fact, the *stated purpose* of some of these modifications is to improve the reliability of Units 4-5.[11] B-7

Under CEQA, the IS/ND must evaluate potential emissions for future operations from the project subject to the Act. The following sections present an analysis of a) the potential increase in greenhouse gas emissions due to improved reliability of Units 4-5 resulting from the above discussed capital improvements and b) a revised worst-case emission scenario. B-8

Analysis of Improved Reliability Scenario

As demonstrated below, even a conservative approach that only accounts for the potential improvement in reliability resulting from the 2007-2012 capital investment in Units 4-5 would result in emission increases that are significant.

SCE has stated that, during the last 11 years, Units 4 and 5 have had an average equivalent availability factor ("EAF")[12] of 83%.[13] The following graph provided by SCE shows that CF closely tracked EAF in those years. B-9



[10] Southern California Edison Company, Four Corners Capital Expenditure Update, Before the Public Utilities Commission of the State of California, October 2011; attached as Exhibit 2.

[11] *Ibid*, p. 7, Section 6. CBI 12-10 Exciter AC Enclosure, U 4&5: "The purpose of this $0.946 million (SCE Share) project *is to enhance the reliability* of the respective Unit 4 and Unit 5 main generator high pressure and low pressure excitation control systems, thereby avoiding unit outages and potential damage to the generators." [*Emphasis* added.]

[12] Equivalent Availability Factor ("EAF") is the percentage of time that the units are available for full rated generation operations, whether or not they are actually dispatched to full rated load when available to do so.

[13] Southern California Edison, 2012 General Rate Case Rebuttal Testimony, Volume 6 (Part 2), Coal Capital Expenditures, Chapters IX-XIII, before the Public Utilities Commission of the State of California, Generation, July 5, 2011, pp. 20-21; attached as Exhibit 3.

As the above figure shows, the units have always been operated at the maximum output of which they were capable at the moment. SCE stated that the units were operated at an average capacity factor ("CF")[14] of 82.1%. This also means that APS has in the past always been taking its share of every MW Units 4-5 could provide since it is not plausible that what Units 4-5 provide exactly matched APS's demands. Thus, it is likely that for most or all hours, APS would take more MW from those units than they can currently receive. (In contrast, analysis of EPA's Clean Air Markets ("CAM") data for Four Corners shows that for Units 1-3 CF do not always closely track EAF.)

As discussed above, Four Corners has undergone or is scheduled to undergo a large number of modifications. These modifications can reasonably be expected to increase reliability and, thus, availability of the units. Robert Koppe, an expert on coal-fired power plants, summarizes the effect of past and planned capital expenditures at Four Corners as follows:

> <u>Capital Expenditures and EAF</u>
>
> It is widely recognized in the industry that the EAF achieved by a coal unit depends on the amount of money that is spent on that unit.[1] Industry experience has shown that large coal units are capable of EAFs around 90%.[2] During the last decade, utilities have reduced spending on coal units and EAFs have decreased. It is still possible for the industry to achieve higher average EAFs for coal units. All that is required is increased expenditures. B-9
>
> If the value of the power from a coal unit is relatively low, the expenditures that can be economically justified will be relatively low, and the resulting EAF will be relatively low. If the value of power from a unit is relatively high, higher expenditures will be justifiable, and the resulting EAF will be relatively high.[3] It appears that the value of power from Four Corners 4 and 5 is much greater than the average value in the industry.[4] This means that it should be economically justifiable for the units to achieve above-average EAFs.
>
> The preceding all indicates that sufficient expenditures (but limited to expenditures that are economically justifiable) should result in Four Corners 4 and 5 having EAFs that are well above the industry average, and possibly as high as 90%.
>
> <u>Historical EAFs for Four Corners 4 and 5</u>
>
> The recent (2008 through the present) campaign of upgrades to Four Corners 4 and 5 has involved a very large amount of work. The extent of the upgrades is considerably greater than what has been done at most coal units during most time periods.

[14] Capacity Factor ("CF") is the percentage of actual Megawatt-hour generation each year compared to the theoretical maximum generation possible if the generating units were to operate at its full rated capacity 24 hours per day, 365 days per year.

At Four Corners 4 and 5, allowing so many needed upgrades to accumulate would tend to have two effects. First, deteriorated components would result in more unplanned outages, which would decrease the EAFs for the units. Second, the need to perform so many upgrades would result in the need for very long planned outages, which would also reduce the EAFs for the units. Once the upgrades are completed, the result should be less unplanned outage time and less planned outage time, resulting in an increase in the average EAFs for the units.

Much of the upgrade work at the units was only done during 2008-2010, and some is still to be done. Of course, the benefits of the work do not show up in the data through 2010. Once the upgrades have been completed, there should be fewer unplanned outages and shorter planned outages. Then the EAFs of the unit should increase.

Footnotes to above text:

[1] This is common sense. In addition, several utilities and consultants have shown this effect using statistical analysis of plant data.

[2] Many individual coal units have achieved such EAFs.

[3] Consider a situation where a section of boiler tubes is starting to develop leaks. If the value of power from the unit is relatively low, the utility will have to wait for years until the frequency of leaks is relatively high. Only then will the replacement of the tubes be economically justifiable. If the value of power from the unit is relatively high, the utility will be able to justify replacing the tubes immediately. The result will be fewer leaks, and a higher EAF. B-9

[4] SCE has filed cost-benefit analyses for a number of upgrades to the units. These analyses show replacement power costs for the units that are much higher than what is typically seen in the industry. As a result, they show payback times for the projects that are much shorter than is typically seen in the industry.[15]

Mr. Koppe's discussion regarding the accumulation of upgrades and corresponding drop in EAF appears to be supported by SCE's recent testimony that availability in 2011 has dropped below 80%.[16]

Based on the discussion above, an increase of only one percent in the EAF for Units 4-5 (for example, from 83% to 83.83%) due to improved reliability can be reasonably expected to lead to additional operation of these units of one percent. Therefore, it can be expected that an increase in the EAF of Units 4-5 of one percent would result in a corresponding increase in their CF of one percent. This would result in a corresponding one percent increase in greenhouse gas emissions. An increase of one percent in EAF due to improved reliability would result in additional emissions of 98,903 tons of CO_2-e per year.[17] Larger increases in

[15] Email from Robert Koppe to Petra Pless, November 3, 2011.

[16] Testimony by Tom Ware, November 3, 2011 Evidentiary Hearing on SCE's Update Testimony in Proceeding No. A.10-11-015.

[17] Units 4-5 10-year (2000-2009) average CO_2-e emissions in tons/year:
CO_2: 10,842,725 tons CO_2/year × 0.01 = 108,427 tons CO_2/year
CH_4: 108,427 tons CO_2/year × 2.23E-04 CH_4/CO_2 = 2,418 tons CO_2-e/year

EAF would result in proportionally larger increases in greenhouse gas emissions. Given the scope and number of SCE's capital investments in the plant to facilitate the sale and past capacity factors, an increase of 5 to 10 percent in reliability is reasonable. B-9

Analysis of Revised Worst-Case Emission Scenario

Typically under CEQA, potential future emissions are analyzed under a worst-case scenario. Here, the worst-case scenario for potential future emissions would include the operation of all five units at their maximum capacity, which is the assumed goal of the capital investments and resulting physical modifications to the plant. This approach is analogous to the IS/ND's analysis of Scenario 2. B-10

Emissions for this revised worst-case scenario can be calculated analogous to the methodology provided by the IS/ND, *i.e.*, Units 1-5 operating at maximum capacity for 8,760 hours per year (or 8,784 hours per leap year) without occurring outages for maintenance. These emissions correspond to the permitted potential to emit ("PTE") from EPA's Title V Permit for Four Corners.[18] Following the IS/ND's methodology, emissions of carbon dioxide ("CO_2") equivalent ("CO_2-e) greenhouse gases from the five units can be calculated as follows:

Total PTE for Units 1-3 for 2008-2013 from EPA's Title V Permit for CO_2 emissions:

PTE Unit 1:	2,290,543 tons CO_2/year[19]
PTE Unit 2:	2,290,543 tons CO_2/year[20]
PTE Unit 3:	3,041,187 tons CO_2/year[21]
Total PTE Units 1-3:	**7,622,273 tons CO_2/year**

N_2O: 108,427 tons CO_2/year × 5.26E-03 CH_4/CO_2 = 57,033 tons CO_2-e/year
Total 10-year average (2000-2009) CO_2-e emissions from Units 4-5: 10,902,176 tons CO_2-e/year;

Conversion to metric tons CO_2-e/year:
10,902,176 tons CO_2-e/year × 0.90718474 metric ton/ton = 9,890,287 metric tons CO_2-e/year;

One percent of Units 4-5 10-year (2000-2009) average CO_2-e emissions:
9,890,287 metric tons CO_2-e/year × 0.01 = 98,903 metric tons CO_2-e/year.

[18] *See* IS/ND, Appendix B, Table "Four Corners Plantwide Emissions" (PTE for Units 4 & 5) and Appendix C, Table "Four Corners Generating Station – Estimated GHG Emissions Under Scenario 2" (EPA Title V (2008-2013) Permitted PTE): 15,465,430 tons CO_2/year.

[19] IS/ND, Appendix B, Table "Four Corners - Plantwide Emissions."

[20] *Ibid*.

[21] *Ibid*.

Following the methodology provided by the IS/ND, the total PTE in CO_2-equivalent emissions for Units 1-3 for 2008-2013 can be calculated by applying following ratios for emissions of CH_4 and N_2O per unit of CO_2:

CH_4:	2.23E-04 tons CO_2-e from CH_4/ton CO_2 emitted[22]
N_2O:	5.26E-03 tons CO_2-e from N_2O/ton CO_2 emitted[23]

Applying these ratios to the above calculated total PTE for Units 1-3 in tons CO_2-e per year results in the following CO_2-equivalent emissions of CH_4 and N_2O:

CH_4:	1,700 tons CO_2-e/year
N_2O:	40,093 tons CO_2-e/year

Converting to metric tons per year[24]:

CO_2:	6,914,810 metric tons CO_2-e/year
CH_4:	1,542 metric tons CO_2-e/year
N_2O:	36,372 metric tons CO_2-e/year
Total CO_2-eq:	**6,952,724 metric tons CO_2-e/year**

B-10

Based on these emission calculations, potential changes in total CO_2-equivalent greenhouse gas emission from Units 1-5 compared to the baseline can be calculated as shown in the following table.

Greenhouse Gas Emissions under Revised Reasonable Worst-Case Scenario (metric tons CO_2-e/year)

	Emissions
PTE (Title V 2008-2013) Units 1-3	6,952,724
PTE (Title V 2008-2013) Units 4-5	14,106,855
Total future emissions (PTE Units 1-5)	**21,059,579**
Baseline emissions (2000-2009)	**14,510,980**
Net potential emission change	**6,548,599**

PTE for Units 1-3 and 4-5 and baseline from IS/ND, Appx. B, Table "Four Corners Plantwide Emissions", converted to metric tons CO_2-e/year
(1 ton = 0.90718474 metric ton)

As shown in the above table, potential emissions for operation of all five units at maximum capacity would result in an additional 6.5 million metric tons of CO_2-equivalent emissions per year compared to the baseline, *i.e.*, emissions during the past decade (2008-2009).

[22] IS/ND, Appendix C, Tables "Four Corners Generating Station – Estimated GHG Emissions Under Scenario 1" and "Four Corners Generating Station – Estimated GHG Emissions Under Scenario 2."

[23] *Ibid*.

[24] 1 ton = 0.90718474 metric ton.

Threshold of Significance for Greenhouse Gas Emissions

The IS/ND provides no quantitative threshold of significance for greenhouse gas emissions and instead provides the following two qualitative thresholds for determining whether emissions of greenhouse gases would result in a significant impact:

- Generate GHG [grenhouse gas] emissions, either directly or indirectly, that may have a significant impact on the environment.
- Conflict with an applicable plan, policy or regulation adopted for the purposes of reducing the emissions of GHGs.[25]

The first of these qualitative thresholds is nonsensical as it provides a circular argument: Emissions of greenhouse gases would be considered significant if the project would generate greenhouse gas emissions that may have a significant impact. Obviously, this threshold is not useful.

Given AB 32 and SB 1368's premise that California must *reduce*, not just maintain, current greenhouse gas emissions levels, it is my expert opinion that a significance threshold of zero should be applied to the project. There is no question that Four Corners already fails to comply with the CPUC's Emissions Performance Standard ("EPS") under SB 1368, thereby triggering the current sale. In this regulatory context, any increase in greenhouse gases from modifications associated with the sale should be considered significant under CEQA. B-11

The IS/ND's failure to use a quantitative threshold is anomalous given that other agencies have developed quantitative thresholds or are routinely relying on quantitative thresholds established by other agencies. For example, in 2010, the Bay Area Air Quality Management District ("BAAQMD") established a threshold of significance in its CEQA Guidelines which specifies that an industrial project will have significant adverse impacts due if it will generate more than 10,000 metric tons of CO_2-eq greenhouse gas emissions per year.[26] The South Coast Air Quality Management District has also published an interim significance threshold of 10,000 metric tons per year for projects that do not capture 90% of their greenhouse gas emissions.[27] As explained below, the Project carries significant greenhouse gas impacts based on these thresholds as well.

The Project's potential increases of greenhouse gas emissions by far exceed these quantitative thresholds: For example, the change in potential future maximum emissions

[25] IS/ND, p. 3-3.

[26] Bay Area Air Quality Management District, Adopted Air Quality CEQA Thresholds of Significance* - June 2, 2010; http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/CEQA/Adopted%20Thresholds%20Table_December%202010.ashx?la=en.

[27] http://www.aqmd.gov/hb/2008/December/081231a.htm at Table 1 (last visited on November 1, 2011)

compared to the baseline exceeds the BAAQMD's threshold of 10,000 metric tons of CO_2-eq greenhouse gas emissions per year by a factor of 655.[28] Even an increase of one percent in capacity due to increased reliability alone would exceed the BAAQMD's threshold of significance by a factor of 9.9.[29] Clearly, future emissions from Four Corners have the potential to result in significant impacts due to emissions of greenhouse gases.

B-11

Conclusion

Contrary to the IS/ND's claim, the sale of SCE's share of interest in Four Corners to APS is likely to have a significant adverse impact on the environment due to increased emissions of greenhouse gas emissions. I recommend that the CPUC conduct comprehensive environmental review of the project's potential impacts on climate change in a Draft Environmental Impact Report under CEQA.

B-12

Regards,

Dr. Petra Pless

Enclosures

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[28] (6,548,599 metric tons CO_2-e/year) / (10,000 metric tons CO_2-e/year) = 654.9.

[29] (9,890,287 metric tons CO_2-e/year) / (10,000 metric tons CO_2-e/year) = 9.89.

e

ENVIRONMENTAL DEFENSE FUND

finding the ways that work

BY EMAIL

November 3, 2011

Mr. Andrew Barnsdale
California Public Utilities Commission
c/o RMT, Inc.
4 West 4th Avenue, Suite 303
San Mateo, CA 94402

Dear Mr. Barnsdale,

We respectfully submit these comments on the Draft Initial Study/Negative Declaration ("IS/ND") prepared for the Southern California Edison Four Corners Generating Station Project.

The proposed transaction has the potential to carry significant environmental benefit to California and the Four Corners region should the transaction result in retirement of Units 1-3. As the Draft IS/ND notes, APS has proposed to EPA an alternative plan for satisfying the requirements of the Clean Air Act's Regional Haze program. Under this plan, APS has proposed to close Units 1-3 by 2014 and to install selective catalytic reduction technology (SCR's) on Units 4 and 5 by 2018. As shown in Table 1, the retirement of Units 1-3 would carry significant environmental benefits, reducing emissions of mercury, sulfur dioxide, particulate matter, nitrogen oxides, and greenhouse gases by significant amounts. C-1

Scenario 3 of the Draft IS/ND estimates emissions from Units 4 and 5 operating at peak capacity and from Units 1-3 operating at current capacity. The Draft IS/ND states that this scenario was rejected from further consideration because "APS has already stated its intention to close Units 1-3 at some future date, and because the energy production that would result under this scenario far exceeds the demands of APS's customers."

This analysis does not give sufficient consideration to the possibility that Units 1-3 might not be retired. At this time, APS is under no obligation to EPA or any other entity to retire these units. Moreover, should APS lose access to the 315 MW of power it uses from the Navajo Generating Station ("NGS"), one possible source of replacement power would be one or more of the older Four Corners Units. NGS faces the same suite of environmental requirements as FCPP, and at present the NGS owners have not publicly indicated how they seek to satisfy those requirements. Should APS need to replace the power currently generated by NGS, FCPP's older units would be a ready alternative. If APS had a contractual obligation to SCE to retire Units 1-3 by a date certain in 2014, an option that could be considered as mitigation of possible environmental effects of the transaction under consideration, Scenario 3 might be more reasonably rejected. C-2

The Draft IS/ND also states, at the top of page 2-6, that Units 1-3 are expected to be retired at "some" future date. APS' proposal to EPA that the units would be retired in 2014 is essential to determining potential impacts of the transaction proposed in this project. Because APS currently has the option to retire Units 1-3 at a date later than that assumed in the analysis, regardless of the proposal contained in the November 24, 2010 letter from APS to US EPA, it would be inappropriate for the Commission to ignore emissions from these units during that extended timeframe. We therefore suggest that the final IS/ND explicitly incorporate the proposed 2014 retirement date into its analysis and discussion of scenarios. C-3

Finally, we note that nothing in the record currently shows that the FCPP transaction will be subject to National Environmental Policy Act. Performance of NEPA review is a precondition for a project analysis to avoid any discussion or analysis of out of state impacts where the project is located out of state. As a result, under CEQA Guideline15277, impacts of local air pollutants and water usage should be considered in the final analysis. C-4

Thank you for taking these comments into account.

Sincerely yours,

Pamela Campos
Attorney
Environmental Defense Fund

Tim O'Connor
Attorney
Environmental Defense Fund

Table 1

Summary of Health and Environmental Benefits of the APS Proposal

Pollutant	Emissions Reduced*	Benefits
Nitrogen Oxides Closure of Units 1-3 SCR on Units 4, 5	 14 thousand tons per year 20 thousand tons per year	Improvements in human health from reductions in ozone and fine particulate matter exposure. Significant Improvement in Visibility in the region around FCPP, including reduction of peak impacts of FCPP at 16 Class I areas by one half to two thirds Lowering of nitrogen deposition to desert ecosystems
Sulfur Dioxide	2.5 thousand tons per year	Improvement in human health from reductions in fine particulate matter exposure Small improvement in visibility in the region
Mercury	300 pounds per year	Less human exposure to mercury Less mercury deposition to ecosystems
Fine Particulate Matter	678 tons per year	Small improvement in human exposure Small Improvement in local visibility
Carbon Dioxide	3 to 5 million tons per year	Contribution to addressing global increase in greenhouse gas emissions.

* Based on 2009 Emissions reported in EPA's Clean Air Markets Database and APS Proposal submitted to EPA.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL® Company

November 3, 2011

VIA EMAIL

Mr. Andrew Barnsdale
California Public Utilities Commission
c/o RMT, Inc.
4 West Fourth Ave., Suite 303
San Mateo, CA 94402
E-mail: FourCorners@rmtinc.com

Subject: Southern California Edison Company Comments on the Draft Initial Study / Negative Declaration for the Approval of Agreement to Sell its Interests in Four Corners Generating Station (A.10-11-010)

Dear Andrew,

Enclosed please find Southern California Edison's (SCE) comments on the Draft Initial Study / Negative Declaration (Draft IS/ND) for SCE's Section 851 Application to sell its interests in Four Corners Generating Station. SCE's general and specific comments are in description format and then some additional comments are provided in table format, for accuracy and clarity, that list the page number and text reference along with suggested revisions. D-1

SCE appreciates your time and attention in addressing its comments on the Draft IS/ND. If you have any questions, please don't hesitate to call me at (626) 302-3613.

Sincerely,

Ryan Stevenson
Regulatory Affairs

P.O. Box 800
2244 Walnut Grove Ave.
Rosemead, CA 91770

Southern California Edison Company
Comments on the Draft IS/ND for the Proposed Sale of SCE's Interest in the Four Corners Generating Station
November 3, 2011

General Comment:

SCE disagrees with the threshold conclusion of the Draft IS/ND that the proposed sale of SCE's Four Corners interest is subject to environmental review under the California Environmental Quality Act (CEQA). Under the CEQA Guidelines and under CPUC and judicial precedent, the proposed sale falls within the "common sense" and the "existing facilities" exemptions to CEQA (CEQA Guidelines Sections 15061(b)(3) and 15301, respectively), and therefore the sale is categorically exempt from CEQA review.

SCE has addressed this point in detail in prior filings in this CPUC docket, and especially in SCE's December 3, 2010, *Amendment to the Application* and SCE's February 11, 2011, *Response to Motion of Sierra Club Motion on CEQA Applicability Issue.* SCE therefore incorporates those two filings here by reference, and SCE summarizes the point again here briefly.

The proposal that is before the CPUC for its discretionary approval is the particular agreement that APS and SCE have reached for the purchase and sale of SCE's interest in Four Corners, and not the more fundamental fact that SCE will be ending its ownership participation in Four Corners and APS and the other plant co-owners may continue to own and operate the plant without SCE. Even without CPUC approval of the proposed sale, SCE must and will exit from its participation in Four Corners under SB 1368, the California statute barring "new ownership investment" by SCE in power plants that, like Four Corners, do not meet California's greenhouse gas (GHG) emissions performance standard (EPS). SCE's departure from Four Corners ownership is not discretionary or subject to CPUC disapproval. Also, even without CPUC approval of the proposed sale, APS and the other Four Corners co-owners are *not* barred from continued investment in and operation of the plant, given that they are not California utilities or otherwise subject to SB 1368 or the California EPS. Therefore the other co-owners may pursue obtaining SCE's Four Corners share through other avenues, such as a property partition action in New Mexico state court or waiting for SCE's contractual ownership interest to terminate automatically in 2016, and they may continue operating the plant. Any resulting environmental effects would be the same regardless of whether the transfer of SCE's plant interest took place through CPUC sale approval or otherwise. Therefore, the proposed sale that is actually before the CPUC for its approval has no reasonably foreseeable environmental impacts, and is categorically exempt from CEQA review. D-2

Assuming for discussion purposes that the proposed sale is subject to CEQA review, the Draft IS/ND is correct in concluding that the sale will have no adverse environmental impacts, and a Negative Declaration is appropriate under CEQA. SCE therefore supports the final conclusion of the Draft IS/ND, but has the following comments and recommendations regarding specific portions of the Draft IS/ND. D-3

<u>Specific Comment 1</u>: Draft IS/ND Section 1.2, page 1-1:

> ***"The physical change that could affect California involves changes in the emissions of greenhouse gases."*** **(See also, Section 2.4, page 2-4, footnote 2; and Section 2.4.2, page 2-6.)**

The Draft IS/ND limits its discussion to any potential environmental effects from the proposed sale that could occur within the state of California, and consequently it considers only the potential impact of GHG emissions. This approach is clearly correct under CEQA, in these factual circumstances, but SCE recommends that an underlying reason should be expressly mentioned in the Final Negative Declaration (ND).

A CEQA statutory provision, Public Resources Code Section 21080(b)(14), expressly provides that CEQA "does not apply" to any project that is located outside of California and that will be subject to environmental impact review under the National Environmental Policy Act (NEPA) (or under another's state NEPA-equivalent state law); the only carve-out from this statutory exemption is that any "emissions or discharges" that would have a significant effect on the environment in California are still subject to CEQA review. Even assuming *arguendo* that any impacts from the continued operations of Four Corners after the sale could be attributed to the proposed sale, those impacts will be subject to environmental review under NEPA for the reasons discussed below, and so they are statutorily exempt from CEQA review under Section 21080(b)(14), except for any potential emissions impact within the state of California. D-4

The continued operation of Four Corners by APS and the other plant co-owners has required an extension of the plant's site lease, which otherwise would terminate in 2016. The Navajo Nation and all of the Four Corners owners except SCE have accordingly executed a long-term extension of the plant's site lease. This lease extension, and related grants of property rights, require the approval of the U.S. Bureau of Indian Affairs (BIA), which in turn triggers environmental review under NEPA. Similarly, the related extension of operations of the nearby Navajo Mine, which provides all of Four Corners' coal supply, requires permit approval from the U.S. Office of Surface Mining and Reclamation (OSM), also triggering NEPA review of any related environmental impacts. Therefore, any possible environmental effects even arguably related to the proposed sale will be the subject of environmental review under NEPA, and, except for any in-California emissions impacts, they are statutorily exempted from review under CEQA.

<u>Specific Comment 2</u>: Draft IS/ND "Scenario 1," discussed at Section 2.4.1, page 2-5, and Section 3.1.2, pages 3-4 to 3-5.

From SCE's understanding of the Draft IS/ND, "Scenario 1" appears to undercount the GHG emissions to be reasonably expected in this Scenario, for two separate reasons, as explained below. Even when these emissions are properly counted, the Draft IS/ND is still correct that there will be no emission increase from SCE's sale of its Four Corners share to APS – on the contrary, a significant emissions decrease is more reasonably D-5 foreseeable – and so the Draft IS/ND is correct in concluding that there will be no negative environmental impact. However, SCE recommends that the Final ND's analysis include these emissions for purposes of a complete record.

First, although the Draft IS/ND correctly notes that after the sale SCE will need to replace its Four Corners interest with other energy sources (and the Draft IS/ND correctly notes that these will necessarily be cleaner energy sources than Four Corners), the discussion of the Scenario 1 GHG emissions apparently assumes no GHG emissions at all from this SCE replacement generation. SCE believes it is reasonable to assume an overall GHG emissions rate for this SCE replacement generation of approximately 833 lbs/MWhr (an emissions rate achieved by new combined cycle gas turbine units) to approximately 1100 lbs/MWhr (i.e., an emissions rate minimally compliant with the current EPS under SB 1368). SCE notes that the CARB default assumption for generic gas-fired energy imported from the Southwest is squarely within this range, at 959 lbs/MWhr. Using any of these three proxy emission rates yields a significant emissions decrease associated with the proposed sale, as shown in Table 1 below, because the emissions of the SCE replacement generation will not come close in any case to canceling out the emission reductions from APS's expected shutdown of Four Corners Units 1-3.

As an assumption of the longer-term emissions from this replacement generation, moreover, these emission rates, and especially the higher 1100 lbs/MWhr rate, may be quite conservative (i.e., overstating the expected emissions), in that they do not take into account two important factors: (i) California's mandatory renewables portfolio standard; and (ii) the GHG cap-and-trade program now being implemented under California's AB 32, which incorporates a significantly declining overall cap on GHG emissions. Because of these two legal requirements, the SCE replacement generation's overall GHG emission rate should be expected to decline significantly over time.[1] Even ignoring these considerations, however, and simply assuming these constant emissions rates, the emissions from the SCE replacement generation will be significantly less than the emission reductions from the Four Corners Units 1-3 shutdown, as reflected in Table 1. D-5

Second, the Draft IS/ND notes that APS's expected shutdown of Four Corners Units 1-3 and acquisition of SCE's 48% share of Units 4-5 will leave APS with a net gain of generating capacity (equivalent to an approximately 103 MW output gain as averaged over an entire year). The Draft IS/ND notes that APS will not generate more power than needed to serve its load requirements, but then anticipates that APS will reduce its output from Four Corners Units 4-5 by the full corresponding 103 MW. SCE would not view this as the most reasonable assumption, at least for CEQA base-case purposes. A more likely scenario is that APS will instead reduce its output or power purchases from other, gas-fired, generation sources that have been more expensive sources than Four Corners Units 4-5, and it will utilize Four Corners Units 4 and 5 at or near those Units' full

[1] Also, even if the GHG emissions rate of this replacement power did not decline, it would necessarily mean the removal of corresponding amounts of GHG allowances from California's cap-and-trade allowance market, for AB 32 compliance, with the same end result of a total net reduction of GHG emissions.

historical capacity factors. The reduction in output from the gas-fired sources will still mean significant GHG emissions reductions that should be reflected in the Final ND, as shown in Table 1 below, but not the same level of GHG reductions that would result from the same output reduction at the coal-fired, Four Corners units.

Table 1 - Summary of Generation Scenarios GHG Impacts

Future Greenhouse Gas Emissions	Generation MW-hrs/yr	See Note	CO_2 eqv. Units	Combined Cycle	CARB Default Imported	SB 1368 Compliant
SCE replacement generation emission rate	n/a	1	lbs/MW-hr	833	959	1,100
SCE replacement percent of interim standard	n/a	2	percent	76%	87%	100%
APS operates Units 4 & 5	10,741,700	3	tonnes/yr	9,769,900	9,769,900	9,769,900
APS reduces other gas-fired generation	(900,200)	4	tonnes/yr	(479,800)	(479,800)	(479,800)
Net APS generation	9,841,500	5	tonnes/yr	9,290,100	9,290,100	9,290,100
SCE replacement generation	5,156,000	6	tonnes/yr	1,948,200	2,242,900	2,572,600
Combined net APS and SCE generation	14,997,500	7	tonnes/yr	11,238,300	11,533,000	11,862,800
Four Corners plantwide baseline	14,997,500	8	tonnes/yr	14,386,300	14,386,300	14,386,300
Net Change	**-**	**9**	**tonnes/yr**	**(3,148,000)**	**(2,853,300)**	**(2,523,500)**

Notes:

Annual GHG emissions are in units of metric tonnes CO_2 equivalents (1,000 kg or 2,204.6 lbs)

(1) CO_2 equivalents based on California Climate Action Registry, January 2009

(2) PUC Decision No. 07-01-039, January 25, 2007

(3) Historical average 79.6% capacity factor based on 770 MW rating for each unit

(4) Average load reduction of 103 MW for 8,760 hrs/yr (assumes 34% efficiency for 1,175 lbs CO_2 eqv/MW-hr, see note 1)

(5) Parity with historic APS generation including Units 1, 2, & 3 (assumes shutdown)

(6) Parity with historic SCE generation share from Units 4 & 5 (48 percent)

(7) Parity with historic plantwide generation

(8) Historic plantwide generation (11 years average 2000-10)

(9) Change = combined - baseline; all scenarios result in GHG reductions; results represent a reasonable range

D-5

If recent declines in natural gas prices continue or accelerate, APS (and/or other Four Corners co-owners) may indeed reduce the output from Four Corners Units 4-5 over time – possibly even beyond 103 MW – but SCE does not consider it appropriate to assume a full, constant, 103 MW reduction at Four Corners Units 4-5 for CEQA base-case purposes.

However, even assuming that Four Corners Units 4-5 continue to operate at their full historical capacity factors and all APS output reductions come elsewhere, from gas-fired generation, and also taking into account the GHG emissions of SCE's replacement generation as discussed above, there is no GHG emission increase associated with SCE's proposed sale of its Four Corners interest, and on the contrary there is a significant emissions decrease. As shown in Table 1, even after taking into account both of these factors, the net outcome is a GHG emissions reduction in the range of approximately 2.5 million metric tons per year to over 3.1 million metric ton per year. D-5

<u>Specific Comment 3</u>: Draft IS/ND "Scenario 2," discussed at Section 2.4.1, page 2-5, and Section 3.1.2, pages 3-4 to 3-5.

The Draft IS/ND's "Scenario 2" is based on an assumption that, following the purchase of SCE's interest in Four Corners Units 4-5, APS operates both of those Units continuously at 750 MW each, all hours of the year, which is very close to a 100% capacity factor.[2] The Draft IS/ND indicates that this Scenario is considered unlikely, but is meant as a "reasonable 'worst case' scenario." However, operation of these units (or indeed any power plant generating units) at or near a 100% capacity factor is not a "reasonable," or even possible, scenario, and so Scenario 2 is not appropriate for inclusion in the Final ND even as an illustration of the extreme outer bounds of potential resulting GHG emissions.

Like all power plant generating units, Four Corners Units 4-5 must periodically reduce load or come off-line completely, for necessary repairs and maintenance (both scheduled and unscheduled) either on the generating units themselves or on various other parts of the power plant's extensive infrastructure. Operations at 100% capacity are purely theoretical, and not realistically achievable, for any power plant. The Units have never had an annual capacity factor at or near 100% since they were put in service in the early 1970's. And there is no factual basis for assuming even that these Units' capacity factor could be materially increased in the future over their historical level, much less that the Units could run at or close to a 100% capacity factor. For one thing, APS, SCE and other plant co-owners have always had strong economic incentive over the years to run Four Corners Units 4-5 at or near the highest capacity factors that they could reasonably and safely achieve. As large, coal-fired units, Four Corners Units 4-5 are and always have been relatively low-cost generation sources for all the owners, and certainly for SCE. The sale of SCE's interest to APS would not improve the units' economics for APS or the other remaining co-owners, or introduce any other reason to assume any increase in capacity factors. Also, these Units' historical capacity factor of approximately 80% is very comparable to the capacity factors of other baseloaded, coal-fired generating units around the country, especially units of comparable age, further indicating that there is no room for any material improvement in the Units' capacity factors. D-6

SCE believes that Scenario 2 should be removed from the Final ND or, if it is kept in the Final ND at all, it must be clearly identified as a purely theoretical reference point.

[2] SCE refers here to "capacity factor" as the term is generally used in the power industry, meaning actual annual generating unit MWhr output as compared to the maximum theoretically possible output assuming the unit operated at full rated MW output for the entire 8,760 hours per year. The "capacity factor (HI)" data in the Draft IS/ND, Appendix B, is a different parameter, namely actual annual fuel consumption (heat input) as compared to a reference maximum annual fuel consumption level.

Additional Comments:

SCE also recommends a few other, more minor changes to the text of the Draft IS/ND, as explained below in Table 2. D-7

Table 2 – Additional Comments

No.	Section	Page	Draft IS/ND Text Reference	Comments
1.	Introduction	1-1	This Initial Study/Negative Declaration was prepared in accordance with the California Environmental Quality Act (CEQA) Guidelines Section 15063 to evaluate the potential environmental consequences of the sale of SCE's share of the Four Corners facility.	Edit recommended for accuracy and clarity. SCE owns and is requesting authorization to sell only a partial interest in Four Corners.
2.	1.1	1-1	The CPUC must determine whether to authorize the sale of SCE's share of the Four Corners facility pursuant to Section 851 of the Public Utilities Code.	Same as Comment 1 above.
3.	2.1.2	2-2	SCE also owns a portion of the Four Corners Generating Station ancillary facilities related to Units 4 and 5, as indicated in Table 2.1-2.	Edit recommended for accuracy and clarity.
4.	3.1.2	3-2	While this report addressed GHG impacts for new power plants and would not be directly applicable to an existing facility such as Four Corners, the ~~information in this~~ report includes information that may be considered appropriate to use as helpful reference and comparison information for evaluation of this project.	Edit recommended for accuracy and clarity. Portions of the report may have no applicability or relevance to an existing plant such as Four Corners.
5.	3.1.2	3-6	The plans and regulations that would be mandated under AB 32 would not apply to the Four Corners facility since it is not located in California, and the only California co-owner of the facility, SCE, will be selling all of its interest in the facility and will no longer import any Four Corners power into California. The purpose of the project would be to comply with California's Senate Bill 1368 which requires SCE to comply with ~~an Emissions Performance Standard~~ the EPS. Senate Bill 1368 bars SCE from making "new ownership investment" in any power plant not meeting the EPS; and Four Corners does not meet the EPS.	Edit recommended for a more complete and correct discussion regarding AB 32 and SB 1368.

ATTACHMENT B: CPUC DATA REQUEST TO SCE

STATE OF CALIFORNIA
Edmund G. Brown Jr., Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

December 21, 2011

Ryan Stevenson
Project Manager
Regulatory Policy & Affairs Dept.
Southern California Edison
2244 Walnut Grove Avenue, Quad 3D, 388K
Rosemead, CA 91770

Re: Data Request for the SCE Four Corners Generating Station Project

Mr Stevenson:

The California Public Utilities Commission (CPUC) prepared a Draft Initial Study/Negative Declaration (IS/ND) for the SCE Four Corners Generating Station Project that was circulated for public review from September 27, 2011 to October 27, 2011. Several comments were received during the public review period. The CPUC is currently responding to the comments; however, some additional questions have arisen that have prompted this data request to SCE.

Please provide responses to the data requests below by Friday, January 6, 2012.

1. Please provide documentation regarding the determination as to whether the capital improvement projects performed by SCE, APS (or any owners of the Four Corners Generating Station) between 2007 and 2011 met the definition of "modification" in the federal New Source Review Rules and therefore required a permit from the EPA.

    a. If the improvements were not considered "modifications," please provide any correspondence with the EPA or the relevant air permitting agency regarding their concurrence with that determination.

    b. If the improvements were considered modifications, please provide copies of the permits obtained for those improvements.

2. Do the proposed capital improvement projects for 2012 in the application for sale of SCE's interest in Four Corners Generating Station meet the definition of "modification?"

a. If the improvements are not considered "modifications," please provide any correspondence with the EPA or the relevant air permitting agency regarding their concurrence with that determination.

b. If the projects included in the current application for capital improvements do meet the definition of "modification" in the federal New Source Review Rules, then please indicate whether SCE, APS or any other owner has already submitted an application for and/or obtained a permit for the proposed capital improvements. Please also indicate whether the application and permit are subject to the Greenhouse Gas (GHG) Tailoring Rule.

3. Please provide contact information for an appropriate contact at APS. The CPUC intends to inquire whether APS has stated (or is willing to state) definitively and in writing that it will be shutting down Units 1-3 at the Four Corners Generating Station, and whether a certain date has been established for the closure of these three units.

Thank you in advance for your timely assistance in addressing these data requests.

Please give me a call at 415-703-3221 if you have any questions.

Sincerely,

Andrew Barnsdale
Energy Division
Transmission and Environmental Permitting
California Public Utilities Commission

Cc: ALJ Hallie Yacknin
Nicholas Sher, Legal Division
Mary Jo Borak, Energy Division

Southern California Edison
Four Corners 851 Application A.10-11-010

DATA REQUEST SET A.10-11-010 Energy Division-SCE-001

To: ENERGY DIVISION
Prepared by: Sumner J. Koch
Title: Sr Atty
Dated: 12/21/2011

Question 01:

Please provide documentation regarding the determination as to whether the capital improvement projects performed by SCE, APS (or any owners of the Four Corners Generating Station) between 2007 and 2011 met the definition of "modification" in the federal New Source Review Rules and therefore required a permit from the EPA.

a. If the improvements were not considered "modifications," please provide any correspondence with the EPA or the relevant air permitting agency regarding their concurrence with that determination.

b. If the improvements were considered modifications, please provide copies of the permits obtained for those improvements.

Response to Question 01:

SCE, APS and the other Four Corners co-owners do not consider any of the referenced projects to be “major modifications” that would trigger New Source Review under the federal Clean Air Act (CAA) and its implementing regulations. The vast majority, if not all, of these projects are common in the utility industry to maintain safety, efficiency, and reliability, and are thus “routine maintenance, repair, and replacement” excluded from NSR review. None of these projects are of a type that would have resulted in an increase in actual, annual emissions. As SCE has also mentioned to CPUC staff:

1. <u>EPA Information Request</u>: In March 2009 the US EPA sent an Information Request to APS under CAA Section 114 (copy attached), requesting various information about the Four Corners plant, including information on essentially all capital projects at the plant from 1990 to 2009. Such information requests are typically used by EPA for purposes of investigating possible New Source Review violations. The information requested by EPA was voluminous, and APS responded to EPA over the course of mid-2009. To date, EPA has not followed up with any complaint, Notice of Violation, or any other enforcement action.

2. <u>Citizens lawsuit:</u> In October 2011, four environmental organizations (Sierra Club, Diné CARE, To' Nizhoni Ani, and National Parks Conservation Association) filed a lawsuit against the Four Corners co-owners under the citizens suit provision of the CAA, alleging that certain Four Corners plant projects in 1985-1986 and 2007-2011 constituted “major modifications”

triggering New Source Review. The complaint has not yet been served on APS, SCE or the other Four Corners co-owners, and the co-owners therefore have not yet filed a response, but the co-owners deny the allegations and intend to vigorously defend the lawsuit.

3. GHG Emissions Issue: These 2007-2011 projects, and the fact that they did not result in any GHG emissions increase, have also been the subject of SCE testimony and filings in SCE's Test Year 2012 General Rate Case. SCE's Rebuttal Testimony in that proceeding (SCE-17, Vol. 6, Part 2, pp. 21, 24) demonstrated that none of the 2007-2011 projects caused any material variation in the historical capacity factors of Units 4 and 5. In other words, none of the referenced projects caused Four Corners Units 4 and 5 to "run more" as compared to the historical baseline. In fact, the largest and most contested projects included those that allowed Units 4 and 5 to generate more megawatt output for the same amount of coal/steam input. To cite an example, the 2010 Unit 4 High Pressure Turbine Section Replacement project resulted in an "efficiency improvement [that] provide[d] a decrease in fuel consumption for the same level of power output." (SCE-02, Vol. 6, Part 2, pg, 25). Also in SCE's Rebuttal Testimony (SCE-17, Vol. 6, Part 2, Pages 28-33) it was established that none of the referenced projects caused – nor could they cause – Four Corners' Units 4 and 5 GHG emissions to increase. SCE's testimony is clear on this point, and is further supported by APS's 2005 pre-construction assessment of the turbine projects, which concluded that "[b]ecause the projects will improve efficiency and will not affect the availability or utilization of the units, there is no reasonable possibility that the projects will result in an annual emissions increase." (This is an APS Confidential document that was quoted in Exhibit SCE-17, Vol. 6, Part 3, Confidential Appendices, p. B-43). These points were further reinforced in SCE's Opening Brief at p. 30, our Reply Brief at pp. 28-29, and our Reply Brief on Update Issues at p. 6. Relevant excerpts of the testimony and briefing is attached.

Finally, Staff has inquired about the impact of these projects on the Units' "potential to emit." Under the NSR rules, a unit's potential to emit is the maximum amount of pollutant that a unit could emit "under its physical and operational *design*," that is, the maximum amount of a pollutant that a unit could emit if it were to run at full design capacity all the time, 365 days a year. *See* 40 C.F.R. § 52.21(b)(4) (emphasis added). NSR is triggered, however, by a significant increase in actual — not potential — emissions. *Id.* §§ 52.21(a)(2)((iv). In any event, neither the actual nor the potential emissions of the Units increased as a result of these projects.

6 attachments

FCPP Section 114 Request from EPA (03-25-09).pdf

SCE reply Brief Oct 2011 pg 25-29.pdf

SCE-02 direct testimony Nov 2010 pg 25.pdf

SCE opening brief Sept 2011 pg 28-30.pdf

SCE rebuttal testimony July 2011 pg 19-24.pdf

SCE reply brief on update issues Nov 2011 Pg. 6.pdf

Be chu

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

March 25, 2009

CERTIFIED MAIL: 7000 0520 0021 6108 1728
RETURN RECEIPT REQUESTED

Jack E. Davis
President and Chief Executive Officer
Arizona Public Service Company
400 North 5th Street
Phoenix, Arizona 85004-3902

RE: Information Request Pursuant to Section 114 of the Clean Air Act

Dear Mr. Davis:

The United States Environmental Protection Agency, Region 9 ("EPA") hereby requires Arizona Public Service Company ("APS") to provide certain information as part of an EPA investigation to determine the Clean Air Act ("CAA" or the "Act") compliance status of the coal-fired power plant known as the Four Corners Power Plant ("FCPP"), which is located on the Navajo Indian Reservation approximately 25 miles west of Farmington, New Mexico.

Pursuant to Section 114(a) of the CAA, 42 U.S.C. § 7414(a), the Administrator of EPA is authorized to require any person who owns and/or operates an emission source to establish and maintain records, make reports and provide such other information as he or she may reasonably require for the purposes of determining whether such person is in violation of any provision of the Act. In order for EPA to determine whether a violation has occurred, you are hereby required, pursuant to Section 114(a) of the CAA and this information request, to provide responses to the following requests for information regarding the FCPP. Please see Enclosure 1 for instructions and definitions.

1. For each coal-fired boiler at the FCPP, provide a list of all owners and operators, including all previous owners and operators since January 1, 1990, including the percentage ownership for each owner. For this same time period, describe any and all partnership agreements between these owners and operators concerning the FCPP. Describe the decision-making mechanisms in these agreements with regard to capital projects at the FCPP. Provide a copy of each such agreement.

2. For each coal-fired boiler at the FCPP, provide a list of all capital projects of greater than $100,000 for which physical construction commenced after January 1, 1990, to the present which provides:

   a. the work order number,

b. project description,

c. authorized expenditure,

d. actual expenditure,

e. date of approval,

f. project completion date and

g. return to commercial operation date.

3. Provide a copy of all capital appropriation requests for capital projects with actual or authorized total expenditures greater than $250,000 at the FCPP for the period of January 1, 1990, to the present. For each project, identify the date the coal-fired boiler returned to commercial operation following completion of the capital project or document that the project was never undertaken.

4. For each capital appropriation request identified in paragraph no. 3, provide:

a. a copy of the request with authorized expenditure, authorizing signatures and approval dates,

b. total project cost, including any cost incurred by APS and all other costs shared by other owners and operators of the coal-fired boiler,

c. project completion date,

d. the date the coal-fired boiler returned to commercial operation following completion of the capital project,

e. equipment specifications,

f. cost/benefit analyses,

g. all alternative options analyses,

h. all proposals, request for proposals and price quotations submitted by equipment suppliers or contractors,

i. a copy of all correspondence between APS and any contractor describing any changes in material type or design from the existing component(s) being replaced,

j. a copy of any emissions calculations performed before and after the capital project was completed,

k. any engineering analysis, performance test, or other related documents showing original as-built performance and performance for the period immediately prior to and immediately following completion of each capital project,

l. any evaluation and associated documentation conducted to verify pre- and post-completion performance of the capital project under any equipment vendor guarantee,

m. all work order and work request project completion reports,

n. all purchase orders and contracts entered into, and

o. whether the capital improvement was associated with a life extension project, capacity increase, efficiency enhancement or reliability improvement.

5. Provide a copy of all engineering analyses, correspondence, memoranda, telephone discussion summaries and any other communication, including but not limited to Board of Directors reports, meeting minutes, annual reports, and reports and/or applications to utility regulatory agencies such as the California Public Utilities Commission, the New Mexico Public Regulation Commission, and the Arizona Corporation Commission, that describe the benefits, provides justification for, or otherwise explains the nature, extent, cost and frequency of each capital project identified in paragraph 3. This request includes all communications both before and after the capital project was undertaken.

6. For the capital projects identified in paragraph 3, provide the Federal Energy Regulatory Commission ("FERC") Property Record Accounts 311, 312, 314 and 316. If your accounting practices differ from those outlined by FERC, provide information analogous to the FERC property records identified above along with any supporting information.

7. Provide the design specifications, as of January 1, 1990, for each coal-fired boiler at the FCPP as follows. Include all documentation and correspondence, including but not limited to engineering calculations and contract specifications used in setting the design values.

a. Steam flow rate, steam temperature and pressure,

b. Maximum hourly heat input capacity and an explanation of the assumptions made to determine this maximum heat capacity, which shall include, but not be limited to, the coal heat content (in Btu/lb) and the maximum hourly coal feed rate (in lbs/hr),

c. Maximum hourly coal feed rate (in lb/hr),

d. Gross hourly capacity (in Mw),

e. Net hourly capacity (in Mw),

f. Net heat rate (in Btu/Kw-hr), and

g. Design emission rates (in lbs/mmBtu and lbs/hr) for NO_x, SO_2, CO, PM, and PM_{10}.

8. Provide the information identified in subparagraphs a. through g. of paragraph 7 at peak and sustained steady state operation, for the one year period preceding and following all capital projects identified in paragraph 3 which were constructed at the FCPP. The information should include, but is not limited to, actual measurement data and any tests conducted to establish pre- and post-project coal-fired boiler performance.

9. From January 1990 to the present, provide the following for each coal-fired boiler at the FCPP for each calendar year. To the extent available, please provide in computer readable format such as an Excel spreadsheet or other accessible format:

a. capacity factor on a monthly and annual basis,

b. equivalent availability factor on a monthly and annual basis,

c. Operating hours on a monthly and annual basis,

d. coal consumption on a monthly and annual basis,

e. maximum hourly average and daily average coal feed rate (in lb/hr) for each month,

f. fuel quality (e.g., % sulfur, % ash, and heat content) on a monthly and annual basis,

g. total gross and net generation (in Mw-hr) on a monthly and annual basis,

h. heat input rate (in mmBtu/hr) on a monthly average and annual average basis,

i. maximum hourly average and daily average heat input rate (in mmBtu/hr) for each month,

j. heat rate (in Btu/Kw-hr) on a monthly average and annual average basis,

k. identify the top ten annual causes of forced outages and deratings by Mw-hr of lost generation,

l. lost generation during planned outages,

m. Generating Availability Data System ("GADS") reports in both hardcopy and electronic format (e.g. GADS-compatible ASCII format). This information should include for each outage at each coal-fired boiler, the:

   i. lost generation (in Mw-hr) as a result of forced, maintenance, or scheduled outages,

   ii. duration (in hrs) of all outages, deratings, and curtailments,

   iii. start date and time of outage,

   iv. end date and time of outage,

   v. North American Electric Reliability Corporation ("NERC") cause code,

   vi. event type,

   vii. event number,

   viii. for the year prior to the outage or derate, the net dependable capacity at the time of the outage or derate, and

   ix. forced, maintenance or scheduled outages, deratings and curtailments, caused by:

      (1) boiler related components,

      (2) turbine generator components,

      (3) pollution control performance,

      (4) balance of Station, and

      (5) miscellaneous

n. scheduled or planned boiler unit retirement dates,

o. all historical capability test results of each unit (in Mw), and

p. maximum hourly and daily average gross generation (in Mw) for each month.

10. For each outage identified and included in the annual GADS "top 10" report for each coal-fired boiler at the FCPP for the period January 1, 1990, to the present, provide:

a. a copy of the outage report, including the start and end dates and times, the nature or cause of the outage, and

b. any remedies taken to restore permanently lost, temporarily derated or curtailed capacity.

11. For each performance test conducted for the purpose of determining the operational rating of each coal-fired boiler at the at the FCPP, provide:

a. the day and hour of the capacity test with any relevant testing protocol specified by the power pool operator,

b. the standard operating procedure, or equivalent document, for the performance of the capacity tests. This would include the procedures, specifications, conditions, and other parameters under which the representativeness and accuracy of the tests are determined,

c. all results of capacity tests including the condition (e.g. valve wide open), steam flow and coal used,

d. the information requested in subparagraphs a. through c. of paragraph 11 for any other capacity tests not otherwise provided above, irrespective of whether required by rule or conducted for any other purpose including short tests, and

e. a description of any equipment limitations or other limiting factors that restricted capacity.

12. For all add-on SO_2 control technology utilized at the FCPP, and separately for each coal-fired boiler to the extent such information is available, provide the following information:

a. a summary of monthly SO_2 removal efficiencies from January 1, 1990, to the present, and

b. the maximum peak and sustained scrubber efficiency on a daily average and monthly average basis for each unit.

13. From January 2000 to the present, provide summary results of all complete or partial stack tests performed for PM and PM_{10} for each coal-fired boiler at the FCPP. If such data is available, include separately all test data concerning "back half" or condensible PM and PM_{10}.

14. If APS seeks to withhold any documents based on a claim of attorney-client communications privilege or the attorney work product doctrine in its response to this information request, provide a privilege log for each document containing the following information: (i) the date, author(s), every individual to whom the document was originally sent, every individual who subsequently acquired the document, the purpose for which the document was sent to or obtained by those individuals, and the employment titles of the authors and recipients; (ii) the subject matter of the document; (iii) the privilege claimed for the document and all facts supporting the claim of privilege; (iv) the primary purpose(s), including any business purposes, for which the document was made; (v) the question(s) in this information request that the document is responsive to; and (vi) all facts contained in the document that are responsive to a question in this information request.

EPA requires APS to fully respond to this information request no later than sixty (60) calendar days after your receipt of this letter. Please submit your response to this information request to:

Deborah Jordan
U.S. Environmental Protection Agency, Region 9
75 Hawthorne Street
San Francisco, California 94105
ATTN: Mark Sims (Air-5)

The response to this information request must be certified by a duly authorized officer or agent of APS by signing the enclosed Statement of Certification (see Enclosure 2) and returning it with the response. All information submitted in response to this information request must be certified as true, correct, accurate, and complete by an individual with sufficient knowledge and authority to make such representations on behalf of APS.

If you anticipate not being able to respond fully to this information request within the time period specified, you must submit a sworn declaration by a responsible corporate official within ten (10) calendar days after your receipt of this letter specifying what information will be provided within the time specified, describing what efforts have been/are being made to obtain other responsive information and providing a detailed schedule of when such other responsive information can be provided. Upon receipt and based upon such declaration, EPA may extend the time in which responsive information must be provided. Based upon such notification, EPA may modify the scope of documents required to be produced.

Please be advised that under Section 113(a) of the Act, failure to provide the information required by this letter may result in an Order requiring compliance, an Order assessing an administrative penalty, or a civil action for appropriate relief. In addition, Section 113(c) of the Act provides criminal penalties for knowingly making any false statements or omission in any response required under the Act. EPA may also seek criminal penalties from any person who knowingly alters, destroys, mutilates, conceals, covers up, falsifies, or makes a false entry in any record, document, or tangible object with the intent to impede, obstruct, or influence the investigation or proper administration of any matter within the jurisdiction of EPA or in relation to or contemplation of any such matter or case. See 18 U.S.C. § 1519 (2004). The information provided by you may be used by the United States in administrative, civil, or criminal proceedings.

You may, if you desire, assert a business confidentiality claim on behalf of APS covering part or all of the information provided to EPA in response to this letter. Any such claim to confidentiality must conform to the requirements set forth in 40 C.F.R. part 2, especially 40 C.F.R. § 2.203. You are advised that certain information may be made available to the public pursuant to 42 U.S.C. § 7414(c) and 40 C.F.R. § 2.301, notwithstanding a claim that such information is entitled to confidential treatment. If no claim of confidentiality is received with your reply, the information may be made available to the public without notice to APS.

The requirements of this letter are not subject to the Paperwork Reduction Act of 1980, 44 U.S.C. § 3501 *et seq.*

If you have any questions regarding this information request, please contact Mark Sims (415-972-3965) of my staff, or have your attorney contact Allan Zabel (415-972-3902) of our Office of Regional Counsel.

Sincerely,

Deborah Jordan
Director, Air Division

Enclosures: Instructions and Definitions
Statement of Certification

cc: Mr. Stephen B. Etsitty, Executive Director, Navajo EPA
Mr. David Saliba, Plant Manager, FCPP

ENCLOSURE 1

INSTRUCTIONS

1. Provide a separate narrative response to each numbered paragraph and subpart of a numbered paragraph set forth in this information request. To the extent that APS has no responsive information or documents for any particular request, this must be explicitly stated in the response.

2. Precede each answer with the number of the paragraph to which it corresponds and at the end of each answer identify the person(s) that provided information that was used or considered in responding to that paragraph, as well as each person that was consulted in the preparation of that response.

3. Indicate on each document produced in response to this information request, or in some other reasonable manner, the number of the paragraph to which it corresponds. To the extent that a document is responsive to more than one request, this must be so indicated and only one copy of the document need be provided. All documents produced shall be Bates stamped.

4. When a response is provided in the form of a number, specify the units of measure of the number in a precise manner.

5. Where documents or information necessary for a response are neither in your possession nor available to you, indicate in your response why such documents or information is not available or in your possession and identify any source that either possesses or is likely to possess such information.

DEFINITIONS

All terms used in this information request will have their ordinary meaning unless such terms are defined in the Act, 42 U.S.C. § 7401, C.F.R. Part 52, or other Clean Air Act implementing regulations.

1. The terms "document" and "documents" shall mean any object that records, stores, or presents information, and includes writings, memoranda, records, or information of any kind, formal or informal, whether wholly or partially handwritten or typed, whether in computer format, memory, or storage device, or in hardcopy, including any form or format of these. If in computer format or memory, each such document shall be provided in translation to a form useable and readable by EPA, with all necessary documentation and support. All documents in hard copy should also include attachments to or enclosures with any document.

2. The term "capital appropriation requests" shall mean the documents used by station personnel that serve the purpose of describing capital projects for equipment and process changes when seeking management approval for a planned expenditure at the station. These documents are also known as capital improvement requests, authorizations for expenditure, work order

records, or other similar names.

3. The term "coal-fired boiler" shall mean all equipment used for the purpose of generating electricity including but not limited to coal handling facilities, boilers, ductwork, stacks, turbines, generators, and all ancillary equipment.

4. The term "hr" shall mean one hour.

5. The term "lb" shall mean one pound in weight.

6. The term "Mw" shall mean a megawatt of electrical energy.

7. The term "Mw-hr" shall mean megawatt hours of electrical energy.

8. The term "Kw-hr" shall mean kilowatt hours of electrical energy.

9. The term "Btu" shall mean the British Thermal Unit of heat.

10. The term "mmBtu" shall mean one million British Thermal Units of heat.

11. The terms "you" or "APS" shall mean the addressee of this information request, the addressee's officers, partners, managers, employees, contractors, trustees, successors, predecessors, assigns, and agents.

12. The term "information request" shall mean this letter and all enclosures.

13. The term "capacity factor" shall mean the percentage of total gross megawatts hours produced by the coal-fired boiler compared to the total amount of megawatts hours that could have been produced at 100% equivalent availability factor for a given time period. Specify the maximum gross megawatt value used in calculating capacity factor.

14. The term "equivalent availability factor" shall mean the percentage of gross megawatt hours the coal-fired boiler was actually mechanically available to generate electricity in any amount compared to the maximum amount of megawatt hours the unit would theoretically be able to produce for a given time period without any mechanical restrictions (forced outage or deratings) to the existing coal-fired boiler. Specify the maximum gross megawatt value used in calculating equivalent availability factor.

15. The term "net dependable capacity" shall mean the maximum capacity a coal-fired boiler can sustain over a specified period of time, adjusted for seasonal limitations and less the coal-fired boiler capacity utilized for that coal-fired boiler's station service and/or auxiliaries.

ENCLOSURE 2

STATEMENT OF CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the statements and information submitted in the enclosed documents, including all attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, correct, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information, or omitting required statements and information, including the possibility of fine or imprisonment.

Date: ______________________________

Signature: ______________________________

Name (printed or typed): ______________________________

Title: ______________________________

This expenditure includes replacement and upgrade of the high-pressure steam path, including new turbine inner shells and a new high efficiency rotor with increased number of stages and smaller wheel diameters to optimize the steam path. Also included is a new solid particle erosion (SPE) resistant single flow nozzle, replacement of the mechanical-hydraulic control system, and control valves modification to allow full-arc steam admission. Full-arc admission reduces the level of thermal fatigue the turbine experiences on start-up, which should help reduce future overhaul costs later in the turbine's life. APS forecasts that the existing HP Turbine outer shell can be refurbished and reused, reducing cost.

This expenditure will also replace turbine controls system field devices and mechanical linkages which currently measure the position of the control valves and steam temperatures and pressures. The controls system components currently being utilized are old (1960's design) and have reached the end of their useful lives. Maintaining these systems to a high level of reliability has proven to be difficult and labor intensive. Start-ups have been negatively affected by erroneous indications of these field devices, resulting in start-up delays and unit trips. Replacement of these devices will improve future start-up performance.

Since the time Four Corners was constructed, the technology and design of these machines has advanced. These advancements result in improved machine efficiency. This efficiency improvement provides a decrease in fuel consumption for the same level of power output. This project helps assure the continued safe and reliable operation of the turbine. This expenditure will be implemented during the 2010 Unit 4 Major Overhaul. This project yields a Benefit to Cost Ratio of 6.0.

8. <u>Pedant Reheater & Outlet Header Replacement Unit 4</u>

This $16.619 million expenditure (of which SCE's share is $7.977 million) replaces the Unit 4 pendant reheater tube assemblies and the associated inlet and outlet steam headers. This project will be done during the 2010 overhaul. The reheater is an assembly of tube bundles within the boiler setting that transfers thermal energy from hot combustion gasses exiting the furnace to steam coming from the outlet of the HP turbine. The steam enters the reheater at a temperature between 600 and 700 degrees and exits at approximately 1,000 degrees. The steam is then introduced into the intermediate pressure turbine (IP Turbine) for expansion and release of its energy in the production of electrical power.

focuses on reliability projects that involve the replacement of the following four types of equipment items: Boiler Tube Sections, High Pressure Feedwater Heaters, Generator Step-Up Transformers, and High Pressure Turbine Component Sections. Sierra Club argues that these capital projects make plant "life extension" more likely, that the projects increase reliability rather than sustaining it at historic levels, that lower cost options were available in lieu of SCE's capital expenditures, that SCE's economic evaluations are flawed, and that the projects somehow increase the plant's "output."[158]

None of these arguments have merit. SCE's direct and rebuttal testimony conclusively demonstrated that the projects are not "life-extending," were necessary to retain plant reliability, are the most economic option available, remain economic over a wide range of assumed replacement power costs, and do not increase the generator nameplate MW rating of Unit 4 or Unit 5 or increase generating unit capacity in any manner contrary to the apparent objectives of the EPS or D.10-10-016.[159] More broadly, SCE's rebuttal testimony conclusively demonstrated that all of the projects completed during 2007 through 2011 (including the remaining 2011 projects still underway at this time) comply with D.10-10-016, and that the planned 2012-2014 capital projects do not otherwise violate the EPS. The Four Corners capital projects that are at issue in this proceeding are necessary, reasonable and fully compliant with the Commission's directives, and should be approved.[160]

The capital projects at issue in this proceeding are not "life-extending." The Four Corners co-ownership agreements had original 50-year terms (through 2016). All actions taken by SCE, including capital spending decisions, have been entirely consistent with this original 50-year life-expectancy.[161] Simply put, as SCE has consistently explained, the projects are not "life-extending" because SCE does not plan to participate in Four Corners beyond the expiration of the current co-ownership agreements,

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[158] Exhibit SCE-01, pp. 7-9.

[159] *See generally*, Exhibits SCE-02, Vol. 6, Part 1, and SCE-17, Vol. 6, Part 2.

[160] Although the balance of the material in this section of SCE's brief addresses Sierra Club's arguments, TURN also proposes to adjust SCE's 2010 Four Corners capital expenditure forecast downward by $8.333 million (SCE share, nominal, work order level), by adopting SCE's actual recorded 2010 expenditures of $21.513 million rather than SCE's forecast 2010 expenditures of $29.846 million. *See* Exhibit-TURN-03, pp. 24-25. SCE has continued to work with plant operator APS and the other plant co-owners to reduce and postpone capital expenditures to the extent practical. Accordingly, SCE can agree to a partial $5.936 million reduction to its TY forecast. However, the balance of $2.397 million still needs to be included because that portion of the 2010 under-run was due to the postponement of a single project from 2010 to 2011. That $2.397 million project is the environmentally-needed expansion of the fly ash disposal area, specifically, the Dry Fly Ash Disposal Area Phase 2, Units 4 & 5 project that had been forecast for 2010. The project is now in progress and is expected to be completed in 2011. SCE has updated its 2010 capital forecast to reflect the reduction of $5.936 million and its 2011 capital forecast to reflect the increase of $2.397 million. *See* Exhibit SCE-25, Vol. 1.

[161] Exhibit SCE-17, Vol. 6, Part 2, p. 13.

and the projects make financial sense within the term of those agreements.[162] Nothing in the EPS prohibits SCE from making routine, normal capital expenditures to keep Four Corners running safely and reliably as it seeks an exit from the plant.[163] To be clear, that is what these projects are: routine, normal, reliability-driven capital expenditures designed to maintain historical levels of reliability.[164]

The reliability-based Four Corners capital projects are necessary to keep Four Corners operating at approximately historical levels of reliability.[165] Funding projects that keep Four Corners operating reliably is important to SCE and its ratepayers, because, among other reasons, the Commission reviews Four Corners outages for reasonableness in SCE's annual ERAA proceeding.[166] Four Corners is one of SCE's lowest-cost generating resources, and when SCE purchases replacement power during Four Corners outages, that power almost always has a higher cost than Four Corners generation.[167] SCE is responsible for funding the *overall* operation of Four Corners in the most cost-effective manner practical for our customers, and not to "run it to failure" as the Sierra Club's proposals would have us do by minimizing capital costs.[168] Nothing in the EPS requires a different result.[169]

SCE also demonstrated that the capital projects at issue are economic, including the boiler tube replacement projects, the feedwater heater replacement projects, and the high-turbine component sections replacements Sierra Club complains about.[170] SCE further demonstrated that simply "repairing" worn-out equipment instead of replacing it was neither economic nor feasible.[171] In addition, contrary to Sierra Club's arguments about SCE's assumptions of replacement power costs, the replacement projects are cost-effective assuming SCE's original forecast replacement power costs *and* assuming drastically lower future replacement power costs.[172]

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162 Exhibit SCE-17, Vol. 6, Part 2, pp. 13-14.

163 *See also* D.04-07-022 at pp. 66-67 (Regarding SCE's Mohave coal plant, "the evidence does not support ORA's conclusion that SCE's planned capital spending should be limited to the bare minimum needed for regulatory requirements, environmental protection and safety" but rather should include capital projects so as to not "unduly impact production reliability.").

164 Exhibit SCE-17, Vol. 6, Part 2, pp. 19-24.

165 Exhibit SCE-17, Vol. 6, Part 2, pp. 19-24.

166 Exhibit SCE-17, Vol. 6, Part 2, p. 8.

167 Exhibit SCE-17, Vol. 6 (Part 2), p. 8.

168 Sierra Club's argument that SCE (presumably through plant operator APS) should have run the worn-out GSU transformers to failure instead of replacing them is particularly unconvincing given the irrefutable safety and economic implications of that course of action. *See* Exhibit SCE-17, Vol. 6 (Part 2), pp. 42-45.

169 D.10-10-016 at p. 16 ("Nothing in [the EPS] suggests a desire to reduce reliability by requiring the repair of old parts, rather than replacement.").

170 Exhibit SCE-17, Vol. 6, Part 2, pp. 34-41; 46-51.

171 Exhibit SCE-17, Vol. 6, Part 2, pp. 52-55.

172 Exhibit SCE-17, Vol. 6, Part 2, 56-58.

Finally, none of the capital projects at issue in this GRC increase the generator nameplate rated MW capacity of Units 4 & 5, the only increase in "capacity" prohibited by the EPS.[173] But Sierra Club argues that certain completed capital projects might have increased Four Corners' "actual capacities" in other ways.[174] To begin, SCE has been granted an exemption from the EPS in D.10-10-016 for the completed capital projects Sierra Club complains about, making Sierra Club's "capacity" arguments entirely irrelevant. But even for those future projects that do not fall under the exemption as currently articulated, SCE has demonstrated conclusively that they will not change the generators' nameplate rated capacity, nor are they likely to change the plant capacity in any discernable manner that would increase greenhouse gas emissions.[175] Sierra Club's attempts during cross examination of SCE witness Ware to show that the high pressure turbine component replacement projects somehow increased the plant's greenhouse gas emissions are similarly unavailing. Even if such an inquiry was relevant under the EPS or otherwise in this GRC (which it is clearly not), all of Sierra Club's questions focused on *ex ante* projected design performance of the turbine upgrades, not *ex post* actual performance of the units after the upgrade.[176] Moreover, SCE has demonstrated that the turbine component replacement projects increased megawatt *output* by using the same amount of fuel and steam flow *inputs*; i.e., SCE's customers got *more* energy in exchange for the *same* level of greenhouse gas emissions.[177]

Finally, Sierra Club's arguments have very little (if anything) to do with the relevant issues in this rate case, and Sierra Club's very involvement in this proceeding appears to be motivated by obtaining discovery for unrelated proceedings and litigation. ALJ Darling recognized this when Sierra Club filed a motion to compel environmental monitoring documents allegedly related to certain coal ash impoundment capital projects being reviewed in this proceeding. The ALJ rejected Sierra Club's tortured logic regarding the alleged relevance of those documents, ruling that "[t]he requested information, while perhaps relevant to SCE's Section 851 application or other proceedings, was not shown to be relevant to the reasonableness of the capital expenditures forecast in 2010 and 2011."[178] In addition, on September 2, 2011, the Sierra Club served the Four Corners co-owners with a Notice of

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173 SCE-02, Vol. 6, Part 3. *See also* D.07-01-039 at p. 53 ("[W]e will define 'new ownership investments' to include any investment that … results in a net increase in the existing rated capacity of that powerplant. 'Rated capacity' refers to the plant's maximum rated output under specific conditions designated by the manufacturer and usually indicated on a nameplate physically attached to the generator.").

174 Exhibit SC-01, p. 16.

175 Exhibit SCE-17, Vol. 6, Part 2, pp. 30-33.

176 SCE, Ware, Tr. 13/1837-1851.

177 Exhibit SCE-2, Vol. 6, Part 1, p. 6; Exhibit SCE-17, Vol. 6, Part 2, p. 28.

178 ALJ Darling's 8/23/11 Email Ruling Denying Sierra Club Motion to Compel.

VI.

SIERRA CLUB'S CLAIM THAT THESE PROJECTS ARE NOT NECESSARY BECAUSE THEY IMPROVE PLANT RELIABILITY, RATHER THAN SUSTAIN IT, IS DEMONSTRABLY FALSE

Many of the projects at issue in this proceeding have already been completed, some as long as ago as 2007. Projects forecast for the remainder of 2011 and 2012, and for 2013-2014 should SCE still be a participant, are similar to those completed during 2007-2010. In turn, these 2007-2014 projects are similar to capital projects routinely completed at the plant during the many years leading up to 2007, and to those approved by the Commission in SCE's 2009 GRC and completed during 2007 through 2009. Replacement of worn out coal piping, fatigued turbine blades, aging transformers, degraded boiler tube panel sections, corroded and eroded heat exchangers and air preheater baskets, obsolete control systems where repair parts are no longer available, and so on, are routine at power plants such as Four Corners. For example, in 2006, the year which immediately precedes the start of the capital expenditures at issue in this proceeding, SCE recorded $9.012 million of capital expenditures (SCE Share, nominal, work order level).

As SCE explained in direct testimony, capital spending normally peaks in the year before (i.e., for replacement equipment procurement), and in the year during routine major overhauls (i.e., for replacement equipment installation). Routine major overhauls provide the several-week-long outage required for many equipment replacement installations. In order to minimize total outage duration over the life of the plant, routine major overhauls are typically only conducted every six years on each unit, and were most recently conducted in 2002 (Unit 5), 2004 (Unit 4), 2008 (Unit 5) and 2010 (Unit 4).

While such routine capital spending might appear large in absolute terms, it is only one component of the overall cost to operate large coal-fired generating units, such as Units 4&5. For example, SCE's share of coal fuel for these two units was approximately $89 million and $75 million in 2009 and 2010, respectively. Similarly, our 2012 Test Year O&M forecast is approximately $44 million (SCE Share, $2009). As explained earlier, the monetary value of the power output of Units 4&5 is also very large, exceeding $1 million per day, even assuming Sierra Club's figure of $35 per MWH.[23]

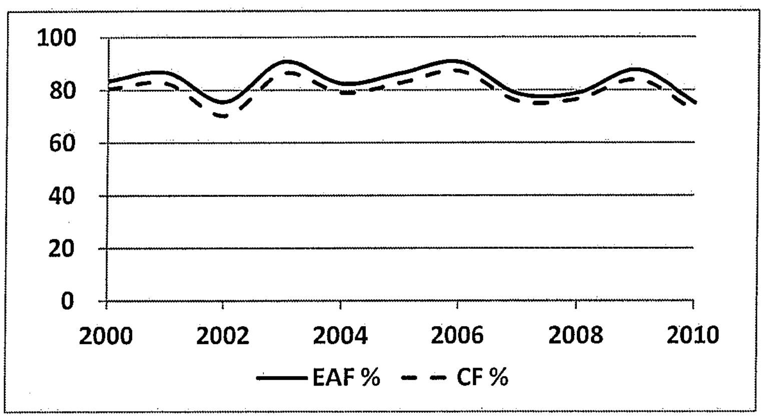
[23] 750 MW x 2 Units x 24 Hrs x $35/MWH = $1.260 million.

In spite of this history, Sierra Club argues that the capital expenditures at issue in this proceeding go beyond those needed to sustain unit reliability at historic levels, and summarizes their belief as follows:

> In fact, it is my experience that all these reliability-focused projects are not at all necessary just to maintain historical reliability, or even to prevent large decreases in reliability. Instead, they will tend to extend the life of the plant by *increasing* the overall reliability of a unit ....[24]

Sierra Club's claim in demonstrably false. As shown in Figure VI-1 below, Units 4 and 5 have already operated at relatively high reliability (i.e., Equivalent Availability Factor) and Capacity Factor for many years. As a practical matter, there simply is not much room for further improvement, and certainly not by continuing to maintain the plant in like fashion to what has been done in the past.

Figure VI-1
Four Corners Units 4&5 Combined EAF and CF



Capacity Factor (CF) is the percentage of actual MWH generation each year compared to the theoretical maximum generation possible if the generating units were to operate at its full rated capacity 24 hours per day, 365 days per year. Equivalent Availability Factor (EAF) is the percentage of time that the units are available for full rated generation operations, whether or not they are actually dispatched to full rated load when available to do so. The figure above provides the recorded Units 4&5, combined, EAF and CF for 2000 through 2010.[25] As shown, CF is approximately equal to EAF because Units 4&5 are very economic and therefore are typically operated at full load when available to do so.

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[24] Testimony of Robert Koppe on behalf of Sierra Club, p. 8.

[25] Capacity Factor was computed by dividing average recorded net MW output by the current approximate net output of 770 MW for each unit, when operating at full load. This provides a consistent basis to allow a direct comparison of all 11

(*Continued*)

As shown, during 2000 through 2010, Units 4 and 5 (combined) annual recorded EAF has ranged from approximately 75% to 91%, and averaged approximately 83%. It is not feasible for a generating unit to sustain a 100% EAF, because the unit must periodically be removed from service for maintenance. According to the North American Electric Reliability Corporation (NERC) Generation Availability Data & Statistics (GADS) data base, the average EAF achieved by coal-fired power plants over the past 5 years is approximately 84%. At 83%, the average EAF performance of Units 4 and 5 over the past 11 years is within one percent this North American average.[26]

Figure VI-1 also shows that Unit 4 and 5 EAF and CF (i.e., annual generation output) have been relatively flat over the past 11 years. The dips and peaks in CF and EAF primarily reflect the timing of major outages. These major outages include the routine major overhauls discussed above, as well as unplanned turbine repair outages lasting several weeks experienced in 2007 on both units due to turbine blade failures. These major outages explain why the EAFs recorded in 2002, 2004, 2007, 2008 and 2010 are all lower than all of the EAFs recorded in 2000, 2001, 2003, 2005, 2006 and 2009.

Figure VI-1 shows no discernable trend to support Sierra Club's allegation that 2007-2014 capital expenditures at issue in this proceeding have caused, or will cause, reliability to increase, rather than to be sustained at recent historic levels. In fact, the EAF recorded during 2007-2010, at approximately 80%, is actually lower than that recorded during 2000-2006 at approximately 85%. The EAF recorded to date through May 2011 (the most recent month of available statistics) shows no evidence of appreciable changes in EAF performance, with a 2011 year-to-date EAF of approximately 80.8%, which is slightly below than the 2000-2010 average of approximately 83%. The 2011 data also does not show any evidence of appreciable changes in CF performance, with a 2011 year-to-date CF of approximately 73.8%, which is below than the 2000-2010 average of approximately 82.1%.

Sierra Club does not specify exactly *when* it expects this surge of improved reliability to occur, nor does it list exactly *which* projects it expects will cause it. Based on 2010 and 2011 year-to-date reliability statistics, it certainly does not appear to be those projects already completed through 2010 that are at issue in this proceeding. These completed projects include approximately $50 million (SCE Share)

Continued from the previous page

years of historic data. Equivalent Availability Factor is computed based on hours of availability as compared to 8,760 hours in each year (or 8,784 hours in leap years), and therefore does not rely on a specific unit MW rating.

26 Based on the most recent, comparable industry-wide GADS data currently available: "Fossil - Coal Primary, All MW Sizes, 2005-2009," This data is provided in our supporting Appendices.

of projects that entered service in 2010 (mostly associated with the Unit 4 major overhaul), and approximately $9 million of projects that entered service during 2007-2009 that are being reviewed pursuant to D.10-10-016.[27]

Nor is it in any way likely that plant reliability will surge as a result of capital spending anytime during 2011 or 2012, given that significantly fewer projects will be completed during 2011 and 2012 as compared to those completed during 2007-2010. Our 2010-2014 Sale case capital expenditure forecast of approximately $130 million includes only approximately $12 million that is forecast to record during 2011 and 2012.

Our Sale case forecast includes approximately $62 million in 2013-2014, mostly associated with the forecast 2014 Unit 5 overhaul. The reliability impacts of most of those projects will not occur until after that 2014 overhaul is completed. However, as these 2013-2014 forecast projects are very similar to those completed during 2007-2010 and in prior years, SCE does not believe that these projects will cause plant reliability during 2014 through 2016 to surge above 2000-2010 levels.

As explained in Chapter III, SCE did not include any of the $32.686 million of forecast 2014 Unit 5 overhaul capital projects in our Plant Decommission case. SCE assumes that is the plant is to cease operation by mid-2016, it *might* be more cost effective to cancel many (or perhaps even all) of these 2014 overhaul projects and incur reduced reliability, and we assume this in our Decommission case forecast. However, as explained in our direct testimony, we include the 2014 Unit 5 overhaul projects in our Sale case because we do not yet know exactly when the proposed sale will close, or if it might terminate for other reasons.[28] If the proposed sale is not successfully consummated, the best option for SCE customers *might* be to continue to maintain the plant (including by performing the 2014 overhaul) while seeking another buyer for SCE's share, and we assume this in our Sale case forecast. The exact decision regarding these 2014 projects would depend on the actual circumstances encountered during 2012 and 2013.

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[27] SCE's 2012 GRC does not include $50.866 million of projects that entered service during 2007-2009 that were already approved in SCE's 2009 GRC (SCE direct testimony, Part 3, p. 12). SCE's 2012 GRC forecast includes $25.792 million (SCE direct testimony, Part 3, p. 1) of expenditures that recorded prior to 2010 for projects entering service during 2010-2014. Most of these pre-2010 recorded expenditures were for projects that entered service in 2010. The $50 million (SCE Share) estimate for 2010 projects is based on the total of these pre-2010 recorded expenditures for work in progress, plus SCE's 2010 forecast expenditures, minus the 2010 downward adjustment recommended by TURN as modified by SCE in Chapter II.

[28] SCE direct testimony, Exhibit SCE-2, Vol. 6, Part 3, Chapter XXII.

Like all GRCs, our 2012-2014 expenditures are a *forecast*. It is not possible to perfectly predict the rate at which the 2014 overhaul equipment replacements in our forecast will continue to degrade between now and the overhaul. If those items fail or demonstrate an increased risk of failure prior to the 2014 overhaul, and SCE is still a participant, it might well be more economic to replace them rather than to defer them. It is also not possible to identify exactly what other equipment replacement needs might arise, such as because of sudden catastrophic failure, that are not currently foreseen, although history indicates that such needs routinely arise. We believe our 2012-2014 expenditure forecast is a reasonable basis for 2012 GRC ratemaking, and demonstrates the likely projects and costs that will be incurred as SCE works to conclude the proposed sale in October 2012, or should SCE's participation beyond that point continue due to sale closure delays or other reasons.

Sierra Club's arguments concerning the reliability impacts of these projects also ignores that other factors, besides capital spending, can affect plant reliability. These include maintaining a cost effective balance between break down repairs and preventative repairs, and the training and qualifications of operations and maintenance personnel. Also, if one uses too narrow of a timeframe to measure reliability, one can obtain misleading results. The frequency of outages is often somewhat random rather than being evenly spread every month, or even every year. The overall reliability trend might be different when viewed from a wider timeframe perspective as compared to a more narrow perspective.

Fundamentally, Sierra Club ignores that while a capital expenditure to replace a degraded equipment item avoids increasing numbers of outages that would otherwise be caused by *that* equipment item, the plant is constructed of *hundreds* of such equipment items that can cause outages and these equipment items degrade at different rates. As one item is replaced, a different item then invariably arises that needs replacement.

Four Corners reliability-related capital spending is simply a part of the plant's overall maintenance process. Equipment items that wear out are replaced; i.e., partially replaced where practical, and completely replaced where more cost effective to do so. If these equipment replacements are being performed at a rate that essentially matches the rate at which these hundreds of equipment items are wearing out, then the *overall* plant reliability levels should *not* be expected to significantly change either up or down. Sierra Club's arguments that the capital spending at issue here will increase reliability ignores this simple principle, and more importantly, ignores actual plant historical reliability data, and should be rejected.

For many years, the reliability of Units 4 and 5 has been relatively high, and has been consistent with other coal plants. Their average availability since 2000 is already within one percent of the North American average for coal power plants. It makes no sense to conclude that planned and completed 2007-2012 routine expenditures, that are like-kind with numerous expenditures made in the past, have caused or will cause Units 4 and 5 to materially exceed the average EAF recorded by similar coal power plants across North America. Nor does it make sense to conclude that the similar capital expenditures forecast for 2012-2014, most of which are for the planned 2014 overhaul and which SCE has not included in the Plant Decommission capital expenditure cost forecast, would cause a material increase in reliability should SCE still be a plant participant during those years.

2011" and to "propose a course of action in its 2012 GRC prior to any final determination on rate recovery… ."[135]

It is clear that the Commission's different standard for the treatment of capital expenditures starting in 2012 as expressed in D.10-10-016 was motivated by the uncertainty regarding the viability of SCE's continued ownership in Four Corners, and driven by questions regarding the costs to SCE and its ratepayers of continued ownership beyond 2011. After all, "the primary objective of [the] EPS is to reduce California's [ratepayers'] exposure to the compliance costs associated with future GHG emissions (state and federal)."[136] Put another way: "If [California utilities] enter into long-term commitments with high-GHG emitting baseload plants during this transition, California ratepayers will be exposed to the high cost of retrofits (or potentially the need to purchase expensive offsets) under future emission control regulations."[137] SCE has now conducted and submitted the study ordered by the Commission,[138] addressed the Commission's concerns regarding compliance costs with GHG emissions and retrofits by entering into the proposed sale agreement and otherwise committing to not renewing its ownership interests beyond 2016, and accordingly "proposes [as] a course of action" that the Commission grant SCE an EPS exemption for post-2011 Four Corners capital expenditures.[139]

Sierra Club's argument that 2012-2014 capital projects should not be authorized warrants rejection.[140] While SCE is committed to not renewing our ownership interests, it does not mean that SCE can allow plant reliability to drastically degrade prior to 2016, in a manner that would be uneconomic for SCE customers. As Sierra Club notes, SCE provided capital forecasts for both a Sale Case and a 2016 Decommission Case, and SCE's Decommissioning Case capital expenditure forecast *assumes* that routine capital projects planned for the 2014 plant overhaul would be canceled and that a small reduction in reliability would be acceptable.[141] However, SCE also explained that this is simply an assumption, and that the projects forecast for the full overhaul are economic.[142]

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[135] D.10-10-016, pp. 19-20.

[136] D.07-01-039, p. 32.

[137] D.07-01-039, p. 3.

[138] *See* Exhibit SCE-02, Vol. 6, Part 3, pp. 26-31.

[139] As noted in our Opening Brief, even if the Commission declines to grant such an exemption, SCE's proposed post-2011 capital projects are not prohibited by the EPS. Exhibit SCE-06, Vol. 6, Part 3, pp. 36-41; *see also* Exhibit SCE-17, Vol. 6, Part 2.

[140] Sierra Club Opening Brief, pp. 10-11.

[141] *See* Exhibit SCE-02, Vol. 6, Part 1, pp. 24-25 and Exhibit SCE-02, Vol. 6, Part 2, pp. 6-8. As explained therein, the Sale Case assumes that the sale agreement requires maintaining the plant consistent with historic practices, including the completion of a full 2014 routine major overhaul. This assumption was finalized prior to concluding the sale agreement

(Continued)

As we explained, we also assumed that, for the Decommissioning case, an abbreviated overhaul (in lieu of a full overhaul) would be required to assure an acceptable level of reliability until the plant is shut down for decommissioning.[143] It is almost certain that at least some of the projects planned for the full 2014 overhaul would still be needed to assure reliable operation, even if only an abbreviated overhaul is conducted. However, as the overhaul is still well over two years away, it is difficult at this time to positively determine which projects would be needed and which could be canceled. As with all GRC capital expenditure forecasts, the Four Corners 2012-2014 forecasts for both the Sale and Decommission cases will require revision if and when plant circumstances warrant. Nevertheless, it remains in SCE's customers' best interests to allow SCE to continue to make necessary capital expenditures during 2012-2014 to assure the economic and reliable operation of the plant, even while SCE works diligently to conclude the proposed sale to APS; or if the sale does not close, to seek a replacement sale with another buyer or to participate in the plant until the current ownership term expires.

4.2.2.3 Sierra Club's Claims Regarding "Capacity Increases" Are Belied By Precedent And The Record

In addition to "life-extending" capital projects, the EPS generally prohibits those that cause "capacity increases." Sierra Club complains that "nameplate capacity has no practical relevance to the capacity and emissions increases caused by [Four Corners] projects" and urges the Commission to find that certain capital projects are EPS-non-compliant because they allegedly increased Four Corners' "actual capacity."[144] Sierra Club is wrong for at least three independent reasons.

Continued from the previous page

with APS, but is consistent with the APS sale agreement. The sale agreement also requires APS to reimburse SCE, upon the successful close of the sale, for capital expenditures approved by the co-owners during routine annual budgeting for 2012, which is currently underway. The sale is targeted to close in October 2012. In the separate Four Corners Sale Application (A.10-11-010), SCE has proposed to the Commission to credit the net sale proceeds to customer rates.

142 *See* Exhibit SCE-02, Vol. 6, Part 2, pp. 6-8 and Exhibit SCE-02, Vol. 6, Part 3, pp. 38-39. As explained therein, for purposes of project forecasting and economic analysis, for certain projects SCE assumed a plant life and a project economic life of up to 2021 (*i.e.*, a life expectancy of 2016 plus up to 5 years of "life extension" allowed by the EPS). This was necessary to ascertain in what year the project provides full "pay back" and to forecast SCE capital expenditures for continued ownership as required by D.10-10-016. The economic analyses determined that all projects in this GRC that cost more than $1 million provide pay back by 2015 year end or sooner, and all but one project that cost less than $1 million provide pay back by 2016 year end or sooner, using SCE's base assumptions on replacement power costs.

143 *See* Exhibit SCE-02, Vol. 6, Part 1, pp. 24-25 and Exhibit SCE-02, Vol. 6, Part 2, pp. 6-8.

144 Sierra Club Opening Brief, p. 13.

First, while that articulation of "capacity increase" may be Sierra Club's ***preferred*** legal standard, it is not the ***actual*** legal standard. The Commission has made clear that prohibited capacity increases are those that change the capacity of the unit as defined by the generator nameplate.[145] That is settled law, and if Sierra Club does not like it, they should have participated in the proceeding five years ago in which it became settled law.[146] It is undisputed that SCE has not implemented capital projects at Four Corners that necessitate a changing of the generators' nameplate capacities.[147]

Second, Sierra Club confuses relevant time periods and capital projects. One of the headings in Sierra Club's Opening Brief states that "SCE's ***proposed*** investments increase the capacity of Four Corners."[148] But the sub-heading indicates that the projects Sierra Club complains about were constructed in the past: "The turbine upgrade projects increas***ed*** the capacity of Four Corners."[149] This is more than a clumsy syntax error. Sierra Club claims that the high pressure turbine component replacement projects for Units 4 and 5 increased capacity. But those projects were completed in 2010 and 2008, respectively. Of course, because the Commission granted SCE an ***exemption*** under the EPS for pre-2011 capital projects, it is irrelevant whether or not those projects increased "capacity," whether measured by the correct legal standard or Sierra Club's invented one.

Third, even if "actual capacity" were the correct standard (which it is not), SCE has put forth evidence demonstrating that the turbine projects Sierra Club complains about have not and indeed cannot lead to increased GHG emissions from the plant.[150] Sierra Club levels the serious accusation that SCE "misleads the Commission and the public by claiming that this higher capacity represents nothing more than increased efficiency" and charges SCE with "willful ignorance."[151] To the contrary, SCE's testimony, both written and oral, was completely truthful. If any party is trying to mislead the Commission, it is Sierra Club, with their selective citations to the record and false analysis of the turbine projects' actual and potential effects on greenhouse gas emissions.

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[145] D.07-01-039, p. 53.

[146] The nameplate capacity standard as defined the Commission also makes good sense. Generator nameplate is not simply a "theoretical" number, as claimed by Sierra Club. It is the generator manufacturer's design capacity for the generator, it is a widely-used capacity benchmark used throughout the industry, and it is an objective, bright-line standard. Exhibit SCE-17, Vol. 6, Part 2, p. 30.

[147] Exhibit SCE-17, Vol. 6, Part 2, p. 30.

[148] Sierra Club Opening Brief, p. 13 (emphasis added).

[149] Sierra Club Opening Brief, p. 13 (emphasis added).

[150] Exhibit SCE-17, Vol. 6, Part 2, pp. 29-33.

[151] Sierra Club Opening Brief, pp. 14, 16.

As we have noted, the 2008 and 2010 turbine component replacement projects did not lead to an ***actual*** increase in greenhouse gas emissions. SCE presented ***actual*** greenhouse emissions data for the plant, which shows that greenhouse gases have not discernibly increased as a result of the turbine projects or any other projects completed during 2000-2010.[152] SCE also explained that there is no reason to believe that the projects forecast for 2011-2014 will increase GHG levels in the future, because these projects are similar to projects completed during 2000-2010.[153]

In addition, these projects do not even have the ***potential*** of increasing greenhouse gas emissions. Sierra Club grossly misconstrues SCE witness Ware's testimony during hearings regarding the potential effects of the turbine projects on greenhouse gas emissions. Sierra Club confuses and conflates two separate and distinct operating parameters: (1) ***steam*** (or heat) input to the turbine (which the 2008 and 2010 projects affected), and (2) ***coal*** combustion rate (which they did not). The former measures steam heat input (*i.e.*, steam flow) to the turbine, which is *not* the same thing as the amount of coal input to, and combusted by, the boiler. As Sierra Club notes, Mr. Ware affirmed that "greenhouse gas emission rate is directly related to its rate of ***coal combustion*** … ."[154] But then Sierra Club asked Mr. Ware a series of questions regarding ***turbine heat*** input design data. None of the design data diagrams used by Sierra Club involved coal input; all of them instead concerned turbine heat input.[155]

Sierra Club's assumption that greenhouse gas emissions levels can be determined by analyzing steam turbine heat input design data instead of boiler coal input rate data is erroneous. In fact, the 2008 and 2010 turbine component replacement projects cannot logically have increased the plant's greenhouse gas emissions because they are unrelated to coal combustion. The maximum rate of coal combustion, both before and after the 2008 and 2010 projects, has been limited by boiler capacity and not by turbine capacity. The turbine projects in question had no effect on the maximum coal combustion rate of the boilers. Therefore, there would be no reason to use turbine heat input design data to compute potential increases in greenhouse gas emissions. As Mr. Ware clearly stated in his prepared testimony,

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[152] Sierra Club argues that since SCE only presented GHG emissions data through 2010, the emissions effect of the turbine projects cannot be ascertained. Sierra Club Brief Opening Brief at p. 17. However, as one of the turbine projects (Unit 5) was completed in 2008, the 2009 and 2010 GHG emissions data can certainly be used to gauge the effect of the identical 2008 and 2010 turbine projects. SCE also included the most recently available 2011 year-to-date capacity factor for Units 4&5 (capacity factor is the percentage-actual MWH generation level as compared to the theoretical maximum generation level), which show that 2011 MWH generation is not trending any higher than average generation levels of prior years. Exhibit SCE-17, Vol. 6, Part 2, p. 21.

[153] Exhibit SCE 17, Vol. 6, Part 2, p. 32.

[154] Sierra Club Opening Brief, p. 14 (emphasis added).

[155] SCE, Ware, Tr. 13/1843, line 26 through 1844, line 6.

because these replacement high pressure turbine components used a more efficient design, and because they replaced turbine components that were degraded from years of normal service, "the turbines now generate more MW output at the same steam flow, and ***at the same coal feed rate*** to the boiler … ."[156]

In addition, the potential greenhouse gas emissions impacts of the turbine projects were, in fact, assessed by plant operator APS in 2005, prior to SCE approving these projects. APS concluded: "Because the projects will improve efficiency and will not affect the availability or utilization of the units, there is no reasonable possibility that the projects will result in an annual emissions increase."[157] Sierra Club's analysis is misleading and wrong.

4.2.2.4 Sierra Club's Argument About "Basic Operation" Of Four Corners Is A Red Herring

Sierra Club argues that some of the capital projects may cause some incremental reliability increase for Four Corners, and that such an increase, although it would be indisputably good for SCE's ratepayers,[158] is somehow prohibited by the EPS.[159] The only support Sierra Club has for this counterintuitive argument is one of the four "necessity" considerations in D.10-10-016, which states that SCE should consider "whether the investment is necessary to continue 'basic operation' of Unit 4 or Unit 5 within the period of SCE's existing contractual obligations."[160] Nowhere does the Decision state that an increase in plant reliability (which is a good thing) is somehow inconsistent with "basic operation" of the plant. In any event, SCE demonstrated that the capital projects are needed to maintain historical levels of reliability, and are not intended or expected to improve reliability above historical levels.[161]

Sierra Club's "basic operation" argument is really a proposal to run Four Corners to failure. The Commission should take this opportunity to firmly reject Sierra Club's "run-to-failure" recommendation for Four Corners capital investments, which is bad for SCE's ratepayers and for the APS employees who work at the plant. For example, Sierra Club makes the irresponsible assertion that "with respect to its GSU transformer replacement scheduled for 2014, SCE claims that it will experience a 10% probability

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[156] Exhibit SCE-17, Vol. 6, p. 30 (emphasis added).
[157] Exhibit SCE-17, Vol. 6, Part 3, Confidential Appendices, p. B-43.
[158] Exhibit SCE-17, Vol. 6, Part 2, p. 8.
[159] Sierra Club Opening Brief, pp. 14-19.
[160] D.10-10-016, p. 18 (internal quotations added).
[161] Exhibit SCE-17, Vol. 6, Part 2, pp. 19-24.

2.2 Four Corners

Sierra Club's opening brief largely repeats erroneous legal arguments it previously made regarding the Commission's Emissions Performance Standard (EPS). Sierra Club's latest brief suffers from the same flaws embedded throughout its previous briefing on this subject – its arguments are based on what it wishes the EPS prohibited, rather than what the EPS actually prohibits. SCE has already responded to those arguments and will not repeat them here, but will focus on new Sierra Club arguments.[22]

Sierra Club inaccurately characterizes SCE's testimony in the Capital Expenditure Update, arguing that "SCE's stated purpose for these investments is to increase the reliability of the plant."[23] SCE disagrees that "increased reliability" would in any way violate the EPS, but, as SCE has stated many times, the purpose of the reliability-driven investments is to maintain the *historical* levels of reliability at Four Corners, not to increase them.[24] Mr. Ware's testimony on this subject was not "contradictory." Mr. Ware explained that 2011 year-to-date reliability is slightly lower than the recorded 2000-2010 average reliability, and many of the projects presented in Update Testimony are necessary in order to address equipment failures that occurred during 2011.[25] However, these additional projects are neither expected nor intended to improve reliability above historical levels.[26]

SCE has previously explained in great detail how even capital expenditures that increase the efficiency (and corresponding energy output) of Four Corners ***do not*** lead to increased gas emissions.[27] In addition, Exhibit A to Sierra Club's brief is the Commission's draft Negative Declaration showing that SCE's proposed sale of Four Corners (which includes making the 2012 capital expenditures at issue in the Update) has ***no*** negative environmental impacts.

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[22] Sierra Club's continued arguing about the "social justice" implications of Four Corners' existence is not only beyond the scope of this proceeding but hard to understand. Sierra Club states that more than 50% of the Navajo Nation lives below the poverty line. Given that, Sierra Club's crusade to shut down the very plant that provides hundreds of high-paying Navajo jobs and that is one of the pillars of the Navajo economy is bewildering.

[23] Sierra Club Opening Brief On SCE's Four Corners Capital Expenditure Update at p. 1. According to Sierra Club's logic, any expenditure undertaken to repair and return to service a generating unit which tripped off line should be prohibited, because it would "increase reliability."

[24] Exhibit SCE-02, Vol. 6, Part 1, p. 11 and pp. 25-26. Therein SCE also explained that SCE's Decommission Case cost forecast assumes that a degradation in reliability might be acceptable in order to reduce expenditures for the plant's last few years of operations; specifically expenditures for the planned 2014 overhaul and reliability following that overhaul. *See also* Exhibit SCE-17, Vol. 6, Part 2, pp. 19-24.

[25] Exhibit SCE-17, Vol. 6, Part 2, p. 19-24; *see generally* Exhibit SCE-86.

[26] SCE, Ware, Tr. 25/4308:7 – 4309:3; *see also* Exhibit SCE-86, pp. 15-16.

[27] Exhibit SCE-02, Vol. 6, Part 1, pp. 6-7.

Sierra Club is also incorrect when it claims that SCE "failed to conduct any environmental cumulative impact analysis associated with these investments as required by D.10-10-016 …."[28] Sierra Club simply invents the modifier "environmental" before the required "cumulative impact analysis." ~~D.10-10-016 requires no such "environmental" analysis, but rather requires that SCE examine the~~ cumulative impact of the capital projects on "life-extension" and on the basic operation of the plant, including costs and benefits.[29] SCE performed the analysis in its direct testimony, proving that the projects' cumulative effect will not extend plant life, and are cost-effective and necessary to sustain basic operation for the remaining duration of SCE's existing contractual obligations.[30] The additional projects are necessary to achieve these exact same goals, and therefore, they do not change the results of SCE's cumulative effect analysis.[31] Sierra Club's citation to the ***dissent*** in D.10-10-016 arguing otherwise is unpersuasive.

2.3 Ratemaking Treatment Of Bonus Depreciation

2.3.1 DRA Mistakenly Characterizes SCE's Rebuttal As Supporting The "Legality" Of DRA's Income Tax Proposal

In rebuttal to DRA's tax proposals, SCE submitted testimony sponsored by two witnesses, Patricia Y. Wong, SCE's Director of Tax, and James I. Warren, a tax partner in the firm of Winston & Strawn, LLP. DRA dismisses Ms. Wong's testimony, claiming it "essentially repeats, though at greater length, the arguments that SCE made in SCE's original Update Tax Testimony."[32] It appears DRA has not grasped the significance of Ms. Wong's testimony. Most importantly, nowhere, either in its testimony or brief, does DRA address the consequences of violating the normalization provisions of the Internal Revenue Code. This issue is discussed further below.

DRA also misses the point of Mr. Warren's testimony, claiming: "At the outset, then, it seems that SCE's outside counsel agrees that DRA's proposal is *legal*, and only disputes whether it is

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28 Sierra Club Opening Brief On SCE's Four Corners Capital Expenditure Update at p. 3.

29 D.10-10-016 at pp. 18, 26.

30 Exhibit SCE-02, Vol. 6, Part 3, pp. 23-25.

31 SCE's original capital expenditure forecast included funds in anticipation that additional projects would arise that were not foreseen at the time of the forecast, such as those presented in SCE's Update Testimony. In other words, these "new" projects do not change the cumulative economics of SCE's continued participation in Four Corners, because we are not increasing our total 2010-14 capital cost forecast, but rather are merely now spelling out in more detail exactly the "unforeseen" projects that we have incurred since the forecast was prepared. We already included funds for such projects in our original "cumulative effects" analysis. In addition, the new projects do not change the cumulative "life" of Four Corners because SCE is still committed to selling its interest in Four Corners, or if the sale fails, exiting at the end of the current contract in 2016.

Southern California Edison
Four Corners 851 Application A.10-11-010

DATA REQUEST SET A.10-11-010 Energy Division-SCE-001

To: ENERGY DIVISION
Prepared by: Sumner J Koch
Title: Sr Atty
Dated: 12/21/2011

Question 02:

Do the proposed capital improvement projects for 2012 in the application for sale of SCE's interest in Four Corners Generating Station meet the definition of "modification?"

a. If the improvements are not considered "modifications," please provide any correspondence with the EPA or the relevant air permitting agency regarding their concurrence with that determination.

b. If the projects included in the current application for capital improvements do meet the definition of "modification" in the federal New Source Review Rules, then please indicate whether SCE, APS or any other owner has already submitted an application for and/or obtained a permit for the proposed capital improvements. Pleas also indicate whether the application and permit are subject to the Greenhouse Gas (GHG) Tailoring Rule.

Response to Question 02:

No, none of the referenced projects meet the definition of a "major modification" under the New Source Review provisions of the CAA and its implementing regulations.

Moreover, the planned 2012 capital projects are either necessary for environmental or regulatory compliance (and are logically unrelated to capacity factors or GHG emissions), or necessary to maintain unit reliability. Even for the projects designed to maintain unit reliability, none of them will lead to an increase in Units 4 and 5's “capacity factors” as compared to historical baselines, nor lead to an increase in GHG emissions from these units. The 2012 planned reliability projects are generally “like kind” replacements, and there is no reason to believe that these projects, which, if anything, are more minor than those completed in 2007-2011, will lead to increased GHG emissions. See Exhibit SCE-17, Vol. 6, Part 2, p. 32.

In response to Staff’s request that SCE provide correspondence with the EPA “regarding their concurrence with” the inapplicability determinations, SCE wishes to clarify that the NSR rules do not require sources “to obtain any determination from [EPA] before beginning actual construction.” 40 C.F.R. § 52.21(r)(6)(ii); *see also* 67 Fed. Reg. 80,186, 80,192 (Dec. 31, 2002) (Under the 2002 NSR rules, “[y]ou will not be required to obtain ***any*** kind of determination from the reviewing authority before proceeding with construction.”). This is a long-standing principle under the NSR rules, as EPA had confirmed in a 1992 rulemaking. 57 Fed. Reg. 32,314, 32,321

(July 21, 1992) ("[S]ources remain responsible in the first instance for determining what permitting requirements apply to their activities."). Indeed, "source owners or operators in most instances are able to readily ascertain whether NSR requirements apply to them." *Id.* at 32,332. Thus, "in administering [the NSR] requirements, EPA does not require sources to obtain a formal applicability determination before proceeding" with a given project. *Id*. at 32,333; *see also* EPA, *Technical Support Document for the Prevention of Significant Deterioration (PSD) and Nonattainment Area New Source Review (NSR): Reconsideration* (Oct. 2003), at 72 ("The NSR program has always relied upon sources to decide when and whether they need a major NSR permit.") (*available*: www.epa.gov/NSR/documents/petitionresponses10-30-03.pdf). In short, there is no correspondence with EPA regarding these projects because the rules do not require such correspondence or any "concurrence" by EPA.

1 attachment

SCE17V06P02.pdf

Application No.:	A.10-11-015
Exhibit No.:	SCE-17, Vol.6 (Part 2)
Witnesses:	T. Ware

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(U 338-E)

2012 General Rate Case

Rebuttal Testimony

Generation
Volume 6 (Part 2) – Coal Capital Expenditures
Chapters IX-XIII

Before the

Public Utilities Commission of the State of California

Rosemead, California
July 5, 2011

SCE-17: Generation
Volume 06 - Coal Capital Expenditures

Table Of Contents

SCE-17: Generation
Volume 06 - Coal Capital Expenditures

Table Of Contents (Continued)

SCE-17: Generation
Volume 06 - Coal Capital Expenditures

List Of Tables

Table	Page

SCE-17: Generation
Volume 06 - Coal Capital Expenditures

List Of Figures

Figure	Page

I.

INTRODUCTION

No party proposes reductions to SCE's cost forecast to complete the decommissioning of SCE's share of the co-owned coal-fired Mohave Generating Station, nor does any party oppose continuation of the Mohave Balancing Account for the 2012 GRC rate cycle. TURN proposes that the Commission adopt a rate of return of zero for the remaining investment and decommissioning costs of Mohave.[1] SCE addresses TURN's proposal in our rebuttal testimony, Exhibit SCE-25, Vol. 2.

TURN also proposes to adjust SCE's 2010 Four Corners capital expenditure forecast downward by $8.333 million (SCE share, nominal, work order level), by adopting SCE's actual recorded 2010 expenditures of $21.513 million rather than SCE's forecast 2010 expenditures of $29.846 million.[2] SCE has continued to work with plant operator Arizona Public Service (APS) and the other plant co-owners to reduce and postpone capital expenditures to the extent practical. However, as discussed in more detail in Chapter II, $2.397 million of the 2010 under-run was because of the postponement of a single project from 2010 to 2011. That $2.397 million project is the needed expansion of the fly ash disposal area, specifically, the Dry Fly Ash Disposal Area Phase 2, Units 4&5 project, that had been forecast for 2010. The project is now in progress and is expected to be completed in 2011. Therefore, SCE agrees to a $5.936 million reduction (i.e., $8.333 minus $2.397 million) to our 2010 forecast, but not to the entire $8.333 million reduction proposed by TURN. SCE has updated its 2010 capital forecast to reflect the reduction of $5.936 million and its 2011 capital forecast to reflect the increase of $2.397 million (Exhibit SCE-25, Volume 1).

Sierra Club is the only other party that directly discusses SCE's 2010-2014 capital expenditure forecast for the co-owned Four Corners Generating Station coal-fired plant, and certain 2007-2009 recorded capital expenditures being reviewed in this proceeding as required by D.10-10-016 issued by the Commission in response to SCE's Petition to Modify the Greenhouse Gas Emissions Performance Standard (EPS) for Four Corners. Sierra Club's testimony primarily focuses on whether or not Four Corners capital expenditures comply with the EPS and D.10-10-016. Sierra Club discusses certain specific projects to support its position that SCE's capital showing generally does not fully comply with the EPS and D.10-10-016. However, Sierra Club does not appear to propose any specific reductions to SCE's capital expenditure forecast.

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1 Testimony of Robert Finkelstein on behalf of TURN, p. 9.

2 Testimony of William B. Marcus on behalf of TURN, pp. 24-25.

Four Corners capital expenditures being reviewed in this GRC total $138.475 million (nominal, SCE Share, work order level).[3] This consists of $129.927 million of projects forecast to enter service during 2010-2014 (including expenditures for these projects recorded in 2009 and prior) Exhibit SCE-2, Volume 6, Part 2, p. 10, Table X-1, and $8.548 million of projects completed during 2007-2009 that were not approved in SCE's 2009 GRC. Exhibit SCE-2, Volume 6, Part 3, p. 14, Table XVIII-9. Approximately half of the 2010-2014 forecast projects have been completed through mid-2011 and are in-service.

The $138.475 million of projects under review includes $103.533 million of projects that are necessary for sustaining plant reliability, $12.161 million of projects that are necessary for sustaining plant safety, and $22.780 million of projects that are necessary for environmental compliance.[4] Sierra Club does not appear to dispute any of the projects required for safety and environmental compliance. Sierra Club appears to focus solely on the necessity and cost effectiveness of the reliability-based projects, and their impact on plant "life."

The $138.475 million of projects under review includes $97.916 of projects that cost more than $1 million each (SCE Share) and $40.558 million of projects that cost less than $1 million each.[5] There are 124 projects costing less than $1 million each, and as explained in more detail in SCE's direct testimony, these include projects in all three categories (Reliability, Safety and Environmental Compliance).[6] As shown in Table I-1 below, of those projects that cost more than $1 million each, 23 are primarily reliability-driven, two are safety-driven and 12 are for environmental compliance.[7]

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[3] This $138.475 million figure is reduced to $132.539 million assuming the $5.936 million downward adjustment discussed in Chapter II is made in order to account for 2010 cost under-runs. For consistency with SCE's direct testimony, the remaining dollars presented herein are based on SCE's $138.475 million total.

[4] *See* SCE direct testimony, Exhibit SCE-2, Vol. 6, Parts 2 & 3. In order to assure consistency throughout this rebuttal testimony, these figures incorporate the reclassification of one project (Unit 4 Coal Pipe Replacement) from reliability to safety; also see footnote 7.

[5] SCE's 2010-2014 forecast includes two line items (which we count as two "projects") totaling $6.456 million as an Allowance for Unknown Projects. In the above figures, we accounts for these two items as part of the "projects costing less than $1 million" category, although it is possible that projects could arise, that are not known at this time, that could exceed $1 million, that would be funded from these two line items. Sierra Club does not appear to dispute the reasonableness of these two line items. See SCE direct testimony, Exhibit SCE-2, Vol. 6, Part 2, pp. 34-36, for further discussion regarding these two line items.

[6] Exhibit SCE-2, Vol. 6, Part 2, Chapter XII

[7] The two safety projects are for replacement of eroded coal conveyor pipe, on Unit 4 and Unit 5, respectively. In SCE's direct testimony regarding these two coal pipe projects, Unit 4 was categorized as reliability-driven and Unit 5 as safety-driven. These coal pipe replacement projects have significant element of both safety (fire prevention) and reliability, and in this rebuttal we account for both in the safety category rather than splitting them into two categories.

Table I-1
Summary of Four Corners Capital Expenditures
$1,000 - Nominal - SCE Share

No. of Projects	Project Type	SCE Share
23	Reliability Projects > $1 Million	70,678
2	Safety Projects > $1 Million	9,233
12	Environmental Compliance Projects > $1MIllion	18,005
124	All Projects < $1 Million	40,559
161	TOTAL	138,475

Decision No. 10-10-016 requires SCE to demonstrate the reasonableness of 2007-2011 Four Corners capital projects costing $1 million or more by addressing the necessity, costs and benefits of the capital expenditures, and whether the expenditures will likely extend the life of the units. In addition it requires SCE to conduct a study on the feasibility of continuing to maintain its interest in Four Corners after 2011, including estimating the costs of future investments, and to provide a report on its study and a proposed course of action in this GRC. Sierra Club's testimony appears to focus almost entirely on the $70.678 million of reliability-related projects costing over $1 million, as its main argument appears to be that these large reliability projects were not “necessary,” or alternatively, that other options were available at lower cost in their place, that would have allowed SCE to continue “basic operation” of the plant. For example, Sierra Club states:

> Thus, these projects are not solely intended maintain “basic operation” of the power plant, but will result in an incremental increase in the reliability of the affected unit. (Sierra Club, page 8)

Sierra Club specifically focuses on reliability projects that involve the replacement of the following four types of equipment items: Boiler Tube Sections, High Pressure Feedwater Heaters, Generator Step-Up Transformers, and High Pressure Turbine Component Sections. As shown in Table I-2 below, these four types of projects represent $45.076 million of SCE's total capital expenditure showing, and account for 12 of the 23 reliability projects costing over $1 million each.

Table I-2
Reliability Projects Costing Over $1 Million Each
$1,000 – Nominal – SCE Share

No. of Projects	Reliability Projects > $1 Million	SCE Share
7	Boiler Tube Section Replacements	30,021
1	HP Feedwater Heater Repl, Unit 5	1,920
3	GSU Transformer Replacements	6,490
1	HP Turbine & Controls Repl, Unit 4	6,645
12	SUB-TOTAL, Directly Discussed by Sierra Club	45,076
2	2007 Unforeseen LP Turbine Blade Repairs	4,270
2	1AA Transformer Bank Replacements	5,332
3	Generator Field and Stator Rewinds	7,054
1	Boiler Combustion Instrumentation Repl, Unit 5	1,920
2	Air Preheater Basket Replacements	5,026
1	Stack Liner Installation, Unit 5	2,000
11	SUB-TOTAL, Other Large Reliability Projects	25,602
23	TOTAL	70,678

Sierra Club questions the compliance of reliability-related expenditures with the EPS (D07-01-039) and with D.10-10-016, and questions whether SCE has provided all of the information needed to demonstrate the compliance and the necessity of the projects. SCE rebuts these assertions in Chapters III and V. We have already provided, in our direct testimony and workpapers, all of the information needed to prove that all projects are necessary and comply with Commission requirements. However, out of an abundance of caution, in our appendices to this rebuttal testimony we provide the additional information (to the extent available) requested by Sierra Club, much of which we believe has no relation to the actual issues being reviewed in this proceeding (e.g., heat balance diagrams for the plant's original design). See Appendix B.

Sierra Club argues that SCE's capital projects make plant life extension more likely, and that the projects increase reliability rather than sustaining it at historic levels. Sierra Club claims that lower cost options were available to SCE's capital expenditures. Sierra Club argues that SCE's economic evaluations are flawed, and challenges some of SCE's assumptions regarding replacement power costs and the impact on plant reliability if the project were not performed. SCE rebuts these assertions in Chapters IX, X, XI, XII and XIV, where we demonstrate that the projects are the most economic option available, remain economic over a wide range of assumed replacement power costs, and that our reliability assumptions are well founded.

Sierra Club appears to agree that none of the projects increase the generator nameplate MW rating of Unit 4 or Unit 5. However, Sierra Club argues that the projects increase (or might increase) MW output in other ways, and Sierra Club apparently believes that this violates the EPS and/or D.10-10-016, although Sierra Club does not specifically state that conclusion. Sierra Club lists additional information that SCE should be required to provide "to fully understand the effects of any such changes" on generating unit MW capacity that certain projects might have caused.[8] SCE rebuts this claim in Chapter VIII, where we demonstrate that none of the projects increase generating unit capacity in any manner contrary to the apparent objectives of the EPS or D.10-10-016.

Other than for a few projects, Sierra Club does not appear to propose specific reductions to SCE's capital expenditure forecast, nor does it provide detailed discussion of exactly what expenditures (if any) SCE should have made in lieu of those projects. The only "project-specific" conclusions that Sierra Club appears to reach are:

- In reference to the $30.021 million (SCE Share) Unit 5 Boiler Nose Tubes Replacement forecast for 2014, Sierra Club states: "Let us say, for the sake of argument, that extensive maintenance of the nose tubes could have kept the reliability of a Four Corners unit at a reasonable level for another five years, and would have cost only 40% of the cost of the capital project to replace all the tubes. It follows that 60% of the cost of the capital project was for life extension."[9]

- In reference to the $1.920 million (SCE Share) Unit 5 High Pressure (HP) Feedwater Heater Replacement forecast for 2014, Sierra Club states: "If the objective was only to maintain a reasonable level of unit reliability for the next five years, it is likely that alternatives were available that would have cost considerably less..."[10]

- In reference to GSU Transformer Replacements, which SCE assumes Sierra Club intends to include the $1.882 million (SCE Share) Unit 4 T629 transformer replaced in 2010, as well as the Unit 4 T641 transformer and Unit 5 T1092 transformer forecast to be replaced in 2013 and 2014, respectively, at $2.304 million each (SCE Share), Sierra Club states: "SCE assumes that the only alternatives are to replace both transformers or wait for a failure. In fact, there are other alternatives. For example, in 2010, SCE could have bought one transformer, and kept it as a spare for both units. If a transformer failed, the resulting outage would have been only a few days rather than eight months. Thus, most of the benefit of the projects could have been obtained for about half the cost..."[11]

[8] Testimony of Robert Koppe on behalf of Sierra Club, p. 17.

[9] Testimony of Robert Koppe on behalf of Sierra Club, p. 9.

[10] Testimony of Robert Koppe on behalf of Sierra Club, p. 9.

[11] Testimony of Robert Koppe on behalf of Sierra Club, p. 10.

- In reference to the $6.645 million (SCE Share) Unit 4 HP Turbine Section and Turbine Controls Replacement completed in 2010, Sierra Club states: "Therefore, SCE incorrectly claims that it was necessary to spend $16.15 million [sic] on the replacement project in order to keep the HP turbine from degrading the reliability of the unit for during the next five years. In fact, that same goal could have been achieved by spending $1.37 million..."[12]

SCE rebuts Sierra Club's claims regarding each of these four types of projects in Chapters IX, X, XI and XII. In Chapter XIII we show that, for all types of projects, SCE consistently chose the most cost-effective option available. We demonstrate that all of the projects completed during 2007 through 2011 (including the remaining 2011 projects still underway at this time) comply with D.10-10-016. We prove that that the forecast 2012-2014 capital expenditures comply with the EPS, and as explained in direct testimony, we show that our 2012-2014 capital forecast was specifically provided in response to D.10-10-016, a fact which Sierra Club ignores. We demonstrate that Sierra Club misinterprets the EPS and D.10-10-016, and misrepresents the reasons that SCE approved certain projects. We demonstrate that past and forecast Four Corners capital projects that are at issue in this proceeding are necessary, reasonable and fully compliant with the Commission's directives, and should be approved.

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12 Sierra Club, page 11 (Confidential). Sierra Club makes the same general argument regarding the essentially identical project that was completed on Unit 5 in 2008; however, the Unit 5 project is not at issue in this proceeding as it was approved by the Commission in SCE's 2009 GRC. SCE has not redacted the $1.37 million figure referenced by Sierra Club; rather SCE maintains that the APS report which contains this figure is subject to confidentiality as it is not practical to redact the detailed turbine design data ("Critical Electric Infrastructure Information') contained throughout the report.

II.

SCE AGREES THE FOUR CORNERS 2010 FORECAST CAN BE REDUCED, BUT NOT BY THE FULL AMOUNT COMPUTED BY TURN, BECAUSE WHILE THE DRY FLY ASH DISPOSAL AREA PHASE 2 PROJECT WAS DELAYED, IT REMAINS NECESSARY AND WILL BE COMPLETED IN 2011

TURN proposes to adjust SCE's 2010 Four Corners capital expenditure forecast downward by $8.333 million (SCE share, nominal, work order level), by adopting SCE's actual recorded 2010 expenditures of $21.513 million rather than SCE's forecast 2010 expenditures of $29.846 million.[13] SCE has continued to work with plant operator APS and the other plant co-owners to reduce and postpone capital expenditures to the extent practical. However, $2.397 million of the 2010 under-run was because of the postponement of a single project from 2010 to 2011. That $2.397 million project is the needed expansion of the fly ash disposal area, specifically, the Dry Fly Ash Disposal Area Phase 2, Units 4&5 project that had been forecast for 2010. The project is now in progress and is expected to be completed in 2011. Therefore, SCE agrees to a $5.936 million reduction (i.e., $8.333 minus $2.397 million) to our 2010 forecast, but not to the entire $8.333 million reduction proposed by TURN. SCE has updated its 2010 capital forecast to reflect the reduction of $5.936 million and its 2011 capital forecast to reflect the increase of $2.397 million (Exhibit SCE-25, Volume 1).[14]

The plant generates several different waste streams. Some waste is recycled and the remainder is disposed of on-site. This includes dry fly ash. Dry fly ash is sold, for use as a concrete additive, to the extent practical. The portion that exceeds what can be sold is disposed in an on-site landfill. This project constructs phase 2 on an ongoing expansion of the dry fly ash disposal area for continued ash disposal. Units 4 & 5 cannot operate without flyash disposal. This Phase 2 Fly Ash Landfill expansion is required to increase the square footage of the Phase I landfill, based on the projected fill rates. The expansion will consist of utilizing bottom-ash for foundation berms, which will be constructed using a mix of dirty dry fly ash and clay. These new berms will elevate the containment levees around the landfill. This environmentally-driven project is currently underway and scheduled to be completed during 2011 (or, potentially, early 2012) to coincide with the first phase land fill reaching capacity.

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[13] Testimony of William B. Marcus on behalf of TURN, pp. 24-25. SCE’s 2010 capital forecast for Four Corners is found in Table X-1, p. 10 of Exhibit SCE-02, Vol. 6, Part 2.

[14] *See* discussion in Chapt. 2 of SCE-17, Vol. 10, where SCE expresses its opposition to updating its 2010 capital forecast.

III.

SIERRA CLUB MISREPRESENTS SCE'S ASSUMPTIONS AND GOALS, AND COMMISSION DIRECTIVES, REGARDING FOUR CORNERS

D.10-10-016 grants SCE a partial exemption from the EPS for Four Corners. It also requires SCE to address the reasonableness, necessity, and costs and benefits of SCE's 2007-2011 Four Corners capital expenditures, and whether the expenditures will likely extend the life of the units by one or more five-year periods. In addition it requires SCE to conduct a study on the feasibility of continuing to maintain its interest in Four Corners after 2011, including estimating the costs of future investments, and to provide a report on its study and a proposed course of action in this GRC. SCE has provided information responsive to all of these requirements in our direct testimony. However, D.10-10-016 and the EPS are not the only Commission directives that govern SCE's management of Four Corners.

Four Corners is one of SCE's lowest-cost generating resources. When Four Corners incurs outages, SCE usually must procure replacement power, which almost always has a higher cost than Four Corners generation. Indeed, this importance was recognized by the Commission in D.10-10-016, where the Commission found:

> Given the important role Four Corners has played and currently plays in SCE's energy supply portfolio, the long-term contractual commitments SCE has made to its co-tenants, and the limited time remaining under the co-tenancy agreements, we find that it is prudent to allow certain capital expenditures incurred prior to January 1, 2012, subject to our review and approval prior to any recovery in rates. D.10-10-016, page 1.

In our annual Energy Resource Recovery Account (ERRA) proceedings, the Commission requires SCE to prove the reasonableness of SCE's efforts regarding power plant reliability and fuel use, including at Four Corners. The Commission reviews SCE's power purchases related to Four Corners outages, as well as the reasonableness of Four Corners coal use and costs. Neither the EPS nor D.10-10-016 relieved SCE of the responsibility to operate Four Corners in the most cost-effective manner practical for our customers, for the remaining duration of our plant participation.

Among Sierra Club's criticisms regarding SCE's decisionmaking is that SCE's forecast of replacement power costs is too high, stating: "For example, for the second half of 2010, the Southern California on-peak day-ahead spot market price for replacement energy in Southern California was approximately 3.5 cents per kilowatt hour."[15] SCE agrees that *recent* replacement power costs have generally been lower than the forecast used for our Four Corners capital project economic analyses, as

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15 Testimony of Robert Koppe on behalf of Sierra Club, p. 13.

the forecast was produced when replacement power costs were higher. It is also possible that power prices will rise in the future. Nevertheless, as discussed in more detail in Chapter XIV, the Four Corners capital expenditures remain highly economic even assuming SCE significantly over-estimated replacement power costs.

For example, a 1% decrease in reliability equates to Unit 4 and Unit 5 each incurring additional outage time each year of approximately 87.6 hours, or approximately 3.7 days (i.e., 1% of one year). This represents 131,400 MWH (i.e., 750 MW x 2 Units x 87.6 hrs), which has a value of approximately $4.6 million using Sierra Club's $35 per MWH figure. Coincidentally, the 2009 forced outages related to the four boiler tube leak repairs on these units averaged 88.8 hours each; i.e., each tube leak in 2009 represented an approximate 1% impact on reliability. The 2010 forced outages related to the six boiler tube repairs averaged 114.4 hours each.

Despite the fact that tube leak outages continue to be a major contributor to unreliability and actually *increased* between 2009 and 2010, and further ignoring that a *single* tube leak outage represents a 1% or higher impact on unit reliability with a replacement power expense likely costing well over $1 million, Sierra Club then falsely argues that SCE's boiler tube section replacement expenditures were not necessary to sustain “basic operation,” stating:

> ... replacement of selected [boiler nose] tubes would be less expensive than replacement of all the tubes and would maintain the historical rate of failures of the tubes, *or even reduce the failure rate*, for the duration of SCE’s contractual obligation to the Four Corners Power Plant... The same logic and conclusion almost certainly apply to at least some of the other boiler tube replacement projects, and to many other projects as well. SCE should provide evidence to show that the cost of *improving* the units is not greater than the cost of *maintaining* them for the next five years.[16]

As shown in our economic analyses, and as explained in more detail in Chapter IX, boiler tube panel replacements are a common part of routine major overhauls, and specifically, are part of the 2010 and 2014 routine overhauls at issue in this proceeding. All of the boiler tube replacement projects completed during the 2010 routine overhaul were certainly more cost effective than simply "maintaining" the tubes as proposed by Sierra Club, even assuming significantly lower replacement power prices. Those planned for 2014 also have extremely rapid pay-backs, and their precise economics depend on exactly when SCE would exit the plant assuming we are still a participant at that time.

However, our disagreement with Sierra Club is more fundamental than the specific assumptions used for the economic analyses we conducted *for each and every* applicable reliability project. Sierra

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[16] Testimony of Robert Koppe on behalf of Sierra Club, pp. 8 and 9, emphasis added.

Club appears to believe that because of the EPS and D.10-10-016, SCE is now required to demonstrate that we *minimized capital costs* to the maximum extent possible, *even if* that required a reduction in reliability or fuel efficiency and caused a correspondingly larger *increase* in maintenance, fuel or replacement power costs. Sierra Club opines:

> If all that is desired is to maintain "basic operation" or *reasonable* levels of reliability for the remainder of SCE's contractual obligation in the power plant, there are many other, lower cost options that will accomplish this goal while costing much less than the many large-scale component replacements for which SCE is seeking ratepayer compensation. (Sierra Club, page 8, emphasis added.)

Sierra Club does not define "reasonable levels of reliability" and provides practically no support for its blanket assertion. Sierra Club provides almost no information or analysis on exactly *what* alternatives they propose, and those few examples that they do provide are erroneous as explained in subsequent chapters of this rebuttal. Sierra Club does not provide any specific cost estimates for their mythical project alternatives, except for selective quotation from one report concerning the HP Turbine component section replacement. Sierra Club provides no information on the differences in unit reliability, repair costs, replacement power costs or fuel efficiency that would result from their purported alternatives as compared to the actual projects that SCE implemented.

SCE disagrees with Sierra Club's apparent interpretation of the EPS and D.10-10-016, where, in Sierra Club's view, SCE was compelled to avoid all capital spending except that needed to maintain an ill-defined "reasonable level of reliability." As Sierra Club states on page 2 of its testimony, pursuant to D.10-10-016, for projects which are primarily needed to sustain plant reliability, SCE is required to demonstrate:

> (ii) whether the investment is necessary to continue basic operation of Unit 4 or Unit 5 within the period of SCE's existing contractual obligations; (iii) whether, in considering the cost *and benefits* and the prohibition on long-term investment at Four Corners, the investment is necessary within the period of SCE's existing contractual obligations (D.10-10-016, Ordering Paragraph 1c, emphasis added.)

Unlike Sierra Club, SCE did *quantitatively* consider these cost and benefit trade-offs, as documented in our economic analyses, and as explained in our direct testimony:

> Management of the total cost of our Four Corners operations is a *primary* SCE objective. Total cost management involves taking into account the *inter-relationship between O&M, capital and coal fuel expenditures,* and the cost of replacement power and energy when Four Corners electrical production is constrained during forced and scheduled outages. (SCE-2, Vol. 6, Part 1, page 15, emphasis added.)

Unlike Sierra Club, SCE appropriately considered the Commission's concerns regarding power plant reliability, as the Commission noted in D.10-10-016 (see above) for those projects completed prior to 2012, and when assessing the EPS compliance of post-2011 forecast projects at issue in this proceeding, summarized by the Commission as follows:

> Finding of Fact 31. Requiring that every replacement of equipment or addition of pollution control equipment would trigger compliance with the EPS does not recognize that the plant and its operation may remain essentially unchanged and such alternations may not even increase the level of expected emissions from the facility over the long-term. More importantly, this approach could reduce powerplant reliability as old parts are repaired rather than replaced. (EPS Decision, page 231.)

In our direct testimony, SCE explained that past capital expenditures were needed to sustain plant reliability to approximate historic levels. Sierra Club incorrectly argues that "the projects will serve to *increase* the levels of reliability of the units and not just maintain those levels." We rebut Sierra Club's erroneous assertion in detail in Chapter VI.

Sierra Club ignores that, in our direct testimony, SCE presented two separate forecasts for *future* expenditures: one assuming the plant is sold (which is SCE's preferred course of action and is pending before the Commission in A.10-11-010), and another assuming SCE continues to participate through the mid-2016 termination of the existing co-ownership agreements, at which time the plant would be decommissioned. As we explained therein, we *already* assume that if the plant is going to be decommissioned then some reduction in plant reliability might be an appropriate trade-off to reduce expenditures during the last few years of plant operation, stating:

> ...we assume that the plant co-owners will agree that incurring some risk of a small level of performance degradation is an acceptable trade-off in order to achieve modest reductions in 2012-2014 O&M expense, and more significant reductions in 2012-2014 capital expenditures... (SCE-2, Vol. 6, Part 1, page 23.)

> For this [2016 Decommission] case we include in our forecast only those projects which appear necessary to assure continued safety and regulatory compliance as needed to allow plant operation through 2014, and that appear needed to assure that plant reliability does not significantly decrease from historic levels. (SCE-2, Vol. 6, Part 2, page 2.)

Sierra Club also ignores that the Commission specifically directed SCE to provide information, including forecast capital expenditures forecast for 2012 and beyond, that is necessary so that an informed decision can be made regarding the future of SCE's share of the plant, as follows:

> Southern California Edison Company (SCE) must conduct a study on the feasibility of continuing to maintain its interest in Four Corners Generating Station (Four Corners) after December 31, 2011 and must include a report on its study and a proposed course of action. SCE must submit the study in its 2012 general rate case prior to a final determination on rate recovery for any investment at Four Corners ... [and] ... The study must include ... a. Estimates of the costs of future investments in Four Corners if SCE were to maintain its interest in Four Corners ... . (D.10-10-016, Ordering Paragraph 3.)

SCE provided this information in our direct testimony at SCE-2, Vol. 6, Part 3. Therein, SCE explained that it is not practical to modify the plant to comply with the EPS, or to continue operating the plant while ceasing all capital expenditures. We explained that SCE is attempting to exit the plant as rapidly as practical, while returning to the customers the residual value of SCE's plant share. We explained that it is not possible to complete the proposed sale prior to 2012, and therefore, we have worked with APS and the other owners to minimize capital expenditures during 2012 in anticipation of sale closure in October 2012. We further explained the issues that could delay sale close or even terminate the sale, in which case SCE would continue to co-own the plant up until (potentially) the end of the current co-ownership agreements (which generally expire in mid-2016).

For these reasons we provided a 2012-2014 capital expenditure forecast in this proceeding. We included evidence that demonstrated that these forecast 2012-2014 capital expenditures do not violate the EPS, and should be approved so that the plant can continue to operate reliably and safely until a sale of SCE's plant share is consummated, or until the plant permanently shuts down. In the following chapters, we further demonstrate that the many additional misleading assertions made by Sierra Club do not change the conclusions presented in our direct testimony. Those conclusions are supported by evidence demonstrating that the recently-completed and forecast future capital expenditures are reasonable and compliant with the EPS and D.10-10-16.

IV.

SIERRA CLUB'S CLAIM REGARDING FOUR CORNERS LIFE EXPECTANCY IS COMPLETED UNSUPPORTED BY SCE'S AND OTHER CO-OWNERS LONG-STANDING PRACTICES AND HISTORIC ACTIONS, AND MISINTERPRETS THE EPS

Sierra Club claims that Units 4 and 5 were:

> ... designed with the expectation that they would operate for 30 -35 years and then be retired or relegated to peaking service. Since the units, which were built in the 1960s, have now operated beyond their originally expected lifetimes, it is not surprising that some major components have worn out. Replacement of any one of these components contributes to extending the life of the unit. Replacement of many worn-out components is extension of the life of the unit. (Sierra Club, page 4 and 5.)

Sierra Club provides no support for this assertion. The Units 4&5 co-ownership agreements were entered into for a term of 50 years, including the time required for design and construction.[17] These agreements do not expire until July 2016. The coal fuel supply contract and land lease were also entered into for 50 years. There is no evidence that the owners ever took any action to reduce that 50-year initial life expectancy. Actions taken by SCE, including capital spending decisions, have been entirely consistent with the original 50-year life expectancy. Assertions made by Sierra Club to the contrary are simply unsupportable speculation that the units have already "operated beyond their originally expected lifetimes." Sierra Club fails to clarify exactly "who" it is that "expected" Units 4&5 to have a lifetime of only 30 or 35 years; certainly it was not SCE or the other co-owners.

More importantly, Sierra Club fails to explain how SCE's 2007-2011 projects, and the life expectancy information we provided in our direct testimony in response to D.10-10-016, do not comply with D.10-10-016’s requirements, which granted Four Corners a partial exemption from the EPS.[18] SCE explained how the expenditures do not extend life because they do not extend the time period of the existing co-ownership agreements, and SCE does not plan to continue participating in the plant beyond the term of those agreements.[19]

Relative to our 2012-2014 forecast projects, in the preceding chapter and our direct testimony we already explained the reason for those projects. We do not believe they extend life for the same reasons; i.e., SCE does not plan to continue to participate beyond the expiration of the current co-ownership

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[17] As indicated in SCE direct testimony, SCE-2, Vol. 6, Part 1, p. 6, Units 4 and 5 actually entered service in 1969 and 1970, respectively. They are currently approaching 42 years of age.

[18] Exhibit SCE-2, Vol. 6, Part 3, pp. 24-25 and Appendix C.

[19] Exhibit SCE-2, Vol. 6, Part 1, p. 1.

agreements, which remains the most logical basis with which to compare potential life-extending effects of a project. SCE will continue to fund these forecast projects if economics dictate that they make sense depending on the circumstances in place at that time.

Regarding forecast 2012 expenditures, the sale agreement with APS contemplates that SCE will fund capital expenditures consistent with the requirements in the underlying co-ownership agreements. SCE has presented these forecast 2012 expenditures for approval in the sale proceeding as well as in this proceeding. Should the proposed sale be denied, or should it not successfully conclude for other reasons, SCE assumes that we would continue to participate in the plant until our participation is terminated through the successful conclusion of a replacement sale, or until the end of the current co-ownership agreements. In our direct testimony, SCE has shown that these expenditures are EPS-compliant and economic, and in subsequent chapters in this rebuttal we provide further information in support of our conclusions.

Regarding 2013-2014 forecast expenditures, SCE explained in our direct testimony that many of these 2013-2014 projects will likely not be completed if the owners decide to shut down and decommission the plant at the end of the current ownership agreements. However, they are provided in our GRC forecast as required by D.10-10-016, and because the circumstances we might encounter during 2013-2014 might dictate that these expenditures be undertaken in order to minimize costs for SCE customers. SCE believes the principles outlined in D.10-10-016 should be applied to our 2012-2014 forecast expenditures. SCE also believes that the EPS does not prohibit SCE from making 2012-2014 expenditures, as discussed in more detail in our direct testimony.[20]

Sierra Club's assertion that, since the plant is now older than 30 or 35 years of age, that "replacement of any one of these components contributes to extending the life of the unit" is tantamount to saying that the EPS prohibits all expenditures made after a plant is 30 or 35 years of age. This would have meant that SCE would have had to immediately abandon its interest in Four Corners, as it is not practical to continue to operate the plant without incurring ongoing capital expenditures. If this was the intent of the EPS, it could simply have said so. Sierra Club's claims are essentially an attempt to re-litigate the EPS.

[20] Exhibit SCE-2, Vol. 6, Part 3, Chapter XXII.

V.

SIERRA CLUB'S CONCERNS THAT PLANT LIFE MIGHT BE EXTENDED AFTER SCE DEPARTS ARE BEYOND THE SCOPE OF THE ISSUES IN THIS PROCEEDING

Sierra Club argues that maintaining the units, rather than allowing them to degrade, facilitates life extension rather than retirement, stating:

> SCE says that the remaining lives of the units are based on contractual agreements and are unrelated to the projects themselves. However, within the constraints of the contractual agreements, the decision to retire or to extend the lives of the units will depend strongly on the condition of the units. If the units are in poor condition, it will cost more money to continue operating them, so continued operation is less likely. If the units are in good condition, continued operation will be more economical and therefore more likely. (Sierra Club page 6.)

Interestingly, throughout most of its testimony, Sierra Club argues that unit reliability will *not* suffer if capital spending is radically reduced below SCE's forecast. Yet, here, Sierra Club argues that SCE should not be allowed to make these same capital expenditures, because doing so will avoid the performance degradation that would result if that same spending were not undertaken. Sierra Club can not have it both ways, and it is here where Sierra Club is correct; i.e., if the capital expenditures were not made, the plant's reliability, safety and fuel efficiency performance would suffer and other costs (such as repair costs and fuel costs) would increase.

SCE certainly agrees that the capital expenditures at issue in this proceeding were (or will be) needed to maintain the plant performance to recent historic levels. SCE also agrees that, theoretically with all other things being equal, a hypothetical power plant that has been maintained is more likely to remain in active service (i.e., not be retired or relegated to back-up capacity) compared to one that has not been maintained. However, SCE questions the applicability of this hypothetical scenario to the actual current circumstances impacting Four Corners. First, SCE believes that the capital spending at issue in this proceeding will have very little bearing on the future of Four Corners Units 4&5 *after SCE's participation ends*, compared to other factors impacting the plant. These factors include securing a cost-effective coal fuel supply contract for post-2016 operations, and expenditures that will likely be needed to comply with the final EPA FIP that will almost certainly require Units 4&5 air pollution reductions.[21] Secondly, even if one assumes that the capital spending at issue in this GRC makes Units 4&5 continued operations more likely *after* SCE terminates our participation, such an assumption does not mean that

[21] The US Environmental Protection Agency is currently assessing the need for additional NOX emissions air pollution reduction retrofits at Four Corners, and in the near future, is expected to issue a final Federal Implementation Plan (FIP) requiring reductions. *See* SCE direct testimony Exhibit SCE-2, Vol. 6, Part 1, pp. 13-14.

the expenditures violate the EPS or D.10-10-016. SCE has made clear that we do not plan to participate in any such life extension that might be undertaken by others after we depart.

Neither the EPS nor D.10-10-016 prohibit SCE from divesting our plant share while it is still in a reliable state, rather than in a degraded state. Neither the EPS nor D.10-10-016 prohibit divestiture as a means to achieve compliance, and in any case, any arguments to the contrary should be litigated in SCE's Section 851 plant sale proceeding (A.10-11-010) and not in this GRC.

As explained above, SCE's capital expenditure decisions have been based on minimizing total plant costs for the duration of our own remaining participation, while adhering to the capital expenditure constraints of the EPS and D.10-10-016. These capital expenditures can not be so perfectly timed or designed such that historic reliability is maintained right up to sale closure (or alternatively, July 2016), and then suddenly collapses on that date. Nor can SCE unilaterally shut down the jointly owned Four Corners plant.

When an equipment item requires replacement because of failure or anticipated failure in the near future, and there is no practical alternative to that replacement other than plant shut-down, that equipment item must be replaced with currently-available equipment. For many such replacements, it is more cost effective to purchase replacements that use current technology, and therefore, it might (in some ways) be better than the older-generation equipment being replaced. Likewise, it is not feasible to procure a custom replacement that will function for four years and then miraculously self-destruct in July 2016. Where lower *total* cost (i.e., after considering capital, O&M, replacement power and fuel costs) options were available based on the expected duration of SCE's remaining participation and other information known at the time, they were selected.

The Commission has already recognized the need to maintain coal plant reliability, including funding needed capital expenditures, as they approach the possible end of their operating life. In SCE's 2003 GRC, SCE faced uncertainty regarding the remaining life of the Mohave Generating Station. SCE and the other owners had not yet secured needed extensions to the plant's original coal supply and water supply agreements, which were scheduled to expire on December 31, 2005. Mohave also needed several hundred million dollars of capital expenditures for air pollution retrofits in order to operate beyond 2005. Parties argued that SCE's already limited 2001-2005 capital expenditure plan should be further reduced, because the plant might cease operating at the end of the 2003-2005 rate cycle. In comparing Mohave to a car that might be retired at the end of 2005, the Commission held:

> A prudent owner who is in a position of having to operate the car for at least two more years will not necessarily limit expenditres to tires, brakes, and other safety components, but will instead perform all repairs and maintenance necessary to assure reliable automotive performance for those two years. An experienced automobile mechanic might advise the owner to install new spark plugs even though that might not improve safety. A prudent owner would heed that advice even though the mechanic did not determine through rigorous statistical analysis the probability that the old spark plugs would fail within two years. It almost certainly would not make sense for the vehicle's owner to plan on operating the vehicle on seven cylinders during its final years. (D.04-07-022, pages 65 and 66.)

> [T]he evidence does not support ORA's conclusion that SCE's planned capital spending should be limited to the bare minimum needed for regulatory requirements, environmental protection and safety. SCE's testimony shows that most of its planned investments, such as those for steam turbine buckets (blades), boiler tubes, electrical cables, and other components whose failure could cause a shutdown, are important for reliable operations at Mohave through 2005. (D.04-07-022, page 66.)

> We are concerned that cutbacks as severe as these may unduly impact production reliability. Whethere or not Mohave continues to operate after 2005, determination of which is beyond the scope of this GRC, we intend to authorize the capital funding that is necessary for continued safe, reliable, and environmentally responsible operation of the plant through 2005. (D.04-07-022, page 67.)

SCE faces a very similar situation here. We are attempting to conclude the proposed Four Corners sale as rapidly as practical. Meanwhile, we must continue to maintain the plant in a reliable and safe condition as required by the sale, or alternatively, should the sale not successfully conclude, as required so that operations can cost-effectively continue for the remaining duration of our participation, which will not extend beyond mid-2016.[22] The Commission correctly recognized the importance of maintaining Mohave reliability, even up until what was later revealed to be its final day of operations on December 31, 2005. SCE believes maintaining Four Corners reliability (and safety), until our participation ends, is equally important and we have acted (and continue to act) accordingly.

Sierra Club simply refuses to accept that SCE's primary concern governing our capital spending decisions has been (and remains) to assure cost-effective, safe and reliable operation for the remaining duration of our plant participation. In Sierra Club's zeal to find fault with SCE actions to sustain safe and reliable operations until our participation ends, Sierra Club invents hypothetical scenarios that have no relation to the projects being reviewed in this proceeding, stating:

[22] That is, SCE will not participate in plant operation beyond mid-2016 without Commission approval. Also, if the plant is decommissioned commensurate with existing ownership agreements, the actual decommissioning work might extend beyond 2016.

> Consider what would happen if the boiler in one of the units exploded. (This is an unlikely occurrence but has happened to more than one unit in the industry.) Rebuilding the boiler would take one to two years and cost many millions of dollars. No one could reasonably claim that such a rebuilding was not life extension of the unit. Nonetheless, the SCE analysis would find that it was not life extension, since it would not alter any contractual agreements. (Sierra Club, pages 3 and 4.)

SCE assures the Commission that if a Four Corners boiler explosion occurs, that requires potentially hundreds of millions of dollars and a one-to two-year outage to replace it, we will engage the Commission before proceeding with the replacement. In fact, in our direct testimony, SCE already addressed a similar future circumstance involving hundreds of millions of dollars and a lengthy outage. Specifically, several months ago (prior to D.10-10-016 final issuance) we assessed the anticipated capital work that will likely be required for the plant to comply with the air pollution FIP currently being promulgated the EPA, and we summarized that assessment in our direct testimony as follows:

> Approximately on or shortly before the Co-Tenancy Agreement expiration, it is likely that several hundred million dollars of capital expenditures will be required to install NOX (nitrogen oxides) emissions abatement equipment in order to comply with a Federal Air Implementation Plan that the US Environmental Protection Agency is currently developing for the station. It appears that such an investment would not be cost effective unless the plant continues to operate for well beyond the existing expiration dates of the various leases and co-owner contracts which govern its operation. It appears that such expenditures would conflict with the EPS and would likely conflict with the anticipated final decision on SCE's EPS Petition. Given the EPS, SCE informed the other co-owners that SCE does not plan to fund major emissions abatement retrofits that might be required by the EPA. SCE further indicated that we do not plan to continue our participation beyond the expiration of the current ownership agreements, and we are also exploring options to accelerate the end of our participation. (SCE-2, Vol. 6, Part 2, page 5.)

SCE has approved those projects that are necessary to sustain cost effective operation for the remaining duration of our participation, and SCE has *not* approved projects that are not necessary to achieve this goal. Contrary to Sierra Club's claims, the projects approved by SCE and at issue in this proceeding have not and will not increase plant reliability above recent historic levels, and have not impermissibly increased the MW output of the plant.

VI.

SIERRA CLUB'S CLAIM THAT THESE PROJECTS ARE NOT NECESSARY BECAUSE THEY IMPROVE PLANT RELIABILITY, RATHER THAN SUSTAIN IT, IS DEMONSTRABLY FALSE

Many of the projects at issue in this proceeding have already been completed, some as long as ago as 2007. Projects forecast for the remainder of 2011 and 2012, and for 2013-2014 should SCE still be a participant, are similar to those completed during 2007-2010. In turn, these 2007-2014 projects are similar to capital projects routinely completed at the plant during the many years leading up to 2007, and to those approved by the Commission in SCE's 2009 GRC and completed during 2007 through 2009. Replacement of worn out coal piping, fatigued turbine blades, aging transformers, degraded boiler tube panel sections, corroded and eroded heat exchangers and air preheater baskets, obsolete control systems where repair parts are no longer available, and so on, are routine at power plants such as Four Corners. For example, in 2006, the year which immediately precedes the start of the capital expenditures at issue in this proceeding, SCE recorded $9.012 million of capital expenditures (SCE Share, nominal, work order level).

As SCE explained in direct testimony, capital spending normally peaks in the year before (i.e., for replacement equipment procurement), and in the year during routine major overhauls (i.e., for replacement equipment installation). Routine major overhauls provide the several-week-long outage required for many equipment replacement installations. In order to minimize total outage duration over the life of the plant, routine major overhauls are typically only conducted every six years on each unit, and were most recently conducted in 2002 (Unit 5), 2004 (Unit 4), 2008 (Unit 5) and 2010 (Unit 4).

While such routine capital spending might appear large in absolute terms, it is only one component of the overall cost to operate large coal-fired generating units, such as Units 4&5. For example, SCE's share of coal fuel for these two units was approximately $89 million and $75 million in 2009 and 2010, respectively. Similarly, our 2012 Test Year O&M forecast is approximately $44 million (SCE Share, $2009). As explained earlier, the monetary value of the power output of Units 4&5 is also very large, exceeding $1 million per day, even assuming Sierra Club's figure of $35 per MWH.[23]

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[23] 750 MW x 2 Units x 24 Hrs x $35/MWH = $1.260 million.

In spite of this history, Sierra Club argues that the capital expenditures at issue in this proceeding go beyond those needed to sustain unit reliability at historic levels, and summarizes their belief as follows:

> In fact, it is my experience that all these reliability-focused projects are not at all necessary just to maintain historical reliability, or even to prevent large decreases in reliability. Instead, they will tend to extend the life of the plant by *increasing* the overall reliability of a unit ….[24]

Sierra Club's claim in demonstrably false. As shown in Figure VI-1 below, Units 4 and 5 have already operated at relatively high reliability (i.e., Equivalent Availability Factor) and Capacity Factor for many years. As a practical matter, there simply is not much room for further improvement, and certainly not by continuing to maintain the plant in like fashion to what has been done in the past.

Figure VI-1
Four Corners Units 4&5 Combined EAF and CF

Capacity Factor (CF) is the percentage of actual MWH generation each year compared to the theoretical maximum generation possible if the generating units were to operate at its full rated capacity 24 hours per day, 365 days per year. Equivalent Availability Factor (EAF) is the percentage of time that the units are available for full rated generation operations, whether or not they are actually dispatched to full rated load when available to do so. The figure above provides the recorded Units 4&5, combined, EAF and CF for 2000 through 2010.[25] As shown, CF is approximately equal to EAF because Units 4&5 are very economic and therefore are typically operated at full load when available to do so.

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[24] Testimony of Robert Koppe on behalf of Sierra Club, p. 8.

[25] Capacity Factor was computed by dividing average recorded net MW output by the current approximate net output of 770 MW for each unit, when operating at full load. This provides a consistent basis to allow a direct comparison of all 11

(*Continued*)

As shown, during 2000 through 2010, Units 4 and 5 (combined) annual recorded EAF has ranged from approximately 75% to 91%, and averaged approximately 83%. It is not feasible for a generating unit to sustain a 100% EAF, because the unit must periodically be removed from service for maintenance. According to the North American Electric Reliability Corporation (NERC) Generation Availability Data & Statistics (GADS) data base, the average EAF achieved by coal-fired power plants over the past 5 years is approximately 84%. At 83%, the average EAF performance of Units 4 and 5 over the past 11 years is within one percent this North American average.[26]

Figure VI-1 also shows that Unit 4 and 5 EAF and CF (i.e., annual generation output) have been relatively flat over the past 11 years. The dips and peaks in CF and EAF primarily reflect the timing of major outages. These major outages include the routine major overhauls discussed above, as well as unplanned turbine repair outages lasting several weeks experienced in 2007 on both units due to turbine blade failures. These major outages explain why the EAFs recorded in 2002, 2004, 2007, 2008 and 2010 are all lower than all of the EAFs recorded in 2000, 2001, 2003, 2005, 2006 and 2009.

Figure VI-1 shows no discernable trend to support Sierra Club's allegation that 2007-2014 capital expenditures at issue in this proceeding have caused, or will cause, reliability to increase, rather than to be sustained at recent historic levels. In fact, the EAF recorded during 2007-2010, at approximately 80%, is actually lower than that recorded during 2000-2006 at approximately 85%. The EAF recorded to date through May 2011 (the most recent month of available statistics) shows no evidence of appreciable changes in EAF performance, with a 2011 year-to-date EAF of approximately 80.8%, which is slightly below than the 2000-2010 average of approximately 83%. The 2011 data also does not show any evidence of appreciable changes in CF performance, with a 2011 year-to-date CF of approximately 73.8%, which is below than the 2000-2010 average of approximately 82.1%.

Sierra Club does not specify exactly *when* it expects this surge of improved reliability to occur, nor does it list exactly *which* projects it expects will cause it. Based on 2010 and 2011 year-to-date reliability statistics, it certainly does not appear to be those projects already completed through 2010 that are at issue in this proceeding. These completed projects include approximately $50 million (SCE Share)

Continued from the previous page

years of historic data. Equivalent Availability Factor is computed based on hours of availability as compared to 8,760 hours in each year (or 8,784 hours in leap years), and therefore does not rely on a specific unit MW rating.

26 Based on the most recent, comparable industry-wide GADS data currently available: “Fossil - Coal Primary, All MW Sizes, 2005-2009,” This data is provided in our supporting Appendices.

of projects that entered service in 2010 (mostly associated with the Unit 4 major overhaul), and approximately $9 million of projects that entered service during 2007-2009 that are being reviewed pursuant to D.10-10-016.[27]

Nor is it in any way likely that plant reliability will surge as a result of capital spending anytime during 2011 or 2012, given that significantly fewer projects will be completed during 2011 and 2012 as compared to those completed during 2007-2010. Our 2010-2014 Sale case capital expenditure forecast of approximately $130 million includes only approximately $12 million that is forecast to record during 2011 and 2012.

Our Sale case forecast includes approximately $62 million in 2013-2014, mostly associated with the forecast 2014 Unit 5 overhaul. The reliability impacts of most of those projects will not occur until after that 2014 overhaul is completed. However, as these 2013-2014 forecast projects are very similar to those completed during 2007-2010 and in prior years, SCE does not believe that these projects will cause plant reliability during 2014 through 2016 to surge above 2000-2010 levels.

As explained in Chapter III, SCE did not include any of the $32.686 million of forecast 2014 Unit 5 overhaul capital projects in our Plant Decommission case. SCE assumes that is the plant is to cease operation by mid-2016, it *might* be more cost effective to cancel many (or perhaps even all) of these 2014 overhaul projects and incur reduced reliability, and we assume this in our Decommission case forecast. However, as explained in our direct testimony, we include the 2014 Unit 5 overhaul projects in our Sale case because we do not yet know exactly when the proposed sale will close, or if it might terminate for other reasons.[28] If the proposed sale is not successfully consummated, the best option for SCE customers *might* be to continue to maintain the plant (including by performing the 2014 overhaul) while seeking another buyer for SCE's share, and we assume this in our Sale case forecast. The exact decision regarding these 2014 projects would depend on the actual circumstances encountered during 2012 and 2013.

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[27] SCE's 2012 GRC does not include $50.866 million of projects that entered service during 2007-2009 that were already approved in SCE's 2009 GRC (SCE direct testimony, Part 3, p. 12). SCE's 2012 GRC forecast includes $25.792 million (SCE direct testimony, Part 3, p. 1) of expenditures that recorded prior to 2010 for projects entering service during 2010-2014. Most of these pre-2010 recorded expenditures were for projects that entered service in 2010. The $50 million (SCE Share) estimate for 2010 projects is based on the total of these pre-2010 recorded expenditures for work in progress, plus SCE's 2010 forecast expenditures, minus the 2010 downward adjustment recommended by TURN as modified by SCE in Chapter II.

[28] SCE direct testimony, Exhibit SCE-2, Vol. 6, Part 3, Chapter XXII.

Like all GRCs, our 2012-2014 expenditures are a *forecast*. It is not possible to perfectly predict the rate at which the 2014 overhaul equipment replacements in our forecast will continue to degrade between now and the overhaul. If those items fail or demonstrate an increased risk of failure prior to the 2014 overhaul, and SCE is still a participant, it might well be more economic to replace them rather than to defer them. It is also not possible to identify exactly what other equipment replacement needs might arise, such as because of sudden catastrophic failure, that are not currently foreseen, although history indicates that such needs routinely arise. We believe our 2012-2014 expenditure forecast is a reasonable basis for 2012 GRC ratemaking, and demonstrates the likely projects and costs that will be incurred as SCE works to conclude the proposed sale in October 2012, or should SCE's participation beyond that point continue due to sale closure delays or other reasons.

Sierra Club's arguments concerning the reliability impacts of these projects also ignores that other factors, besides capital spending, can affect plant reliability. These include maintaining a cost effective balance between break down repairs and preventative repairs, and the training and qualifications of operations and maintenance personnel. Also, if one uses too narrow of a timeframe to measure reliability, one can obtain misleading results. The frequency of outages is often somewhat random rather than being evenly spread every month, or even every year. The overall reliability trend might be different when viewed from a wider timeframe perspective as compared to a more narrow perspective.

Fundamentally, Sierra Club ignores that while a capital expenditure to replace a degraded equipment item avoids increasing numbers of outages that would otherwise be caused by *that* equipment item, the plant is constructed of *hundreds* of such equipment items that can cause outages and these equipment items degrade at different rates. As one item is replaced, a different item then invariably arises that needs replacement.

Four Corners reliability-related capital spending is simply a part of the plant's overall maintenance process. Equipment items that wear out are replaced; i.e., partially replaced where practical, and completely replaced where more cost effective to do so. If these equipment replacements are being performed at a rate that essentially matches the rate at which these hundreds of equipment items are wearing out, then the *overall* plant reliability levels should *not* be expected to significantly change either up or down. Sierra Club's arguments that the capital spending at issue here will increase reliability ignores this simple principle, and more importantly, ignores actual plant historical reliability data, and should be rejected.

For many years, the reliability of Units 4 and 5 has been relatively high, and has been consistent with other coal plants. Their average availability since 2000 is already within one percent of the North American average for coal power plants. It makes no sense to conclude that planned and completed 2007-2012 routine expenditures, that are like-kind with numerous expenditures made in the past, have caused or will cause Units 4 and 5 to materially exceed the average EAF recorded by similar coal power plants across North America. Nor does it make sense to conclude that the similar capital expenditures forecast for 2012-2014, most of which are for the planned 2014 overhaul and which SCE has not included in the Plant Decommission capital expenditure cost forecast, would cause a material increase in reliability should SCE still be a plant participant during those years.

VII.

SIERRA CLUB'S CLAIM THAT FOUR CORNERS CAPITAL EXPENDITURS ARE A MASSIVE LIFE EXTENSION PROGRAM IS DEMONSTRABLY FALSE

Sierra Club claims that the capital expenditures in this proceeding represent the final phases of a "massive life extension program" stating:

> The number of components that will need replacement is substantial, but it is finite. It appears that, during 2005-2014, a majority of the components that will need to be replaced for life extension have been, or are about to be, replaced. Based on the types of capital investments for which SCE is seeking ratepayer compensation, it appears that massive life extension programs for these units are nearing completion. (Sierra Club, page 5-6.)

This is demonstrably false. To begin with, Sierra Club fails to explain how spending prior to 2007 has any relevance to this rate case. But, even ignoring their complete lack of relevance, expenditures during 2005 and 2006 were fairly modest. As previously explained, capital expenditures routinely are higher in the year before and during major overhauls, and these overhauls are conducted approximately every six years on each unit. Therefore, capital spending was $2.235 million in 2005, and was $9.012 million in 2006 (SCE share, nominal). Spending then increased in 2007 in preparation for the 2008 overhaul. Spending was then higher during 2008-2010 for the 2008 and 2010 overhauls. As shown in direct testimony, spending is relatively low in 2011 and 2012, and then is forecast to increase in 2013 in preparation for the 2014 overhaul. This is the normal, logical spending pattern, given that the purpose of the routine major overhauls is to repair and replace degraded equipment.

Sierra Club overstates the extent of the 2007-2014 projects, even from its own apparent interpretation of "massive life extension program." Sierra Club appears to be arguing that the projects conducted since 2005 replace a considerable portion of Units 4&5. This is simply not the case. While several equipment items were and will be replaced, the number of replacements is extremely small in comparison to the population of existing Units 4&5 equipment (and supporting systems) that is not being replaced. It is not practical to provide a comprehensive list of equipment that has not been replaced. However, one can assess the magnitude of SCE's 2007-2012 capital expenditures by comparison to the total cost that would be expended were SCE to entirely replace Units 4&5 with like-kind generating units.

According to the US Department of Energy the approximate cost to construct a pulverized coal supercritical power plant is $2,024 per kW of capacity ($2007).[29] As Units 4&5 have a nameplate rating of 818 MW, this equates to a cost of over $3.3 Billion, which translates to approximately $1.589 billion given SCE's 48% share of Four Corners Units 4&5. By comparison, SCE's total capital expenditures during 2007-2011 total approximately $123.4 million and 2012-2014 forecast capital expenditures total approximately $67.1 million (i.e., assuming the forecast 2014 Unit 5 overhaul projects are performed), for a total of $190.5 million (SCE Share).

These 2007-2014 expenditures therefore equate to only approximately 12% of the "replacement power plant" cost amount, or approximately 1.5% of this amount for each of the eight years in question (i.e., 2007-2014). If one spends only 1.5% of the new plant construction cost in each year, it would take approximately 67 years before one expended the total cost to construct a new coal plant. Clearly, the expenditures in this proceeding do not represent a "massive life extension program" as Sierra Club inteprets the term.

Sierra Club qualifies its claim with a footnote, that states:

> Typically, the major components that wear out as a unit operates beyond its originally expected lifetime are some but not all of the sections of boiler tubes, some but not all boiler headers, some or all feedwater headers, the condenser tubes, and the generator windings. (Sierra Club, footnote 2, page 5.)

Clearly, Sierra Club understands that the 2005-2014 projects do not replace all of the boiler tubes, feedwater heaters, or generator windings, let along any of the dozens of other categories of equipment at Four Corners. In Chapter IV, we rebutted Sierra Club's erroneous claims regarding "originally expected lifetime." Here, we simply note that Sierra Club provides no actual explanation of why SCE's partial replacements of individual equipment items as they wear out represents life extension. Sierra Club's argument certainly does not align with the Commission's EPS, where the Commission explained the kinds of projects of concern. The Commission’s EPS decision (D07-01-039) restricts new investments in SCE’s own existing, non-CCGT baseload powerplant that: (1) are designed and intended to extend the life of one or more units by five years or more, or (2) result in a net increase in the rated capacity of the powerplant. The EPS then provides additional guidance on the types of expenditures that are allowed and prohibited, stating:

[29] "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2" dated November 2010, by the National Energy Technology Laboratory, US DOE.

> ... we will define “new ownership investments” to include any investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more ... We believe that the definition above covers “repowering” as the term is generally used in the industry, since the types of renovations normally undertaken during repowering (e.g., replacing one or more of the plant’s existing turbine(s)) would significantly extend the life of the unit(s), increase the rated capacity of the powerplant, or both.) (D.07-01-039 at p. 53.)

> Repowering generally refers to the construction of new generating units at an existing site and the complete or partial dismantling of existing generation units at the same site. Existing unit are not always entirely retired or dismantled. Generators can often re-use the busbar/ transformer arrays, transmission tap lines to grid interconnect, water and gas supply lines and cooling structures during repowering. (*Id.* at p. 7.)

> Requiring that every replacement of equipment or addition of pollution control equipment would trigger compliance with the EPS does not recognize that the plant and its operation may remain essentially unchanged and such alternations may not even increase the level of expected emissions from the facility over the long-term. More importantly, this approach could reduce powerplant reliability as old parts are repaired rather than replaced. (*Id.* at Finding of Fact 31.)

Regarding the prohibition on increasing the plant’s rated capacity, the EPS explains that:

> ‘Rated capacity’ refers to the plant’s maximum rated output under specific conditions designated by the manufacturer and usually indicated on a nameplate physically attached to the generator. (*Id.* at p. 53.)

SCE's 2007-2014 capital expenditures do not constitute “repowering,” and do not increase generator nameplate capacity. Sierra Club's arguments concerning "massive life extension" are not supported by the facts.

VIII.

<u>ALL PROJECTS COMPLY WITH D.10-10-016, HAVE NOT CHANGED GENERATOR NAMEPLATE RATED MW CAPACITY, AND HAVE NOT CHANGED CAPACITY IN ANY OTHER MANNER THAT DISCERNABLY INCREASES GREENHOUSE GAS EMISSIONS</u>

The EPS prohibits capital investment that "is intended to extend the life of one or more units of an existing baseload powerplant for five years or more, or results in a net increase in the existing rated capacity of the powerplant" and explains that "'Rated capacity' refers to the plant's maximum rated output under specific conditions designated by the manufacturer and usually indicated on the nameplate physically attached to the generator."[30] As SCE indicated in our direct testimony, SCE-02, Vol. 6, Part 3, none of the GRC expenditures increase the generator nameplate rating of Unit 4 or Unit 5.

Related to the generating unit capacity effects of the projects in this GRC, Sierra Club primarily argues that the capital expenditures may have increased Units 4 and 5 rated capacity in ways *other* than nameplate capacity, stating:

> Even if one focuses on the capability of the generator(s) in a unit, it is the actual capability, and not the number on a nameplate, that matters for the purpose of evaluating emissions. (Sierra Club, page 15-16.)

Sierra Club expresses specific concerns regarding the HP Turbine Section Replacement projects conducted on Unit 5 in 2008 (approved in SCE's 2009 GRC) and Unit 4 in 2010, stating:

> The HP turbine upgrades actually did increase the amount each unit was capable of generating continuously to 770 MW (net). (Sierra Club, page 15.)

While the HP turbine section replacements did *not* increase generator nameplate rating, Sierra Club is correct that these replacements did increase the operational MW output over what it had generally been for several previous years. This increase resulted from two issues: (1) the existing HP turbine components were degraded, and (2) the replacement components used a modern design that achieves higher output at the same steam flow. That is, this increased MW *output* was achieved by using the same *inputs* of fuel and steam flow; i.e., without a discernable increase in GHG emissions. SCE provided this information in our direct testimony, SCE-2, Vol. 6, Part 1, page 6.[31]

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[30] EPS, p. 5.

[31] Exhibit SCE-2, Vol. 6, Part 1, p. 6: "Since the completion of the Unit 5 major overhaul in 2008, the net output of Unit 5, when operating at full load, has averaged approximately 770 MW. This primarily reflects the partial replacement of the high pressure (HP) section of the steam turbine during the overhaul. This replacement was needed to sustain plant reliability as the original HP turbine inner shell section was badly degraded and at risk of catastrophic failure. The replacement HP components are of a more modern design and are able to generate a higher MW output at the same coal fuel and steam flow rates. Unit 4 underwent this same replacement during its 2010 overhaul."

Perhaps more importantly, Sierra Club ignores that SCE was granted a partial exemption from the EPS in D.10-10-016. D.10-10-016 does *not* require SCE to demonstrate that projects completed through 2011 do not increase MW capacity in a manner contrary to the EPS or any other standard. Rather it requires SCE to address the reasonableness, necessity, and costs and benefits of the expenditures, and whether the expenditures will likely extend the life of the units. As discussed in more detail in Chapter XII, the HP turbine section replacements were the most cost-effective option available to address turbine degradation and possible catastrophic failure.

SCE provided this same capacity-related information, concerning the HP Turbine section replacement projects, to the Commission during the course of the proceeding that culminated in D.10-10-016. Sierra Club's apparent concerns regarding their capacity impacts should have been voiced during that proceeding.

Sierra Club also ignores the fact that Unit 4 and Unit 5 are *not* routinely operated above their generator nameplate original design output, even following the HP Turbine Section replacements. Unit 4 and Unit 5 each have a generator nameplate rating of 818 MW.[32] When operated at full load, the current “gross” output of the Unit 4 and 5 generators averages approximately 810 MW, each. An appreciable amount of this “gross” power output is consumed within the Four Corners plant in order to power the numerous plant equipment items that are required to operate Units 4&5. These items include fans, pumps, coal pulverizers, air compressors and an extensive amount of air pollution control equipment. This auxiliary power consumption (or “parasitic load”) averages approximately 40 MW for Units 4 and 5, each. Therefore, Units 4 and 5 provide to the bulk power grid a “net” output (i.e., the “gross” output minus the auxiliary consumption) of approximately 770 MW each.

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[32] There are two generators on each unit, one drive by the Low Pressure Turbine, one driven by the High / Intermediate Pressure Turbine. The Unit 4 and Unit 5 nameplates are identical. The LP and HP/IP turbines cannot be operated independently of each other. Operating the unit requires that both turbines and both generators to be operated. When the unit is on line, it is not possible to vary the MW output of either the HP/IP generator, or the LP generator, without affecting the output of the other. Each generator has a nameplate that specifies its MVA design rating at an assumed set of operating conditions (i.e., at a specific hydrogen gas pressure and power factor). The nameplate MW rating is determined by multiplying the MVA rating stated on the nameplate, by the power factor stated on the nameplate. It is perfectly safe and normal to operate at a lower gas pressure if a generator owner opts to do so, but this reduces MW output. Four Corners normally operates at the rated (i.e., nameplate) gas pressure. It is normal for the generator's actual operating power factor to vary based on grid requirements, as power plants are generally required to operate at the power factor specified by the grid operator based on grid needs. Therefore, generators are typically designed to be operated over a range of power factors. The MW output of the generator varies based on the power factor. Therefore, the manufacturer also provides charts that supplement the nameplate, that show the MW output over the range of power factors that the generator can be safely operated.

With the HP section replacements, the turbines now generate more MW output at the same steam flow, and at the same coal feed rate to the boiler needed to produce that steam. SCE has no reason to believe the HP turbine section replacements caused Unit 4&5 greenhouse gas emissions to increase, and Sierra Club apparently does not believe so either. Nowhere in its testimony does Sierra Club directly argue that the GRC expenditures increase greenhouse gas emissions, individually or collectively.

Other than for the HP Turbine Section replacement project, Sierra Club fails to clearly state exactly which other projects (in their view) increase "actual capability" (rather than nameplate capacity). nor do they provide their basis for such a conclusion. Most importantly, they do not or explain *why* this should be impermissible. We assume Sierra Club's concerns include projects forecast for 2012-2014. Related to 2012-2014 projects, SCE believes that the same principles outlined in D.10-10-016 should apply, as we explained in Chapter III. In whatever manner the Commission decides to assess the post-2011 projects, SCE disagrees with Sierra Club's attempt to write the concept of nameplate capacity out of the EPS as the appropriate standard to assess if projects impermissibly increase rated capacity. In addition to being the clearly-defined Commission standard in the EPS, generator nameplate rating is a widely-recognized industry standard for defining a generating unit's MW capacity. If Sierra Club believes the EPS should have used some other standard, it should have so argued during the Commission's EPS proceeding.

None of the forecast 2012-2014 expenditures change the generator nameplate capacity of Unit 4 or Unit 5. Sierra Club appears to agree, but then states "SCE also needs to show that there have not been any other changes to the generators, such as upgrades to the generator coolers, that would increase the capacities of those generators."[33] As we stated above, there are no projects (including generator projects) in this GRC that modify the Units 4 and 5 generators in a manner which causes their performances to be fundamentally different from that specified on the nameplate. Incidentally, were such expenditures to be performed, SCE would change the generator nameplate rating to reflect those changes, consistent with standard industry practice.[34]

Sierra Club fails to explain how any of the expenditures in this GRC, including the HP turbine work, increase capacity in any discernable manner that would increase greenhouse gas emissions, and

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[33] Testimony of Robert Koppe on behalf of Sierra Club, p. 16

[34] Such changes are normally documented by attaching a supplemental nameplate to the generator. The original nameplate is typically also left in place, for reference. Units 4 and 5 generators do not have any supplemental nameplates. SCE is not aware of any fundamental alterations having ever been performed on these units that would have triggered the need for a supplemental nameplate.

therefore, future emissions compliance costs, avoidance of which is the stated goal of the EPS. Rather, they argue that it is SCE who must provide the required (in Sierra Club's opinion) demonstration, stating: "The Company must show that changes to the boiler and/or the turbine in either of the units did not change the capacity of that unit."[35]

In order to assess Sierra Club's concern, we begin by acknowledging that Sierra Club is correct that actual MW output is often below that specified on the generator nameplate because of other constraints in the power plant that are not related to the generator itself. Actual unit MW output can be affected by weather, coal quality, degraded or out-of-service equipment, and numerous other reasons. Generator output varies as a function of turbine horsepower delivered to the generator shaft, which in turn varies as a function of steam temperature, pressure and flow, as well as the condition and efficiency of the turbine.[36] Turbine efficiency refers to how much shaft horsepower is produced at a given steam temperature, pressure and flow. As shaft horsepower increases, generator output goes up, assuming all other parameters are equal.

Certainly many of the projects in this GRC will affect (or might theoretically affect) steam temperature, pressure or flow, or turbine condition. Indeed the plant maintenance process involves continually restoring the performance of degraded equipment, and to a large degree, capital expenditures are simply part of that overall maintenance process. Examples include replacement of degraded boiler air preheater baskets, and replacement of worn and fatigued turbine blades. Also, replacement equipment might not exactly match original equipment. Manufacturers continue to seek ways to reduce costs or improve performance. Replacement equipment can result in small (often not measurable) changes to an operational parameter(s). It can be extremely hard to discern such changes, as other variables (such as weather) cause essentially continual fluctuations in operating parameters that can be larger than those resulting from equipment replacement.

Sierra Club appears to argue that SCE needs to exhaustively assess these kinds of equipment-replacement-related changes and present the results in this proceeding. However, it is not practical to do this in the manner apparently envisioned by Sierra Club, which involves a microscopic examination of numerous records as laid out by Sierra Club on pages 17 and 18 of its testimony. It is also not necessary. One can instead simply look at the actual recorded annual greenhouse gas emissions and MWH

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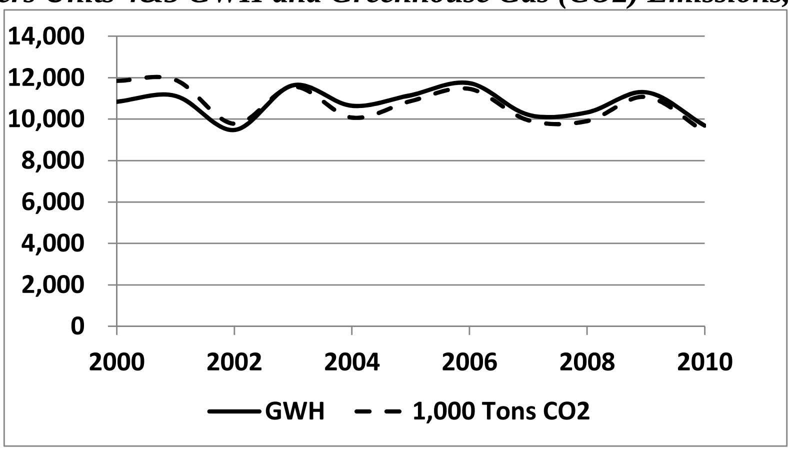
35 Testimony of Robert Koppe on behalf of Sierra Club, p. 16.

36 In addition to such constraints, grid needs or economics might dictate that the unit not be operated at nameplate rated capacity even it is able to do so.

production levels. Based on these records, SCE has no reason to believe that any projects in this proceeding, other than HP Turbine section replacement as already discussed, had any impact on plant MW or MWH output, other than the intended impact of sustaining reliability (and therefore production levels) consistent with recent historic performance. Perhaps more importantly, SCE has no reason to believe that any projects in this proceeding increased greenhouse gas emissions above recent historic levels, and therefore, have the potential to increase future GHG compliance costs assuming SCE were to remain a plant participant.

Figure VIII-2 below provides annual recorded GWH production (i.e., 1,000 MWH) and GHG emissions from Units 4&5 (combined) for 2000 through 2010.[37]

Figure VIII-2
Four Corners Units 4&5 GWH and Greenhouse Gas (CO2) Emissions, 2000-2010



The above figure essentially matches the Units 4&5 Capacity Factor and EAF Figure VI-1 discussed above in Chapter VI. For the same reasons discussed there, the peaks and valleys in the above figure primarily reflect the extended outages conducted in 2002, 2004, 2007, 2008 and 2010. As is the case for CF and EAF, there is no discernable trend that GHG emissions or MWH production levels during 2007-2010 are different than those recorded during 2000-2006. As also discussed in Chapter VI, given that projects forecast for 2011-2014 are very similar to those completed during 2007-2010, there is no reason to conclude that annual GHG levels will appreciably change as a result of these expenditures as compared to 2000-2010 levels, or annual MWH generation levels (i.e., other than perhaps a small

[37] CO2 emissions data from the annual reports to US EPA; 2010 emissions data not yet validated by EPA. This data was provided to CPUC Staff in the context of its CEQA evaluation for the Section 851 proceeding regarding SCE's proposed plant share sale.

increase from the HP Turbine Section replacement projects, although such an annual MWH production increase has yet to materialize).

SCE's Four Corners capital expenditures do not violate D.10-10-016, and do not result in capacity increases in a manner contrary to the EPS. Sierra Club's arguments to the contrary are not valid, and should be rejected.

IX.

SCE FORECAST AND COMPLETED BOILER TUBE REPLACEMENT PROJECTS ARE THE MOST PRACTICAL OPTION AVAILABLE, ARE REASONABLE AND SHOULD BE APPROVED

Sierra Club makes several erroneous claims regarding boiler tube panel replacement projects at issue in this proceeding, and specifically singles out the $1.920 million (SCE Share) Unit 5 Boiler Nose Tube panel section replacement forecast for the 2014 overhaul, stating:

> It appears that the boiler nose tubes have been extensively pad-welded over the years, which has limited the frequency of failures of those tubes to an acceptable rate. It is my experience that more extensive pad welding and/or replacement of selected tubes would be less expensive than replacement of all the tubes and would maintain the historical rate of failures of the tubes, or even reduce the failure rate, for the duration of SCE's contractual obligation to the Four Corners Power Plant. It may well be that replacement of the tubes is the better (more economical) long-term solution. However, if the objective is to maintain unit reliability for another five years, less expensive alternatives almost certainly exist. (Sierra Club page 8.)

To begin with, as explained above, SCE did not include this specific project in our Decommission Case forecast at it is forecast for the 2014 Unit 5 major overhaul. Should SCE still be a participant in 2014 and should the co-owners at that time be planning to decommission the plant consistent with the July 2016 co-ownership agreements' termination, the project might be canceled. In that case, it may be that the cost of the resulting forced outages is more economic than proceeding with the project. However, SCE's disagrees with Sierra Club's apparent attempt to apply the circumstances and economics at issue for this specific project to *all* boiler tube replacement projects.

For this particular nose tube replacement project, the cause of the boiler tube failures (and hence, the cause of the resulting repair and outage replacement power costs) is due to soot-blower and fly ash erosion to the outer tube surface. In these circumstances, it is possible to maintain the tubes for some period of time by periodically weld repairing the damage. However, weld repairs cannot be repeated indefinitely. Repeated weld repairs weaken the underlying steel, and a point is eventually reached where the tube simply must be replaced.

As Sierra Club acknowledges in their testimony, the plant has already been applying this stop-gap weld repair practice for the past several years, and we forecast that we still have another three years to go before the replacement project would be implemented. SCE has reasonably forecast that this temporary weld-repair approach will begin to provide diminishing returns such that by 2014 it will no longer be cost effective, and therefore, we include the replacement project (and other 2014 Unit 5 routine major overhaul capital projects) in our Sale case forecast for the reasons summarized above and in our direct testimony.

While Sierra Club appears to believe otherwise, in fact the boiler nose tube replacement project is the *only* boiler tube replacement project in this GRC where such stop-gap weld repairs are practical even as an interim solution to avoiding an increasing rate of forced outages as the tubes continue to degrade. Table IX-3 below lists the boiler tube replacement projects in this GRC, and summarizes the underlying cause of the tubes degraded condition.

Table IX-3
Boiler Tube Section Replacement Projects
$1,000 - Nominal - SCE Share

Project	Predominant Tube Damage	Year	SCE Share
MIX ZONE WATER WALL REPLACEMENT U 4	Thermal Fatigue	2010	1,457
2ND STAGE PENDANT SUPHTR REPL, U 4	Long Term Overheat, Dissimilar Metal Welds	2010	6,604
PENDANT RH & OUTLET HEADER REPL, U 4	Thermal Cycling, Cracking, Header Creep	2010	7,977
BOILER NOSE REPLACEMENT, U 5	External Erosion, Corrosion, Fatigue	2014	1,920
UPPER ECONO REPL U 5	Fatigue, Corrosion, Erosion	2014	2,640
HORIZONTAL REHEAT BANK REPL, U 5	Long Term Overheat, Erosion	2014	3,029
1ST STAGE PENDANT SUPHTR REPL, U 5	Long Term Overheat	2014	6,394
TOTAL			30,021

Replacement of the damaged areas is the only practical solution to corrosion, the weakening over time of the hundreds of welds that join together tube sections that were fabricated from dissimilar metals, thermal cycling and fatigue, and long-term overheat damage that weakens the steel, and to the resulting tube cracking and internal pitting related to all of these mechanisms. Such damage cannot be cost effectively repaired through welding or any other approach, other than by replacing the damaged tubing. Replacement is also the only practical option to address ash erosion affecting inner tubes that are buried deep within in tight bundles, such as found in the economizer, and therefore (unlike boiler nose tubes), are not accessible for cost-effective weld repair as a stop-gap solution. If one were to attempt to perform stop-gap weld repairs in that situation, accessing these inner tubes within each bundle requires other tubes to be cut out of the way. These cut tubes must then be reinstalled after the inner tubes are repaired. Since it is old tubing that has been cut away, invariably new tubing is used to replace it. Most of the cost of tube repairs is the labor and temporary scaffolding and similar kinds of costs. Using new replacement tubing adds little to the total repair costs compared to attempting to reuse old tubing that is more likely to fail in the near future compared to new tubing.

The only practical alternative to tube panel section replacement to address all the above conditions affecting the six other boiler tube panel replacement projects, is to simply incur an increasing number of costly forced outages, and individually replace the tubes as they fail. SCE disagrees with

Sierra Club's implicit assertion that replacing the entire damaged area pre-emptively, in one single repair, is more expensive than repairing the damaged area one tube at a time over dozens of outages. Even for the one example Sierra Club cites, the Unit 5 boiler nose replacement, Sierra Club completely ignores the fact that the damage already extends to over half the tubes in the area, as SCE explained in direct testimony: "At least 50 percent of the Nose tubes have [already] been repaired by pad welding." (SCE-2, Vol. 6, Part 2, page 28.)

The other tube projects in this GRC address areas where the damage is similarly widespread. When the damage is widespread through-out a particular area, it is more economic to replace the entire area rather than attempting to work around and leave in place the "undamaged" tubes (i.e., those individual tubes that, because they are not as badly as degraded as others in the same area, might be able to remain in service for perhaps five more years or some other time increment). For that matter, it is not even practical (i.e., in outage time or examination expense) to examine every inch of every tube in the damaged area to determine which portion of each tube might remain and which portion must be replaced. Such an exam would be a pre-requisite before one could attempt to salvage some portion of the targeted area. Our economic analyses for each of these projects appropriately looked at the only two feasible options: (1) replace the damaged area, in one outage, or (2) incur increasing numbers of outages to replace them a one (or a few) at a time.

Sierra Club completely ignores that boiler tube leaks have been the leading cause of Four Corners forced outages. As shown in Table IX-4 below, during 2006-2010 tube leak outages averaged 679 hours per year, and accounted for approximately 4% of the total 18% of unavailability of Units 4&5.[38] Projects such as those proposed for this GRC are needed to sustain reliability. If these degraded tube panels are not replaced, reliability will go down.

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[38] Planned outages accounted for approximately 7% of the approximate 18% total, and all other forced outages and derates accounted for the remaining approximate 7% during 2006-2010.

Table IX-4
Units 4 and 5 Boiler Tube Leak Outages

Year	Forced Outages	Outage Hours	% EAF Impact
2006	10	829	4.7
2007	7	604	3.4
2008	8	921	5.2
2009	4	355	2.0
2010	6	686	3.9
Average	7	679	3.9

Like many projects, tube panel section replacements are generally scheduled to coincide with the 6-year routine major overhaul cycle used for Units 4&5. This scheduling is based on the extent of tube panel degradation observed to date, and the estimated further degradation that will occur prior to the next scheduled overhaul. SCE does postpone boiler tube panel replacements when this estimated further degradation does not occur at its previously-estimated rate. For example, the First Stage Pendant Superheater Replacement and Horizontal Reheat Bank Replacement projects currently forecast for the 2014 Unit 5 major overhaul, had previously been forecast for the 2008 Unit 5 major overhaul. However, when the 2008 overhaul date marched closer, it was determined that these two panel sections were not degrading as fast as earlier estimated. Therefore, these projects were rescheduled to the 2014 overhaul at that time.

It would be highly imprudent to not continually address these tube leak outages, including through replacement of damaged boiler tube panel sections during major overhauls. Indeed, such replacements are a key component of the major maintenance to be achieved during routine major overhauls. These boiler tube panel section replacements are an integral part of minimizing *total* costs, as discussed earlier in Chapter III.

Finally, SCE also disagrees with Sierra Club's view that the tube replacement projects in this GRC do not represent selective replacement. They *are* selective replacement. SCE only replaced, or forecasts to replace, tube panels where a large number of tubes in that area show evidence of in-service failure in the near future. The boiler is composed of hundreds of individual tubes, with most tubes well over 100 feet in length as measured from header to header. None of these projects replace all of the tubes in the boiler, and some do not even replace the entire run of tubes from header to header. Regarding the Unit 5 boiler nose panel replacement, the tubes involved run all the way from the bottom to the top of the furnace, and this project only replaces the portion of these tubes that form the boiler nose area. For all of the above reasons, Sierra Club's arguments should be rejected and SCE's boiler tube replacement projects approved.

X.

SCE'S FORECAST FEEDWATER HEATER REPLACEMENT PROJECTS ARE THE MOST COST EFFECTIVE OPTIONS AVAILABLE

In reference to feedwater heater replacement "projects" Sierra Club argues:

> Heater replacements only make economic sense for long-term operation of the units (i.e., life extension). If the objective was only to maintain a reasonable level of unit reliability for the next five years, it is likely that alternatives [to heater replacement] were available that would have cost considerably less." (Sierra Club page 9.)

As shown in the Table X-5 below, there are two feedwater heater projects in this GRC, one is the replacement of the entire heater, and one is a partial replacement (i.e., of just the heater shell).

Table X-5
Feedwater Heater Projects
$1,000 - Nominal - SCE Share

Project	Year	SCE Share
HP FEEDWATER HEATER REPL, U 5	2014	1,920
NORTH 2nd POINT HEATER SHELL REPL, UNIT 5	2009	285
TOTAL		2,205

Based on other similar statements throughout their testimony, Sierra Club appears to direct their comments at only the first project, which is the forecast 2014 complete replacement of the Unit 5 High Pressure (HP) Feedwater Heater at $1.920 million. As already discussed, this project is not included in our Decommission case forecast, because it might later be determined that if the plant is only going to operate for a few years beyond 2014, that incurring additional outages and repairs is more economic than heater replacement.

Sierra Club appears to believe that this one particular heater replacement project is an example that supports its assertion that SCE has not considered other “options” for our numerous equipment replacement projects. In this case, Sierra Club claims that "extensive maintenance [rather than replacement] could have supported basic operation of the heaters for the next five years."[39] This is simply not the case; SCE has considered such options for this project and all other projects, and in fact, where they are the most economic option, we include them in our forecast. For feedwater heaters, such options can include partial rather than total replacement, and the choice depends on the specific circumstances encountered.

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[39] Testimony of Robert Koppe on behalf of Sierra Club, p. 9.

This GRC includes review of the Unit 5 North 2nd Point Heater Shell Replacement completed in 2009. In that case, the heater tube bundle appeared that it could continue to operate relatively reliably for several more years. However, the heater shell was eroded, and could not be cost effectively patch repaired. Therefore, that project consisted of replacing just the heater shell, and re-using the existing tube bundle. We assume that this meets Sierra Club's definition of "maintenance" as an alternative to complete replacement of piece of equipment. However, Sierra Club does not appear to acknowledge this shell replacement project in its testimony, and Sierra Club does not specify exactly what other kind of "maintenance" it believes can be performed in lieu of replacing a degraded feedwater heater.

There is very little routine maintenance required of feedwater heaters. There are no practical maintenance routines that one can implement to mitigate the erosive and corrosive effects that the water and steam have on the heater tubes and shell over time (i.e., other than maintaining water purity, which the plant already does). When heater tubes develop leaks, the leaking tubes are normally plugged off, and it causes lost fuel efficiency and can impact MW output. As the tubes further deteriorate and the failure rate rises, it increases the risks of a turbine water induction event that can cause extensive damage to the turbine.[40] If the problem entails erosion and thinning of the heater shell, the shell is at risk of catastrophic failure. A shell failure will almost certainly cause a generating unit outage, and worse, can damage adjacent equipment and can seriously or fatally injure plant personnel.

The above two projects are the only feedwater heater capital expenditure projects in this GRC; one a complete replacement and one a partial replacement. The plant co-owners have and continue to apply appropriate judgment to the specific circumstances at issue, and strive to implement the most cost effective solution based on the facts known at the time.

In Sierra Club's apparent view, SCE should be required list *all* possible options that might have been considered for each and every equipment replacement project, and to then provide documentation of the reasons why such hypothetical options are not better than the equipment replacement project in question. However, it is simply not possible for SCE to guess what other hypothetical options Sierra Club might have in mind. SCE can only respond in detail to those specific options that Sierra Club

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[40] Feedwater heaters are used to preheat the boiler feedwater upstream of the boiler. The feedwater is routed through the inside of the heater tubes, and the tubes are positioned inside of the heater shell. Steam is extracted from the turbine, and is routed to the shell, where it condenses over the outside surface of the tubes, and in the process, passes its heat to the feedwater. If a tube leaks, it can rapidly flood the heater shell, and in certain circumstances, the water backs up all the way to the turbine. The turbine blades rotate at very high speed. If water (from the heater shell) backs up the steam extraction piping and into the turbine, the rotating blades will then plow through this water, which results in extensive or even catastrophic turbine damage.

actually describes. SCE should not be punished simply because there *might* be other options (whether or not practical or cost effective) that Sierra Club or some other third-party might hypothesize after the fact, that SCE failed to explicitly prove were less practical or cost effective than equipment replacement.

XI.

THE CONTINUED ORDERLY RELACEMENT OF WORN-OUT GSU TRANSFORMERS IS THE ONLY SAFE AND PRACTICAL OPTION AVAILABLE

SCE's capital forecast includes the replacement of three Generator Step Up (GSU) Transformers, as summarized in Table XI-6 below. These transformers "step up" the generator terminal output voltage to switchyard voltage (i.e., transmission line voltage).

Table XI-6
GSU Transformer Replacement Projects
$1,000 - Nominal - SCE Share

Project	Year	SCE Share
GSU TRANSFORMER T629 Repl U 4	2010	1,882
GSU TRANSFORMER T641 Repl U 4	2013	2,304
GSU TRANSFORMER T1092 Repl U 5	2014	2,304
TOTAL		6,490

Sierra Club argues that these projects are not necessary for continued basic operation of the units, stating:

> SCE assumes that the only alternatives are to replace both [sic] transformers or wait for a failure. In fact, there are other alternatives. For example, in 2010, SCE could have bought one transformer, and kept it as a spare for both units. If a transformer failed, the resulting outage would have been only a few days rather than eight months. Thus, most of the benefit of the projects could have been obtained for about half the cost...[41]

SCE disagrees with Sierra Club's unsupported assertions for numerous reasons. To begin with, the Unit 4 and the Unit 5 GSU transformers are *not* identical. The Unit 4 GSU transformer output voltage is 345 kV, and the Unit 5 GSU transformers output voltage is 500 kV. Unit 4 and Unit 5 feed two separate (but interconnected) transmission systems, each having an associated switchyards located at the plant site. These systems operate at approximately 345 kV and 500 kV, respectively. The Unit 4 and Unit 5 transformers are *not* interchangeable.

Units 4&5 each have three GSU transformers (i.e., one for each alternating current electrical phase, A, B and C). Three of the six original transformers were replaced in 2005 and 2008. As of late-2009, the remaining three original GSU transformers were reaching the end of their service lives as revealed through routine periodic transformer testing. We determined that repair was not a cost effective

[41] Testimony of Robert Koppe on behalf of Sierra Club, p. 10.

option for these three transformers, and their respective replacement was scheduled based on these test results, and in conformance with the plant's maintenance outage scheduling practices (which are discussed in more detail later in this chapter). The Unit 4 T629 was then replaced during the 2010 routine major overhaul. The Unit 4 T641 replacement is planned for the 2013 minor overhaul. The Unit 5 T1092 replacement is planned for the 2014 routine major overhaul.[42]

Adoption of Sierra Club's suggestion to purposely operate a large 345,000 volt (or 500,000 volt) transformer to failure would be highly imprudent, and also very uneconomic. Transformer in-service failures risk damage to other plant equipment because of the resulting electrical surge. An in-service failure also can result in a fire, which can jeopardize employee safety, as well as further jeopardizing other plant equipment. Power plant managers do not purposefully operate degraded high voltage transformers to failure given the fire risks and widespread electrical damage that can be caused by such failures.

For example, on May 6, 2011, one of the Unit 5 auxiliary transformers suddenly and unexpectedly exploded while in service, tripping the unit off line, spilling hot oil, and causing a fire.[43] The local fire department responded and was able to quickly extinguish the fire. The explosion and fire damaged cable trays. One employee was taken to the hospital for examination. Fortunately, no one was seriously injured and the event only caused minor scorch damage to adjacent transformers, and the fire did not spread and engulf other oil-filled transformers. Nevertheless, this event clearly illustrates that large equipment items such as transformers are not, and should not, be purposely run to failure, and that occasional capital expenditures have and will continue to arise that were not forecast during annual capital expenditure budgeting and forecasting.

Purposely running a large transformer to failure is also very uneconomic. In addition to the routine major overhauls conducted every six years, APS conducts minor overhauls (typically lasting a few weeks) approximately mid-way between each routine major overhaul, and also conducts reliability outages (typically lasting approximately ten days) in between each minor and major overhaul. This means the normal maintenance plan used at Four Corners is to have four planned outages every six

42 For the same reasons explained regarding forecast Unit 5 2014 overhaul boiler tube panel replacement projects, SCE has not included the T1092 replacement in our Decommission case capital forecast. However, on June 3, 2011, through routine periodic testing, APS discovered that T1092 transformer had significantly degraded since its prior test. APS is now evaluating to what extent its scheduled replacement should be accelerated.

43 Subsequent investigation revealed that a transformer insulating bushing replacement conducted during the outage which immediately preceded the event was not correctly performed.

years, (i.e., one major overhaul, one minor overhaul, and two reliability outages). This equates to one planned outage approximately every 18 months.

Replacement of degraded equipment, such as transformers, are planned in advance such that they can be performed during these schedule outages, where practical. Incurring additional outages reduces plant reliability. Sierra Club erroneously believes that replacement only takes a "few days." Replacing a GSU transformer actually requires an estimated outage of approximately eight day, assuming a suitable replacement is on hand. The replacement power costs from a single additional eight-day outage for the unplanned replacement of a GSU transformer would likely exceed the cost of the transformer.

Consistent with long-standing practice, SCE already defers capital expenditures to the extent practical by, for example, replacing each GSU transformer as needed, rather than simply replacing all six at the first sign of distress on one of them. SCE has continued to carefully monitor the remaining three original GSU transformers, and has forecast the replacements based on this monitoring. Interestingly, while throughout the rest of its testimony Sierra Club argues that projects should be delayed, here Sierra Club attempts to find fault with this approach, claiming:

> Specifically, SCE claims that that the original GSU transformers had a probability of failure that was 10% per year. If this were so, there would be a 40% chance that the Unit 5 transformer will fail during 2010 – 2014. If that were the case, it would be irresponsible to wait until 2014 to replace the transformer. Under its own probability of failure assumption, SCE should have bought the transformer in 2010 or even earlier and should have installed it during the first outage that was sufficiently long. Since transformer replacement only requires a few days of outage time, the replacement should have been done in 2010 or earlier. The fact that SCE is waiting until 2014 to replace the Unit 5 transformer appears to indicate that it does not really believe that the probability of failure of the original transformer is as high as claimed. (Sierra Club, page 14.)

Sierra Club's assertion is completely inconsistent with its proposal to simply buy a spare transformer, and then use it only if a transformer actually fails in service. Sierra Club fails to explain how, on the one hand, it would be "irresponsible" to continue to operate a transformer having a 40% chance of in-service failure, while on the other hand, recommending that SCE simply buy a spare and then wait for the existing GSU transformer to catastrophically fail in service.

But more importantly, Sierra Club completely misrepresents SCE's transformer replacement economic analyses. SCE did *not* indicate that the transformer that is scheduled to be replaced in 2014 had a 10% probability of failure beginning in 2010. The economic analysis for that transformer assumes a 10% probably of failure *beginning* in 2014, not 2010. SCE's economic analysis took account of the fact that, as evidenced by routine testing, all six transformers were *not* degrading at the exact same rate. Our *forecast* of the probability of transformer failure beginning three years into the future, as the transformer *continues* to degrade between now and its forecast replacement, is based on test results to date and our general experience with transformers. These forecasts are then updated as appropriate, as additional information becomes available, such as that generated by future routine periodic transformer testing.

Because the original transformers have all been subjected to essentially the same age-related and operating temperature-related stresses, it appears that the ultimate service lives of all six will fall within a ten-year band, assuming the replacements of T641 and T1092 do not have to be accelerated ahead of their currently forecast 2013 and 2014 dates. This unsurprising result does not mean that SCE simply assumed that all six transformers were identical, although Sierra Club apparently did make such an assumption.

Simply put, Sierra Club's proposal amounts to purchasing one tire as a replacement for a six wheeled truck, where three tires were recently replaced and the other three tires are now approaching minimum tread. Buying *one* new tire, and keeping it as spare, does not provide a real solution to the looming needed replacement of the remaining *three*, particularly considering that the three tires are not identical.

XII.

THE ORIGINAL TURBINE HP COMPONENT SECTIONS WERE AT RISK OF CATASTROPHIC FAILURE AND NUMEROUS MAJOR PARTS NEEDED REPLACEMENT; TURBINE SECTION REPLACEMENT WAS THE BEST OPTION

As discussed in Chapter VIII, the HP Turbine component sections were replaced during the 2008 Unit 5 and 2010 Unit 4 major overhauls. The replacement components used a more modern design that increased MW output without a discernable increase in steam flow, coal fuel use or GHG emissions. In Chapter VIII, SCE addressed Sierra Club's concerns regarding the affect of those replacements on Unit 4 and Unit 5 MW output. Here we rebut Sierra Club's other erroneous assertions regarding these projects.

To begin with, we note that the 2008 Unit 5 replacement is not being reviewed in this 2012 GRC. That project was already approved by the Commission in SCE's 2009 GRC. However, we also note that issues discovered on Unit 5 influenced SCE decisionmaking regarding the identical project on Unit 4, and so we discuss those issues as appropriate. SCE approved the $6.467 million (SCE Share) Unit 5 project in August 2005, and SCE approved the $6.645 million (SCE Share) Unit 4 project in October 2006.[44]

At the outset, we also note that Sierra Club makes several references to a 2005 APS study. Sierra Club then erroneously implies that the referenced study provides all of the information on all of the factors that SCE considered in approving the Unit 4 project, and related to our subsequent actions regarding this project between its approval and its 2010 completion. This is not the case. SCE considered many factors regarding this Unit 4 project, including the condition of the Unit 5 turbine components when that turbine was disassembled for its 2008 overhaul.

Sierra Club's main argument appears to be their belief that other, lower cost options were available to address HP turbine degradation. Sierra Club also erroneously argues that SCE's concerns regarding unit reliability were unfounded, stating:

> In its evaluations, SCE claims that the replacements were needed to maintain the reliability of the units. These claims are based on the assertion that the replacements were needed to prevent long outages of the units that would otherwise occur in the future as a result of failures of blades in the HP turbine. These claims are false. (Sierra Club, page 11.)

Sierra Club then clarifies the above statement, and regarding the first of these two identical projects (i.e., Unit 5 completed in 2008 and not being reviewed in this GRC), states:

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44 While this was before the EPS was issued in January 25, 2007, SCE does not believe that this project violates the EPS.

> For Unit 5, *APS's [2005] analysis* also showed *no future forced outages* due to the existing HP turbine even if that turbine was not replaced. Yet, here again, SCE incorrectly claims that it was necessary to spend $15.45 million on the replacement project in order to keep the HP turbine from degrading the reliability of the unit during the next five years. In fact, that same goal could have been achieved by spending only $3.58 million (23.2% of the cost of the project.). This $3.58 million would have covered all the work that was necessary to preserve reliability, including the normally-scheduled overhaul, the replacement of some blades, and the *replacement of the inner casing of the HP turbine*. (Sierra Club, pages 11 and 12, emphasis added.)

Sierra Club's argument contains several errors. First, the actual 100% Share cost of the Unit 5 project was $13.473 million, not the $15.45 million originally estimated. Second, the $13.473 million project included replacement of the HP turbine control system. As noted in the 2005 APS study, the control system was becoming increasingly difficult to maintain, due to its age and because repair parts were no longer available. Control system problems had caused outages prior to 2005, and these problems were expected to cause increasing numbers of outages going forward. But such outages were not SCE's only concern. Losing control of the extremely large turbine, that is driven by 3500 psia, has 1,000 degree steam, and rotates at 3600 rpm, was a very serious concern. It is true that the 2005 APS study provided a "status quo" option, to show how the proposed project (at that time) compared to the immediate costs one would incur if one simply ignored the control system problems and continued to operate. But that comparison did not account for the other, significant risks associated with such loss-of-control events. It would have been highly imprudent to not have replaced the degraded, unreliable control system. The controls replacement accounted for over $3 million of the total project.

Third, and perhaps most importantly, Sierra Club ignores damage discovered when the Unit 5 turbine was subsequently disassembled for the 2008 overhaul (i.e., three years *after* the 2005 APS study referenced by Sierra Club). Upon its 2008 disassembly, it was discovered that the Unit 5 inner shell (i.e., casing) cracking was much worse than previously assumed. See Appendix A. The turbine was at extreme risk of a failure, based on the magnitude of the cracking discovered, and it is very fortunate that the shell did not fail catastrophically prior to the start of the 2008 overhaul. In addition to destroying the HP section (which was already scheduled for replacement), such catastrophic failure on an inner shell could have also severely damaged the Intermediate Pressure turbine component section. The HP and IP sections are coupled together, and the resulting movement of the HP shaft (from contact from the failed shell) could easily have driven the rotating IP turbine section element into its stationery elements. It could also have damaged the HP generator, potentially severely.

SCE personnel inspected the Unit 5 turbine crack during the 2008 overhaul. SCE was concerned that Unit 4 had experienced essentially the same operating conditions over its life as Unit 5, and could also develop such cracking in the near future. SCE personnel were concerned that the crack could have (at least in part) resulted from the inherent thermal fatigue that occurs during turbine start-up and shut-down events. Thermal fatigue can adversely affect the reliability of power plant steel components, such as turbine rotors and shells, that operate at high temperature and are exposed to numerous thermal cycles over their service life.

SCE was also well aware of the potentially severe consequences of turbine in-service failures. The year before, in 2007, Unit 5 suffered an unforeseen failure of the Low Pressure B Rotor L-4 stage turbine rotating blades. The failure was limited in scope, and did relatively minor damage to other portions of the turbine. However, it easily could have done more extensive damage, and the fact that it did not could be largely due to the rapid speed at which personnel responded and shut down the unit. The Unit 5 A Rotor was also found to have similar damage.

After repairs were completed to Unit 5, Unit 4 then underwent an unplanned outage for inspection of the area which failed on Unit 5. The same problem was discovered, and the unplanned outage was extended in order to replace the turbine blading that was at risk of failure. The total duration of these 2007 outages was 54 days on Unit 5 and 45 days on Unit 4. The total cost of the unplanned repairs was approximately $4.270 million (SCE Share).[45] Even assuming only $1 million per day in replacement power, the replacement power costs easily exceeded the repair costs.

As indicated above, the Unit 4 HP turbine section project had already been approved by all of the plant co-owners including SCE, and was already underway during these 2007 repairs to the Low Pressure turbine sections of both units, when the severity of the HP inner shell cracking problem became fully known during the 2008 Unit 5 overhaul. All of these events occurred *after* the 2005 APS report was completed, yet Sierra Club relies on this dated report to also find fault with SCE's decisionmaking on the 2010 Unit 4 HP Turbine section replacement, stating:

[45] These 2007 LP turbine blade replacements are among the projects being reviewed in this GRC. See SCE direct testimony, Exhibit SCE-2, Vol. 6, Part 3, pp. 20-21.

> For Unit 4, APS's [2005] analysis showed no forced outages in the future due to the HP turbine even if that turbine was not replaced. All that was needed to prevent future forced outages was to spend $893,791 for the normally-scheduled overhaul of the HP turbine in 2010 and to spend an additional $476,046 for partial replacement of some of the blades in the HP turbine. Therefore, SCE incorrectly claims that it was necessary to spend $16.15 million on the replacement project in order to keep the HP turbine from degrading the reliability of the unit for during the next five years. In fact, that same goal could have been achieved by spending $1.37 million (8.5% of the cost of the project). Most of the expected benefit of the project came from increases in the efficiency of the unit, increases in the electric output of the unit, and reductions in the long-term maintenance costs of the unit. (Sierra Club, page 11.)

Once again, Sierra Club makes several errors. First, the actual 100% Share cost of the Unit 4 project was $13.843 million, not $16.15 million. Second, the Unit 4 project also included replacement of the HP turbine control system, which was degraded and had caused lost generation in the past, and was expected to continue to do so at an increasing rate in the future if not replaced. Sierra Club's cost figures do not include this portion of the project. Third, Sierra Club falsely assigns to SCE the rationale of APS in proposing the project to the other owners in 2005. APS's 2005 predictions regarding improved fuel efficiency and reduced maintenance were *not* SCE's primary rationale for including this project in our 2012 GRC.

As Sierra Club states, SCE's primary reason to continue forward with this project was to assure turbine reliability as we approached the Unit 4 overhaul in early-2010, prepared for our 2012 GRC, and awaited the Commission's decision on our Petition to Modify the EPS for Four Corners. SCE was specifically well aware of four issues related to this project at the time of the 2010 Unit 4 overhaul:

- In 2007 Unit 5 experienced an unforeseen turbine failure costing millions of dollars to repair, incurring an unplanned outage lasting weeks, and perhaps narrowly avoiding more extensive damage.
- In 2007, Unit 4 was inspected for this same previously-unforeseen damage, and it was found.
- In 2008 the Unit 5 turbine crack was found to be much worse than previously assumed.
- Over its life, Unit 4 had been subjected to essentially the same service conditions as Unit 5, and SCE was concerned that cracking could also develop in the Unit 4 HP turbine section in the near future.

As stated in our direct testimony, SCE's concern was reliability and minimizing total costs. Completing the Unit 4 HP Turbine Section replacement project was the best option going forward. Reversing course, and attempting to cancel the replacement turbine section that was already on order (at a uncertain cost that would likely be determined only after a contentious negotiation with the turbine section supplier), and then ordering original replacement turbine blading and an inner shell, would likely have increased costs, not reduced them.

SCE was certainly aware that, as explained in the APS 2005 report, the HP Turbine Section replacement projects were also forecast to reduce future maintenance, and improve fuel economy and increase MW output through higher turbine efficiency. Indeed, we discuss those benefits in our direct testimony:

> Since the completion of the Unit 5 major overhaul in 2008, the net output of Unit 5, when operating at full load, has averaged approximately 770 MW. This primarily reflects the partial replacement of the high pressure (HP) section of the steam turbine during the overhaul. This replacement was needed to sustain plant reliability as the original HP turbine inner shell section was badly degraded and at risk of catastrophic failure. The replacement HP components are of a more modern design and are able to generate a higher MW output at the same coal fuel and steam flow rates. Unit 4 underwent this same replacement during its 2010 overhaul. (SCE-2, Vol. 6, Part 1, page 6.)
>
> Since the time Four Corners was constructed, the technology and design of these machines 16 has advanced. These advancements result in improved machine efficiency. This efficiency improvement provides a decrease in fuel consumption for the same level of power output. (SCE-2, Vol. 6, Part 2, page 25.)
>
> Also included is a new solid particle erosion (SPE) resistant single flow nozzle, replacement of the mechanical hydraulic control system, and control valves modification to allow full-arc steam admission. Full-arc admission reduces the level of thermal fatigue the turbine experiences on start-up, which should help reduce future overhaul costs later in the turbine's life. (SCE-2, Vol. 6, Part 2, page 25.)

As Sierra Club notes, these benefits were quantified in the 2005 APS economic analysis for the projects, but were not included in SCE's economic analysis for the Unit 4 project in this GRC.[46] However, this is simply because, as stated above, these additional benefits were not SCE's primary reason for approving, and then completing, the project. SCE's primary concern was to sustain reliability, including reliability concerns due to the degraded original turbine control system. The fact that APS's 2005 report focused on these other issues does not mean that the turbine shell and blade failure reliability concerns did not exist. These concerns most certainly did exist. The additional information revealed during 2007 and 2008, discussed above, reinforced to SCE the importance of turbine reliability, the high costs (potentially extremely high costs) of turbine in-service failures, and the prudency of avoiding them to the extent practical.

It is also worth noting that the Unit 4 HP turbine section replacement is not the only turbine component replacement completed during the 2010 overhaul. The overhaul also included replacement of the LP turbine, B Rotor, 2nd stage rotating blades, and a portion of the IP turbine blades. Turbine replacement projects are generally planned several months in advance of the routine major overhauls, so

[46] Testimony of Robert Koppe on behalf of Sierra Club, p. 11.

that parts procurement and other overhaul planning activities can be performed. The determination of the precise scope of each turbine component replacement is based on the known extent of the degradation, and the estimated additional degradation that will occur until the major overhaul is undertaken. This, in turn, reflects the judgment and experience of the plant engineers and managers who are planning the overhaul. Because of the potentially catastrophic consequences of a major turbine in-service failure, it is prudent and reasonable that these personnel exercise an appropriate level of conservatism when estimating how much longer to operate a particular part of the turbine before replacing that part. In this case, given that there were several issues of concern, it was decided that the best option was to replace the entire HP turbine component section, rather than to continue to use a piecemeal approach in replacing the degraded parts.

Finally, Sierra Club also claims that the HP Turbine Section replacement projects "each included $1,000,000 to provide capacitors that would compensate for a reduction in the effect of power factor in the generators."[47] Once again, Sierra Club erroneously assumes that the 2005 APS report provides an exhaustive discussion all of the issues surrounding these projects. This is simply not the case. The actual project work continued for five more years after the report was issued. The capacitors referenced by Sierra Club have not been procured or installed, and are not a part of this GRC.[48]

This concludes SCE's detailed rebuttal concerning the four types of replacement projects specifically challenged by Sierra Club. In the next chapter, we explain that Sierra Club's generic claims are equally false concerning other types of equipment replacement projects.

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[47] Testimony of Robert Koppe on behalf of Sierra Club, p. 16.

[48] Even if the capacitors had been included, SCE disagrees the inclusion would have violated the EPS or D.10-10-016. Power plants are required to operate at the power factor directed by the grid operator. If grid circumstances change prior to end of SCE's plant participation, such that the power factor of Four Corners must be altered in a manner which reduces production, and if the purchase and installation of capacitors is more economic compared to reducing power plant MW output for SCE's remaining participation, SCE does not agree with Sierra Club's assertion that the installation would violate the EPS and D.10-10-016.

XIII.

SIERRA CLUB'S CLAIM THAT MOST WORN-OUT EQUIPMENT CAN BE REPAIRED, RATHER THAN REPLACED, IGNORES SCE'S DIRECT TESTIMONY AND SUPPORTING WORKPAPERS EXPLAINING WHY REPAIR IS NOT FEASIBLE

Sierra Club's testimony primarily focuses on the large (i.e., projects costing over $1 million), reliability-driven capital projects that SCE completed during 2007-2011, or forecast to complete during 2012-2014. These projects are summarized in Table XIII-7 below.

Table XIII-7
Reliability Projects Costing Over $1 Million Each
$1,000 – Nominal – SCE Share

No. of Projects	Reliability Projects > $1 Million	SCE Share
7	Boiler Tube Section Replacements	30,021
1	HP Feedwater Heater Repl, Unit 5	1,920
3	GSU Transformer Replacements	6,490
1	HP Turbine & Controls Repl, Unit 4	6,645
12	SUB-TOTAL, Directly Discussed by Sierra Club	45,076
2	2007 Unforeseen LP Turbine Blade Repairs	4,270
2	1AA Transformer Bank Replacements	5,332
3	Generator Field and Stator Rewinds	7,054
1	Boiler Combustion Instrumentation Repl, Unit 5	1,920
2	Air Preheater Basket Replacements	5,026
1	Stack Liner Installation, Unit 5	2,000
11	SUB-TOTAL, Other Large Reliability Projects	25,602
23	TOTAL	70,678

Sierra Club's main argument appears to be that there are other, lower cost options to replacement. Sierra Club erroneously claims that SCE did not consider such options, stating:

> For each capital project, SCE compares the alternative of complete replacement with the alternative of simply fixing failures. It never considers more nuanced alternatives such as extended maintenance or partial replacement, even though such alternatives would probably be more appropriate if a unit were going to be retired in five years or less. Extended maintenance or partial replacement would generally be less expensive than complete replacement and would minimize the amount of money committed to the units. (Sierra Club, page 4.)

In the preceding chapters we explained that SCE has been performing weld repairs to the boiler nose tubes to delay the replacement of that section of the boiler. We explained that such stop-gap repairs cannot be performed indefinitely, and so we forecast the boiler nose replacement for 2014. We explained that there are no options for the other areas of degraded boiler tubing, other than to replace the degraded areas (as reflected in our GRC forecast) or to incur an increasing number of boiler tube leak outages as those areas continue to degrade. We explained the high cost of such outages, compared to the cost of replacing the degrading tubing in a single overhaul outage.

In the preceding chapters, we explained that we do perform partial replacement of feedwater heater components (e.g., replacement of just the shell), in those circumstances where such partial replacement is the most practical and cost effective option. We explained that there are no "extended maintenance options" for addressing degraded feedwater heaters. We showed that Sierra Club's proposal to buy a single spare unit to address three degraded GSU transformers makes no sense, because the transformers on Unit 4 and Unit 5 are not identical and are not interchangeable. We explained that, like many other major equipment items (such as turbines), purposefully running a GSU transformer to failure would be unsafe and highly imprudent because of the collateral damage that could result. We showed that even Sierra Club agrees that to do so would be imprudent. We then explained that the Unit 4 HP turbine section replacement project was the most appropriate option available. In this chapter we explain why the remainder of SCE's forecast for large, reliability-driven projects also reflects the most cost effective, practical option available, starting with the LP Turbine Blade Repairs.

In Chapter XII above, and in our direct testimony, we explained the failures and damage found on the Units 4&5 Low Pressure turbines during 2007.[49] The damage was precipitated by cracking of the disc, where the blades attach to the disc. The engineers and managers who inspected the damage were certain that a catastrophic failure of the turbine would result if the damage was not repaired. One option was to completely disassemble the turbine rotors and replace the damaged discs. However, it was determined that the damage could be machined out, and the damaged blades replaced with new blades having a longer attachment shank, at less total cost (i.e., including the cost of extending the outage and purchasing replacement power). This repair option was selected and the units were returned to service. Sierra Club provides no specific discussion regarding any other hypothetical options that were available to SCE to address this damage.

In our direct testimony, we explained that all four of the 1AA Bank transformers are degraded and need to be replaced.[50] These transformers operate at 345 kV / 500 kV. As with the GSU transformers, the replacement of these four transformers began in 2010 and is forecast to be completed in 2011. As with the GSU transformers, it would be highly imprudent to purposefully operate these

[49] Exhibit SCE-2, Vol. 6, Part 3, pp. 20-21.

[50] Exhibit SCE-2, Vol. 6, Part 2, pp. 23-34.

large, high voltage transformers to failure. The most practical, cost effective and safe option is to replace them as scheduled.

During major turbine generator overhauls, it is not uncommon to rewind generator stators and fields, because of normal electrical insulation degradation from many years of service or for other similar reasons.[51] Unit 4 and Unit 5 each have two generators (i.e., a high pressure and a low pressure generator), and combined, Units 4&5 have four generator rotors and four generator stators. In this GRC, three of these components are being rewound. In our direct testimony, we explained the specific damage noted in each of the three cases and the likely consequences of not making the needed repairs.[52] These consequences include in-service failure. A generator in-service failure can cause a fire and damage other equipment, with a resulting repair outage that can take months to complete, as occurred at SCE's Big Creek Powerhouse 3 Unit 1 generator on December 14, 2008.[53] It would be highly imprudent to purposefully operate these large, high voltage generators to failure. The most practical, cost effective and safe option is to rewind these generator components as scheduled. Finally, it should be noted that a generator rewind *is* a repair; SCE is not proposing to *replace* the generators. Sierra Club provides no specific discussion regarding any other hypothetical options that could be conducted in lieu of the needed generator rewinds.

Boiler combustion instrumentation must be fully functional in order to assure safe and reliable boiler operations. As SCE explained in direct testimony, faulty instrumentation can result in the control system or the plant operator performing an incorrect operation that could trip the unit off line or even damage the boiler.[54] As SCE also explained, the Unit 5 instrumentation is degraded, and repair parts are becoming increasingly difficult to obtain. Replacement of this instrumentation is the most practical, cost effective and safe option available. Sierra Club provides no specific discussion regarding any other hypothetical options that could be conducted in lieu of replacing this instrumentation.

It is common to replace degraded air preheater baskets during major overhauls. The boiler combustion air must be preheated before being admitted to the furnace, in order to assure safe coal

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51 The field (or rotor) is an electro-magnet that is driven by the steam turbine. It rotates inside of the generator stator, and the rotation of the field induces current and power flow inside of the stator electrical windings.

52 Exhibit SCE-2, Vol. 6, Part 2, pp. 20, 27 and 30-31.

53 In that event, a high voltage switch also faulted and caught fire. It is believed that the electrical fault initiated in the switch and propagated to the generator, which then also faulted and caught fire. However, the site of fault initiation cannot be determined with certainty, and it is possible that the fault could have originated in the generator.

54 Exhibit SCE-2, Vol. 6, Part 2, p. 27.

combustion. As SCE explained in direct testimony, the elements are constructed from thin gauge steel sheets that deteriorate over time.[55] This causes loss of fuel efficiency, and parts of the degraded baskets can break off and damage other equipment. If not repaired, the degradation will worsen and eventually the degraded baskets would require the boiler to be shut down. There is no practical means to un-stack the basket elements, and reuse the thinned, fouled, corroded sheets of steel from which the baskets are constructed. Replacing degraded air preheater baskets is a normal maintenance routine at steam power plants. This job *is* a repair; SCE is not proposing to *replace* the entire air preheaters. Sierra Club provides no specific discussion regarding any other hypothetical options that could be conducted in lieu of replacing degraded air preheater baskets.

Degradation of the Unit 5 flue gas exhaust stack must be addressed or it will eventually pose a risk to plant reliability and safety. As explained in SCE's direct testimony, repairs are planned for the 2014 overhaul, which consist of installation of a block liner to prevent further deterioration. Based on the estimated rate of further degradation, it is believed that the 2014 overhaul is the appropriate time to make the repairs. This job *is* a repair; SCE is not proposing to *replace* the entire stack. Sierra Club provides no specific discussion regarding any other hypothetical options that could be conducted in lieu of repairing a degraded stack. SCE does not agree that these kinds of needed repairs to plant structures can be indefinitely postponed, as Sierra Club apparently erroneously believes.

SCE's workpapers to our direct testimony discuss the many similar issues regarding the numerous projects in this GRC that cost less than $1 million each. For example, there are several control system and instrumentation replacement projects where replacement parts are no longer available or becoming difficult to obtain. Other projects involve selective replacement of degraded electrical cables, switchgear and other devices. Also included are projects to assure communications devices, tools, vehicles and similar items are replaced as they wear out, so that plant operations can continue in a reliable and cost effective manner for the remaining duration of SCE's participation. Sierra Club provides no specific discussion regarding any other hypothetical options that could be conducted in lieu of these smaller capital projects. In all cases, SCE has worked with APS and the other co-owners to determine and proceed forward with the most practical and cost effective option.

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[55] Exhibit SCE-2, Vol. 6, Part 2, pp. 21 and 31-32,

XIV.

SCE'S ECONOMIC ANALYSIS ASSUMPTIONS ARE REASONABLE, AND ALL PROJECTS COMPLETED OR FORECAST TO BE COMPLETED DURING OR BEFORE 2012 REMAIN ECONOMIC UNDER A WIDE RANGE OF ASSUMPTIONS

Sierra Club argues that SCE overstates the reliability and replacement power cost impacts of the large reliability-driven projects, and that the expenditures are therefore not necessary. SCE disagrees with these assertions. SCE believes that the power cost forecasts used in our analysis are reasonable for estimating the costs and benefits of these projects. SCE provided to Sierra Club in response to a Data Request the basis of SCE's replacement power $/MWH assumptions.[56] SCE agrees that *recent* prices have been lower than those forecast, as this forecast was prepared when power costs were higher. However, it is not unlikely that prices will return to the levels assumed in our original economic analysis.

Nevertheless, SCE conducted additional economic analyses which demonstrate that the projects are cost effective even assuming drastically lower future replacement power costs than those originally forecast by SCE. Specifically, in order to demonstrate their cost effectiveness over a wide range of assumptions, SCE analyzed the projects using the extreme assumption that our original analyses overstate future replacement power costs by 50%. Copies of these alternative analyses are included in the appendices to this rebuttal. See Appendix C.

These alternative analyses show that, by 2016 year end or sooner all but six “reliability” projects provide customer benefits that exceed project costs.[57] Likewise, the projects are economic under a wide range of assumptions regarding their reliability impact. SCE has already extensively explained the reason for and the basis of our 2012-2014 capital expenditure forecast, and these alternative economic analyses fully support that basis.

In Chapters III and V we explained that underlying basis of our assumptions regarding the increased number of outages that would have occurred (or will occur in the future) if the four kinds of projects specifically discussed by Sierra Club had been or are canceled. These assumptions are based on the degraded condition of the equipment targeted for replacement at the time of our analysis, our forecast of additional degradation in the future based on our prior experience with similar power plant

[56] A copy of this data request is included in Appendix C to this rebuttal.

[57] These six projects (totaling $4.3 million, SCE Share) break even during 2017-2019 and are needed for safety or other reasons in addition to avoiding outage replacement power costs.

equipment, and our estimate of the number and duration of outages that the degraded equipment will cause if not replaced. It is not possible to perfectly forecast such future events.

Sierra Club appears to seek complex paper studies showing the probabilities of in-service failure for different kinds of degraded major equipment items. But even if SCE had conducted such studies, they would still just be a prediction, based on somewhat limited actual experience. Because of the inherent dangers and high costs involved, power plant managers simply do not purposely run major equipment to failure in the reckless manner suggested by Sierra Club. Rather, such forecasts rely heavily on the experience of the professional power plant personnel, who have studied a sufficient number of unplanned failures to learn the warning signs and watch for them. It is these professionals who provided these assumptions, based on their experience.

Sierra Club argues that these assumptions are over-stated, and the plant performance would not significantly degrade without them. Sierra Club also argues that these projects will improve reliability. However, in Chapter VI we explained that actual recorded Units 4&5 reliability from 2000 to 2010 was stable. We showed that there is no trend that in any way supports Sierra Club's assertion that the projects will increase reliability rather than simply sustaining it.

With a few scant exceptions, Sierra Club does not provide any evidence countering the reasonableness of SCE's assumptions regarding the reliability impact of the projects. Rather, Sierra Club simply lifts a few selective quotations from the large volume of information provided to them through discovery, that pertain to just a few projects, and then attempts to draw sweeping conclusions applicable to all projects. Even in those instances where Sierra Club provides specific information, herein SCE has shown that this information cited by Sierra Club does not change our conclusion regarding the necessity of the project.

As explained in our direct testimony, and then expanded upon in this rebuttal, by their nature these economic analyses are not comprehensive. They do not fully account for the risks of ignoring a powerplant's maintenance requirements. When major equipment items fail in service, such as those at issue here, other parts of the plant can be damaged. Plant operators do not, and should not, make maintenance decisions based solely on these kinds of summary-level economic analyses. Power plant managers do not purposefully operate degraded transformers to failure given the fire risks and widespread electrical damage that can be caused by such failures. Damaged boiler tube sections must be replaced when there are no other practical alternatives, other than to experience an increasing number of tube leak outages. Degraded feedwater heaters must be replaced, or costs will be incurred because of the resulting reliability and fuel efficiency impacts, and the turbine will be exposed to the increased risk of extensive damage from a water induction event. Damaged turbine components must be replaced during routine major overhauls, or the risk of catastrophic failure is increased, and the specific work scopes of these replacements should appropriately support the goal of minimizing total plant costs.

SCE's economic analyses are completely appropriate for the purpose of gaging project costs and benefits, and as required to demonstrate project reasonableness. SCE and APS personnel used their experience and exercised appropriate judgment to formulate assumptions regarding the consequences that would be incurred were the projects not performed. We showed the financial impact using a replacement power cost forecast that was reasonable at the time it was prepared. We then conducted additional analysis showing that essentially all projects remain economic, even assuming the replacement power cost forecast is over-stated by 50%. Sierra Club's arguments to the contrary should be rejected. SCE's past capital expenditures should be approved, and SCE's forecast expenditures should be adopted as a reasonable basis for ratemaking should the proposed sale be delayed, or fail to successfully close. Should the sale not close, these 2012-2014 expenditures will be needed to assure safe and reliable operation of Units 4&5 for the remaining duration of SCE's participation, until that participation terminates by executing a replacement sale or through some other manner.

Southern California Edison
Four Corners 851 Application A.10-11-010

DATA REQUEST SET A.10-11-010 Energy Division-SCE-001

To: ENERGY DIVISION
Prepared by: Sumner J. Koch
Title: Sr Atty
Dated: 12/21/2011

Question 03:

Please provide contact information for an appropriate contact at APS. The CPUC intends to inquire whether APS has stated (or is willing to state) definitively and in writing that it will be shutting down Units 1-3 at the Four Corners Generating Station, and whether a certain date has been established for the closure of these three units.

Response to Question 03:

The requested APS contact information is: Mr. David Hansen, APS Vice President of Fossil Operations, phone no. 602-250-4402.

APS's November 22, 2010, Application to the Arizona Corporation Commission (ACC) for authorization to purchase SCE's Four Corners interest includes discussion of APS's intention to shut down Four Corners Units 1-3 following APS's acquisition of the SCE share of Units 4-5. The Application is available at the link below, and also through the ACC website (www.azcc.gov) by searching the website's "eDocket" for the Application's docket number, E-01345A-10-0474.

http://images.edocket.azcc.gov/docketpdf/0000120291.pdf

Please refer especially to the following pages of the APS Application and its supporting testimony:

Application, at pp. 3-4, 9, 12-14, 20-22, 26-27, 28-32.
Direct Testimony of Mark A. Schiavoni, at p. 6.
Direct Testimony of Patrick Dinkel, at pp. 2, 5-7.
Direct Testimony of Jeffrey B. Guldner, at p. 9.

Four Corners Negative Declaration
Greenhouse Gas Emissions Estimation Technique (EET) for Gas-Fired Generation

Natural gas combustion CO_2 equivalents (CO_2 eqv) are based on greenhouse gas (GHG) emission factors and Intergovernmental Panel on Climate Change (IPCC) Global Warming Potentials (GWPs) contained in Appendix C of the California Climate Action Registry (CCAR) General Reporting Protocol (GRP), Version 3.1, January 2009.

To obtain CO_2 eqv, emission factors for combustion byproduct GHGs carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) in units of kilograms per million British Thermal Units (kg/mmBTU) are multiplied by their respective GWPs and then summed, as shown in the following table. To convert from kg/mmBTU to lbs/mmBTU, the result is multiplied by 2.2046 lb/kg.

Natural Gas GHG Emission Factors			
GHGs	**kg/mmBTU**	**GWP**	**CO_2 eqv**
CO_2	53.06	1	53.060
CH_4	0.001	21	0.021
N_2O	0.0001	310	0.031
Total, kg CO_2 eqv / mmBTU			53.112
Emission Factor, lb CO_2 eqv / mmBTU			117.091

To obtain the GHG (CO_2 eqv) emission rate for gas-fired electric power generation using the GHG emission factor of 117.09 lb/mmBTU calculated above, the heat rate of a power plant (generating unit) must be known. Heat rate is the amount of heat, measured in BTUs, needed to generate one kilowatt-hour (kw-hr) of electricity. A BTU is defined as the amount of heat required to raise one pound of water one degree Fahrenheit in temperature (one cubic foot of natural gas releases approximately 1,020 BTUs when combusted, according to the EPA). Heat rate is expressed in units of BTU/kw-hr and is a function of plant efficiency – the more efficient the plant, the lower the heat rate and the lower the GHG emission rate.

- By definition, a 100% efficient energy conversion would have a heat rate of 3,413 BTU/kw-hr (physical constant).

Since no plant is 100% efficient, heat rate is always higher than this value. Actual heat rate is obtained by dividing 3,413 BTU/kw-hr by efficiency expressed as fractional percent. For example, a 35% efficient plant would have a heat rate of 3,413 / 0.35 = 9,750 BTU/kw-hr (rounded to nearest 10).

Since both the GHG emission factor and heat rate are known, the GHG rate in units of lb CO_2 eqv/MW-hr can be calculated as follows:

$$\textbf{(lb } \mathbf{CO_2} \textbf{ eqv/mmBTU) x (BTU/kw-hr) / 1,000 = lb } \mathbf{CO_2} \textbf{ eqv/MW-hr}$$

Using this relationship, typical GHG rates for different types of generation are determined below.

<u>Combined Cycle Generation</u>

New "state-of-the-art" large combined-cycle plants (e.g., Magnolia Power Project, MPP) typically operate at nominal 48% efficiency (i.e., heat rate of 7,110 BTU/kw-hr), which achieves-in-practice a GHG rate of 833 lb CO_2 eqv/MW-hr, as shown below:

Normal Operation (typical base load):
Heat Input (gas turbine) = 1,780 mmBTU/hr
Generators output (gas + steam turbines) = 250 MW
Heat Rate = (1,780/250) x 1,000 = 7,120 BTU/kw-hr
Efficiency = 3,413/7,120 = 0.479 = 48% base load efficiency (rounded)

Peaking Operation (limited by permit condition):
Heat Input (gas turbine + duct burner) = 2,370 mmBTU/hr
Generators output (gas + steam turbines) = 323 MW
Heat Rate = (2,370/323) x 1,000 = 7,337 BTU/kw-hr
Efficiency = 3,413/7,337 = 0.465 = 47% peaking efficiency (rounded)

Greenhouse Gas Rate (typical base load):
3,413 / 0.48 = 7,110 BTU/kw-hr
117.09 lb CO_2 eqv/mmBTU x 7,110 BTU/kw-hr / 1,000 = **833 lb CO_2 eqv/MW-hr**

CARB Default Generation

CARB's default value of 959 lb CO_2 eqv/MW-hr is equivalent to 41.7% efficiency (i.e., heat rate of 8,190 BTU/kw-hr), as shown below:

(959 lb/MW-hr) / (117.09 lb/mmBTU) x 1,000 = 8,190 BTU/kw-hr
3,413 / 8,190 = 0.417 = **41.7% efficiency**

SB 1368 Emission Performance Standard (EPS) Generation

CPUC Decision No. 07-01-039 defines the interim standard of 1,100 lb CO_2 eqv/MW-hr which would be equivalent to 36.3% efficiency (i.e., heat rate of 9,390 BTU/kw-hr), as shown below:

(1,100 lb/MW-hr) / (117.09 lb/mmBTU) x 1,000 = 9,394 BTU/kw-hr
3,413 / 9,394 = 0.363 = **36.3% efficiency**

In the Decision, particularly on page 8, this is explained as reflecting gas-fired combined-cycle generation but also intended to allow for a considerable range of such gas-fired combined-cycle units, of varying ages and operating in a range of environments and subject to a range of permit constraints.

Legacy Steam Turbine and Simple-Cycle Gas Turbine Generation

A legacy GHG rate of 1,175 lb/MW-hr would be equivalent to 34% average efficiency (i.e., average heat rate of 10,040 BTU/kw-hr). This represents a conservative mix of typical gas-fired generation resources, both conventional steam and simple-cycle peaking units, but excluding combined-cycle, as representative of generating units which have been in service for many years. Determination of mixed (composite) efficiency is shown in the following table:

Estimated Legacy Generation Efficiency						
Unit Type	**Unit Size**	**Plant Name**	**Heat Input**	**Output**	**Heat Rate**	**Efficiency**
			mmBTU/hr	**MW**	**BTU/kw-hr**	**percent**
Simple Cycle	Peaker	Lake	450	46	9,783	34.9%
Steam Turbine	Small	Olive	605	55	11,000	31.0%
Steam Turbine	Medium	Mandalay	1,990	215	9,256	36.9%
Steam Turbine	Large	Ormond	7,400	750	9,867	34.6%
Average Legacy Efficiency						**34%**

Using the average 34% efficiency determined above, the legacy GHG rate is estimated below:

Greenhouse Gas Rate (estimated for typical legacy plants):
3,413 / 0.34 = 10,040 BTU/kw-hr
117.09 lb CO_2 eqv/mmBTU x 10,040 BTU/kw-hr / 1,000 = **1,175 lb CO_2 eqv/MW-hr**

This GHG rate is representative of the units that APS would be most likely to curtail and replace with its added generation from Four Corners following the Four Corners transaction.