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| Docket | : | A.16-04-001 |
| Exhibit Number | : | ORA-1 |
| Commissioner | : | Michel Florio |
| Admin. Law Judge | : | Pat Tsen |
| ORA Project Mgr. | : | Radu Ciupagea |


**OFFICE OF RATEPAYER ADVOCATES**
**CALIFORNIA PUBLIC UTILITIES COMMISSION**


# REPORT ON SOUTHERN CALIFORNIA EDISON'S ENERGY RESOURCE RECOVERY ACCOUNT COMPLIANCE APPLICATION FOR RECORD PERIOD 2015

## (PUBLIC VERSION)


San Francisco, California
September 15, 2016

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# MEMORANDUM

This report was prepared by the Office of Ratepayer Advocates (ORA) of the California Public Utilities Commission (CPUC or Commission) on Southern California Edison's (SCE) Energy Resource Recovery Account (ERRA) Compliance Application for the 2015 Record Period. In this docket, SCE requests the Commission to find that during the Record Period: (1) its fuel and purchased power expenses complied with SCE's Commission-approved procurement plan and were recorded accurately; (2) its contract administration, management of utility-retained generation ("URG'), dispatch of generation resources, and related spot market transactions complied with Standard of Conduct Four ("SOC 4")[1] in SCE's procurement plan; and (3) all other SCE activities subject to Commission review in this ERRA Review proceeding complied with applicable Commission decisions and resolutions.[2]

ORA presents its analysis and recommendations associated with SCE's request. ORA reviewed SCE's testimony, work papers, responses to data requests, and presentations. It also had several in-person meetings and follow up telephone conversations with SCE staff regarding its testimony, work papers, responses and presentations.

ORA's witnesses' prepared qualifications are contained in Appendix A of this report.

The issues that ORA reviewed are listed below and summarized in Chapter 1.

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[1] See D.02-10-062, p. 52 (Oct. 24, 2002) [hereinafter "October Decision"] (defining the Standards of Conduct applicable to ERRA).

[2] Application of Southern California Edison Company (U338E) for a Commission Finding that its Procurement-Related and Other Operations for the Record Period January 1 Through December 31, 2015 Complied with its Adopted Procurement Plan; for Verification of its Entries in the Energy Resource Recovery Account and Other Regulatory Accounts; and for Refund of $0.082 Million Recorded in Two Memorandum Accounts, pp. 1–2 (Apr. 1, 2016) (Application (A.) 16-04-001) [hereinafter "SCE's Application"].

## **List of ORA Witnesses and Respective Chapters**

| Chapter Number | Description | Witness |
|---|---|---|
| 1 | Introduction | Radu Ciupagea |
| 2 | Least Cost Dispatch | Mea Halperin |
| 3 | Utility-Owned Generation -Hydroelectric | Michael Yeo |
| 4 | Utility-Owned Generation – Natural Gas | Michael Yeo |
| 5 | Contract Administration and Costs | Mea Halperin |
| 6 | Balancing and Memorandum Accounts | Brian Lui and Grant Novack |
| 7 | Greenhouse-Gas Compliance | Tom Gariffo |

# CHAPTER 1: INTRODUCTION

(Witness: Radu Ciupagea)

## I. EXECUTIVE SUMMARY

This testimony includes results of the Office of Ratepayers Advocates' (ORA's) review of Southern California Edison's (SCE) Energy Resource Recovery Account (ERRA) Compliance Application for the period from January 1, 2015 to December 31, 2015 (Record Period). SCE filed this application pursuant to Decision (D.) 02-10-062, in which the Commission required certain utility procurement activities to be reviewed annually in an ERRA proceeding.

According to the Commission, the purpose of the ERRA annual review, in general, is to:

(1) review whether SCE's energy procurement activities were consistent with the least cost dispatch principles set forth in Standard of Conduct 4 (SOC 4);[3]

(2) determine whether SCE accurately recorded procurement expenses that are eligible to be recovered through the ERRA balancing account;

(3) review entries in the ERRA balancing account to ensure that they are accurate and consistent with Commission decisions; and

(4) determine whether SCE prudently administered its Qualifying Facilities (QF) contracts and non-QF contracts, and whether the operation of its utility-owned generation units, including maintenance outages, was reasonable.[4]

SCE filed its application on April 1, 2016, requesting Commission approval of activities that occurred during the 2015 Record Period. ORA's review of SCE's application is predominantly focused on the 2015 Record Period and includes: least-cost dispatch (LCD) of electric generation resources, including demand response, utility

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[3] D.02-10-062, p. 52 (Oct. 24, 2002) ("[U]tilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner.")

[4] D.11-10-002, p. 3 of Appendix.

owned generation (UOG) hydroelectric operations, UOG natural gas, solar photovoltaic program (SPVP), fuel expenses and operations of nuclear generation resources, contract administration,[5] and an audit of the balancing account entries.

In this application, SCE requests review of the revenue collected [$4.903 billion] and procurement expenses [$4.248 billion] in the ERRA account as of December 31, 2015.

SCE's Application requests approval to refund to customers approximately $0.082 million due to a net over-collection in the following two Commission-authorized regulatory Memorandum Accounts:

i) Renewables Portfolio Standard Costs Memorandum Account; and

ii) Project Development Division Memorandum Account.

In addition, SCE seeks Commission review of the operation of the Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA) for the 2015 Record Period.

The scope of ORA's review in this proceeding included ERRA and Non-ERRA accounts, as well as audits of the various account entries.

## II. SUMMARY OF OBSERVATIONS AND RECOMMENDATIONS

The following is a summary of the observations and recommendations ORA witnesses describe in subsequent chapters:

**Chapter 2: Least Cost Dispatch (Mea Halperin)**

**A.** Assessment of Overall Forecasting Accuracy

ORA recommends the Commission order SCE to:

- provide either additional metrics or a supplemental narrative to the workpapers summarizing the data, defining terms and

[5] Contract administration includes a review of Department of Water Resources (DWR) contracts, existing QF contracts, Combined Heat and Power (CHP) contracts, inter-utility contracts, conventional energy and natural gas contracts, and renewable contracts. ORA also reviewed contract administration for Demand Response Aggregator Managed Portfolio (AMP) agreements.

acronyms, and indicating what constitutes “normal” or “accurate.”

- undergo an independent review, by an outside party, of its processes for forecasting day-ahead load and prices, including an evaluation of whether SCE revises and updates its strategies based on above-normal deviations. The plans for this review must be in place by the time SCE files its next ERRA compliance application.

**B.** Assessment of Management of Thermal Resources

ORA recommends the Commission order:

- [redacted]. Because the reason for the commitment costs errors for 2012 through 2014 was only reported in the Record Period 2015 filing, ORA had new reason to analyze the cost impacts incurred as a result of these errors. Upon doing so, ORA found that the errors are unreasonable and the fact that SCE did not notice or report them until 2016 demonstrates a lack of due diligence.

- SCE to improve its bidding activity reporting in accordance with the Decision (D.) 15-05-007 and clearly provide data for the number of times resources were not bid into CAISO markets when available (even if it was zero times) and the percentage of times incremental energy was not awarded when the incremental bid cost was below the Locational Marginal Pricing (LMP) (even when 0% or if the added start-up and minimum load costs make dispatch uneconomic).

**C.** Assessment of Management of Hydroelectric Resources

ORA recommends the Commission order SCE to:

- improve its hydro reporting in accordance with D. 15-05-007 and clearly provide data for the bidding and dispatch during the 100 highest LMPs of the year at each resource location as required by that Decision.

- report in the LCD chapter any and all limitations to dispatch of hydro and pumped storage resources – including unavailability due to drought and/or outages – when relevant to hydro least-cost dispatch.

- undergo an independent review by an outside party of its hydro models to determine whether they are reasonable or if SCE could make any improvements. The plans for this review must be in place by the time SCE files its next ERRA compliance application.

**D.** Assessment of Management of Renewable Resources

ORA recommends the Commission order SCE to:

- include, in its future testimony, reporting and quantitative calculations of renewable resource opportunity costs by type (e.g. wind, solar, etc.).
- include, in its future testimony, explanations of energy curtailment, including instances when it is necessary, how the economic decision to curtail a resource is made, the business process for curtailing a resource, and any quantitative metrics associated with this process.

**E.** Assessment of Demand Response Programs

ORA recommends the Commission order SCE to:

- report all of the Demand Response metrics and data relevant to post-CAISO market integration DR dispatch in its testimony and workpapers according to D.15-05-007.
- report any metrics, calculations, evaluations of opportunity costs, bidding activity, and processes associated with the CAISO market integration process that are not required by D.15-05-007 but that explain this process in a way that allows ORA to evaluate compliance with least-cost dispatch principle.

**Chapter 3: Utility - Owned Generation – Hydroelectric (Michael Yeo)**

ORA recommends the Commission order SCE to:

- implement the corrective actions identified in the Root Cause Evaluation Report for the Kern River 3, Unit 1 outage, and
- report those corrective action implementations in the annual ERRA Compliance filing for the 2016 Record Period, and report the effectiveness of those implementations in preventing recurrence in the next ERRA compliance filing

**Chapter 4: Utility-Owned Generation – Natural Gas (Michael Yeo)**

ORA recommends the Commission:

- disallow cost recovery of $107,810 in SCE’s ERRA Balancing Account for the 2015 Record Period because SCE was accountable for the April 26, 2015 Mountain Generating Station Unit 3 outage; and

- order SCE to submit a copy of AM&T's revised testing procedure in the next ERRA Compliance filing for the 2016 Record Period.

**Chapter 5: Contract Administration and Costs (Mea Halperin)**

Based on its review, ORA does not object to:

- SCE's request for approval of the contract amendments resulting in a change in the notional value of the underlying PPA.
- SCE's overall contract administration activities in the Record Period.

However, ORA recommends that in future testimony:

- SCE clearly indicate which items were not previously approved in the Record Period or through any separate decision or resolution, and which items require Commission approval.

**Chapter 6: Balancing and Memorandum Accounts (Brian Lui and Grant Novack)**

ORA concludes that:

- SCE appropriately operated the balancing, memorandum, and tracking accounts during the 2015 Record Period, and that the recorded entries in these accounts were appropriate, correctly stated, and in compliance with applicable Commission decisions.
- SCE's requested total net revenue change is supported and correctly stated. ORA does not object to SCE's request for approval of the $0.082 million net revenue requirement decrease.

**Chapter 7: Greenhouse-Gas Compliance (Tom Gariffo)**

Based on its review, ORA does not object to:

- SCE's request that the Commission find SCE's GHG procurement activity for the 2015 Record Period reasonable and within its procurement authority.

ORA recommends that:

- SCE submit a more detailed filing addressing GHG costs and incorporating indirect GHG compliance costs and procurement in future compliance years

# CHAPTER 2: LEAST COST DISPATCH

(Witness: Mea Halperin)

## I. INTRODUCTION AND SUMMARY

This chapter of testimony reviews Southern California Edison's (SCE) electricity dispatch and demand response (DR) activities for the 2015 Record Period from January 1, 2015 through December 31, 2015 and considers whether SCE met the Commission's least-cost dispatch (LCD) standard. The Office of Ratepayer Advocates (ORA) examined Chapter 2 of SCE's 2015 Energy Resource Recovery Account (ERRA) compliance testimony and submitted workpapers and analyzed data request responses, attended in-person and telephone meetings, and reviewed past ERRA testimony. Both SCE's energy scheduling and demand response dispatch decisions were reviewed using the Commission's LCD standard of review, described below.

## II. FINDINGS AND RECOMMENDATIONS

### A. Assessment of Overall Forecasting Accuracy

- ORA recommends the Commission order SCE to provide either additional metrics or a supplemental narrative to the workpapers summarizing the data, defining terms and acronyms, and indicating what constitutes "normal" or "accurate."
- ORA recommends the Commission order SCE to undergo an independent review, by an outside party, of its processes for forecasting day-ahead load and prices, including an evaluation of whether SCE revises and updates its strategies based on above-normal deviations. The plans for this review must be in place by the time SCE files its next ERRA compliance application.

### B. Assessment of Management of Thermal Resources

- ORA recommends the Commission order a [redacted] Because the reason for the commitment costs errors for 2012 through 2014 was only reported in the Record Period 2015 filing, ORA had new reason to analyze the cost impacts incurred as a result of these errors. Upon doing so, ORA found that the errors are unreasonable and the fact that SCE did not notice or report them until 2016 demonstrates a lack of due diligence.

- ORA recommends the Commission order SCE to improve its bidding activity reporting in accordance with the Decision (D.) 15-05-007 and clearly provide data for the number of times resources were not bid into CAISO markets when available (even if it was zero times) and the percentage of times incremental energy was not awarded when the incremental bid cost was below the Locational Marginal Pricing (LMP) (even when 0% or if the added start-up and minimum load costs make dispatch uneconomic).

C. Assessment of Management of Hydroelectric Resources

- ORA recommends the Commission order SCE to improve its hydro reporting in accordance with D.15-05-007 and clearly provide data for the bidding and dispatch during the 100 highest LMPs of the year at each resource location as required by that Decision.
- ORA recommends the Commission order SCE to report in the LCD chapter any and all limitations to dispatch of hydro and pumped storage resources – including unavailability due to drought and/or outages – when relevant to hydro least-cost dispatch.
- ORA recommends the Commission order SCE to undergo an independent review by an outside party of its hydro models to determine whether they are reasonable or if SCE could make any improvements. The plans for this review must be in place by the time SCE files its next ERRA compliance application.

D. Assessment of Management of Renewable Resources

- ORA recommends the Commission order SCE to include, in its future testimony, reporting and quantitative calculations of renewable resource opportunity costs by type (e.g. wind, solar, etc.).
- ORA recommends the Commission order SCE to include, in its future testimony, explanations of energy curtailment, including instances when it is necessary, how the economic decision to curtail a resource is made, the

business process for curtailing a resource, and any quantitative metrics associated with this process.

E. Assessment of Demand Response Programs

- ORA recommends the Commission order SCE to report all of the Demand Response metrics and data relevant to post-CAISO market integration DR dispatch in its testimony and workpapers according to D.15-05-007.
- ORA recommends the Commission order SCE to report any metrics, calculations, evaluations of opportunity costs, bidding activity, and processes associated with the CAISO market integration process that are not required by D.15-05-007 but that explain this process in a way that allows ORA to evaluate compliance with least-cost dispatch principles.

# III. BACKGROUND

## A. Standard of Conduct for Least-Cost Dispatch and Demand Response

D.02-10-062 instituted rules for the utilities' procurement responsibilities, established ERRA as the cost recovery mechanism for short-term procurement costs, and set minimum standards of behavior.[6] Standard of Conduct #4 (SOC4) states, "The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[7]

The subsequent decision (D.02-12-074) described the utilities' "up-front standard"[8] of least-cost dispatch as a guide for their short-term procurement plans as well as for the Commission to determine compliance. The decision elaborated upon SOC4:

> "Least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services…[P]ure economic dispatch of resources may need to be constrained to satisfy operational, physical, legal, regulatory, environmental,

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[6] D.02-10-062, p. 2.

[7] *Id.*, p. 52.

[8] D.02-12-074, p. 54.

> and safety considerations. The utility bears the burden of proving compliance with the standard set forth in its plan."[9]

**B. Clarification of LCD Expectations Following SCE's 2010 and 2012 Record Period ERRA Compliance Proceedings**

ORA's analysis of each investor-owned utility's (IOU) ERRA 2010 Record Period LCD testimony concluded that the utilities did not achieve least-cost dispatch and recommended disallowances for each utility. The Commission reviewed SCE's LCD showing in Application (A.) 11-04-001 and issued D.13-11-005, which stated that while the Commission would not approve the disallowance recommendation, the showing was below expectations.[10] The decision sought to "ameliorate these shortcomings and provide specific direction to SCE to improve its showings in the future."[11]

In order to improve LCD showings, the decision stated that going forward, SCE must include "precise numerical calculations that either demonstrate that SCE achieved least-cost dispatch during the Record Period, or quantify the amount of overspending by SCE."[12] Additionally, the decision directed the Commission's Energy Division to facilitate a workshop with all IOUs, wherein a set of proposed criteria would be developed for determining what constitutes least-cost dispatch compliance and the methodology required to demonstrate this compliance.[13]

Finally, in response to the 2012 Record Period ERRA reporting, ORA asserted that SCE did not demonstrate that it achieved LCD.[14] The Commission further clarified LCD responsibilities by issuing D.14-05-023 in which it established that, following the Market Redesign Technology Update (MRTU) in 2009, the California Independent

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[9] *Id.*

[10] D.13-11-005, p. 15.

[11] *Id.*, p. 16.

[12] *Id.*, p. 26.

[13] *Id.*

[14] D.14-05-023, p. 9.

System Operator (CAISO) is responsible for dispatching energy generation.[15] In other words, the regulated utilities are responsible for scheduling and bidding, but actual dispatch is performed by the CAISO.

### C. Joint Proposal, Interim Ruling, and Final Decision for A.11-02-011

After the workshops, the utilities and subject matter experts proposed LCD criteria and methodologies and submitted them to the Commission in 2014 as the "Joint Proposal for the Demonstration of Least-cost Dispatch" (Joint Proposal).[16] ORA reviewed the proposal and provided recommendations, but the utilities and ORA disagreed on the format for reporting their Demand Response (DR) programs in ERRA compliance applications.[17]

The Commission issued the "Interim Ruling Providing Guidance for 2014 ERRA Compliance Proceedings," directing the utilities to comply with the uncontested portions of the Joint Proposal, as follows:

> i.) The LCD Proposal shall be modified to include a background summary table in testimony.
>
> ii.) The utilities shall use the 500 instead of 100 highest hourly Locational Marginal Prices in metric 4 of the Joint Proposal.
>
> iii.) The summary reporting of daily self-commitment decisions shall be modified to show both "profit positions" and "loss provisions."
>
> iv.) The utilities shall include a comparison of the accuracy of the utilities' forecast of prices in the day-ahead market compared to actual California Independent System Operator results.[18]

Finally, the Commission's Interim Ruling addressed the dispute between ORA and the utilities by ordering that the utilities show the "metrics for Demand Response" in the

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[15] *Id.*, p. 19.

[16] D.15-05-006, p. 7.

[17] *Id.*, p. 7-11.

[18] *Id.*, p. 12.

format proposed by ORA in ORA's response to the Joint Proposal.[19] The Commission issued a Proposed Decision on April 1, 2015, affirming the guidance and direction stated in the Interim Ruling.[20] D.15-12-015n was approved and finalized on May 7, 2015 and the standards were expanded to apply to all three utilities on December 3, 2015.[21]

### D. Demand Response CAISO Market Integration

In 2013, the Commission instituted Rulemaking (R.) 13-09-011 introducing the goal of integrating demand response resources into the CAISO market. This refers to the process of working with CAISO to convert demand response resources into resources that can be bid into the CAISO market and dispatched when trigger conditions are met. The purpose of the integration would be to "enhance the role of demand response programs in meeting the state's long-term clean energy goals while maintaining system and local reliability."[22] The Rulemaking proposed strategies to "bifurcate" DR resources into demand-side (customer-focused programs) and supply-side (for flexible system resource planning and operational requirements), as well as provide roadmaps for transitioning to this type of program.

The following decision (D.14-03-026) approved the rulemaking and established some guidelines for the transition, including defined parameters for demand- and supply-side resources, division of responsibilities between CAISO and the utilities, and clarified goals for both reducing net demand and providing resource adequacy.[23] The decision also ordered that "operational bifurcation will occur beginning with the 2017 demand response program year."[24]

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[19] *Id.*

[20] *Id.*, p. 13-14.

[21] D.15-12-015, Conclusion of Law 2, p. 6.

[22] R.13-09-011, p. 2.

[23] D.14-03-026, p. 26-27.

[24] *Id.*, p. 28.

## IV. DISCUSSION AND ANALYSIS

ORA's analysis is organized to assess the following elements of SCE's LCD and DR testimony: the accuracy of SCE's overall forecasting accuracy and load bid calculations, dispatch of thermal resources, dispatch of hydro resources, and dispatch of DR programs.

### A. Overall Forecasting Accuracy

#### i. Overview

In order to support its day-ahead market bidding, as well as to inform power and natural gas trading activities, SCE conducts demand (load) and price forecasts. The demand forecast is performed hourly for each operating day and is based on short-term weather and actual hourly-updated load data.[25] The daily price forecast reflects energy demand given market dynamics and data provided from other departments at SCE. SCE then combines the demand and price forecasts to determine market clearing prices and the marginal cost of providing energy, which will inform the price at which a resource is bid into the CAISO's day-ahead market.

The accuracy of SCE's day-ahead forecast can be determined by comparing the load and price forecasts with the actual CAISO load and clearing price to get the average mean absolute percentage error (MAPE), which is a measure of the forecast price deviation from the actual clearing price. These data can be calculated from SCE's workpapers where it compares forecast and actual price[26] and load[27] for the 100 highest energy value days (ranked based on the total cost of the load cleared in the day-ahead market) as well as for every hour of every day of the Record Period. In addition to verifying forecast accuracy, this analysis provides insight into how accurately SCE values its dispatchable resources to ensure that they are bid economically and consistently with least-cost dispatch principles.

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[25] A.16-04-001, Testimony, Chapter II, Part D, Section 2, p. 18.

[26] *Id.*, Chapter II Workpapers, "Price Forecast."

[27] *Id.*, "DLAP Highest 100 Value Days."

### ii. Analysis

Among the 100 highest energy value days, the average MAPE for SCE's price forecast was [redacted] and the median value was [redacted][28] [redacted] Additionally, the maximum MAPE in 2015 was [redacted], while in 2014 the maximum was [redacted]. The average price variance (subtracting the actual market price from the forecast price) in 2015 ranged from [redacted][29]

When comparing SCE's 2015 load forecast with the data from 2014, [redacted] during the 100 highest energy value days. The maximum MAPE in 2015 was [redacted], whereas in 2014 it was [redacted]. The daily sum of total awarded versus actual dispatched load for the 100 highest energy value days in 2015 showed a median variance of [redacted] megawatt-hours (MWh) and a mean of [redacted] MWh, with an overall range of [redacted]. When looking at the variances for each individual hour of the highest energy value days (a data set of 2,400 values), the median variance was [redacted] and mean was [redacted] with a range of [redacted].[30] Again, on their own, these values do not reveal or prove forecast accuracy, so ORA compared the 2015 data with the 2014 showing. In 2014, the daily sum of total awarded versus actual dispatched load for the 100 highest energy value days showed a median variance of [redacted] and a mean of [redacted], with an overall range of [redacted]. When looking at each individual hour of the top 100 energy

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[28] ORA Workpapers, Price Forecast 2014 vs. 2015.

[29] *Id.*

[30] ORA Workpapers, Load Forecast 2014 vs. 2015.

value days, the median variance was [redacted] and mean was [redacted], with an overall range of [redacted].[31] The yearly comparison is illustrated in the tables below.

**Table 2.1: Price Forecast Comparison between 2015 and 2014 Record Periods (Confidential)**

| | | Mean Absolute Percentage Error | | | | Variance | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Data Range | Median | Mean | Max. | Min. | Median | Mean | Max. | Min. |
| 2015 | Top 100 Days | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2014 | Top 100 Days | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2015 | All 365 Days | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2014 | All 365 Days | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

**Table 2.2: Load Forecast Comparison between 2015 and 2014 Record Periods (Confidential)**

| | | Mean Absolute Percentage Error | | | | Variance (in MWh) | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Data Range | Median | Mean | Max. | Min. | Median | Mean | Max. | Min. |
| 2015 | Top 100 Days | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2014 | Top 100 Days | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2015 | All Hours of Top 100 Days | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2014 | All Hours of Top 100 Days | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

### iii. Summary and Recommendations

[redacted]

[31] *Id.*

[redacted] In order for ORA to determine whether SCE's data shows that its forecast is accurate, it is necessary to have a base line or standard of metrics. ORA did not have the resources to analyze and compare SCE's LCD reporting for the 2014 and 2015 Record Periods. Although the workpapers that SCE provided following the Joint Proposal[32] are more thorough, SCE's narrative still does not describe the data or meet the Commission requirement[33] to prove LCD compliance. ORA does not recommend any cost disallowances based on the data but does recommend:

- The Commission order SCE to provide either additional metrics or a supplemental narrative to the workpapers summarizing the data, defining terms and acronyms, and indicating what SCE considers "normal" or "accurate."
- The Commission order SCE to undergo an independent review, by an outside party, of its processes for forecasting day-ahead load and prices, including an evaluation of whether SCE revises and updates its strategies based on above-normal deviations. The plans for this review must be in place by the time SCE files its next ERRA compliance application.

### B. Load Bid Calculations

SCE submits bids for all of its available dispatchable load in the day-ahead market[34] and CAISO dispatches what does not clear in the real-time market. SCE's Default Load Aggregation Point (DLAP) load summary shows the total number of MWh awarded[35] each month in the day-ahead market and actual settled load (based on meter data).[36] Based on these data, [redacted] of SCE's load cleared in the day-ahead market, and each month, [redacted] cleared in the real-time market. [redacted]

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[32] D.15-05-007.

[33] D.02-12-074, p. 54.

[34] A.16-04-001, Testimony, Chapter II, Part D, Section 1, p. 14.

[35] In this context "awarded" refers to energy dispatched by CAISO in the day-ahead market.

[36] A.16-04-001, Chapter II Workpapers, "DLAP Awards-Actuals."

[redacted][37]

This information provides large-scale context for the efficacy of SCE's load bidding strategy. A high proportion of load cleared in the day-ahead market indicates that SCE forecast and procured sufficient energy resources relative to consumer demand, and then appropriately calculated the value of its resources and translated these values into bids that would allow the resources to be economically dispatched.

### C. Management of Thermal Resources

SCE is required to bid its utility-owned and contracted thermal resources at their incremental (marginal) costs, recognizing all operating, regulatory, legal, environmental, and financial obligations and constraints. ORA analyzed the following metrics in order to assess whether SCE managed its thermal resources responsibly, consistent with least-cost principles.

#### i. Commitment Cost Decisions

SCE is required to submit to CAISO its expected costs for starting up resources and running them at their minimum load, also known as commitment costs.[38] CAISO logs this information into its Master File, which is the record of all dispatchable resources' operating parameters and costs, and is used to inform CAISO's dispatch decisions. Utilities can submit proxy bids, which are determined by CAISO and can vary daily based on the cost of natural gas. Alternately, if SCE believes that the proxy bids set by the CAISO do not adequately reflect the true costs of running a resource, like a facility's non-fuel related costs, SCE can use the registered cost option. The registered cost option allows SCE to bid up to 1.5 times the proxy cost, but registered cost bids cannot be updated for 30 days.

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[37] ORA Workpapers, Load Bid Calculations.

[38] Commitment costs are different from incremental bid costs in that they reflect only the cost of starting up and running a resource at its minimum operational load and are for informational purposes. Incremental bids are submitted to the CAISO market for each resource, each hour of every day, and reflect the marginal cost of energy for that resource.

It is important for SCE to choose the correct cost option, allowing its dispatchable resources to be bid as accurately as possible, and to fully capture the resource cost in the bid price. This allows CAISO to optimize the dispatch of all available energy resources based on the lowest possible cost, subject to other constraints.

At the end of 2014, CAISO updated its startup cost calculations to include major maintenance adder costs, which were responsible for some of the variable non-fuel related costs that would be captured in a registered cost bid. In 2015, in implementing this change, CAISO issued the Commitment Cost Enhancement (CCE) initiative, which mandated the use of proxy costs for all non-use limited dispatchable thermal resources.[39] During the 2015 Record Period, SCE submitted registered costs for its use-limited dispatchable thermal resources, and proxy costs for the remainder.[40] Phase Two of the CCE allowed market participants to submit proxy bids for multi-stage generators at up to 1.25 times the CAISO-calculated cost in order to capture the "transition" costs of moving between configurations.[41]

Following CAISO's Commitment Cost Enhancement initiative, [redacted][42] [redacted][43] Cost impacts are calculated by comparing Bid Cost Recovery credits from settlement invoices with the calculations from the corrected commitment costs.[44] SCE

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[39] A.16-04-001, Testimony, Chapter II, Section F, Part 1, p. 22.

[40] *Id.*

[41] *Id.*, p. 22-23.

[42] *Id.*, Chapter II Workpapers, "Section E_Commit Cost."

[43] *Id.*

[44] SCE Response to Data Request 21, Question 1, Part a.

calculates these impacts for the year as a whole in the following year when preparing ERRA testimony.[45]

SCE presented new information in its Record Period 2015 testimony regarding its commitment cost bid errors for not only 2015, but for previous Record Periods as well. While reviewing its Resource Data Template for the 2015 Record Period, SCE discovered that the reason for the incorrect registered commitment cost elections was that it had "misapplied the CAISO cost cap calculation formula when submitting Registered [start-up and minimum load] cost values for its resources."[46] In its Supplemental Direct Testimony, SCE reported that a subsequent investigation revealed that it had made the same error in its commitment cost calculations for Record Periods 2012 through 2014 as well.[47] Additionally, SCE discovered 227 additional commitment cost calculation errors committed in Record Period 2014.[48] At the time SCE filed its Record Period 2012 and 2013 ERRA compliance testimony, it was not required for the utilities to provide numerical data on their commitment cost elections, but the written testimony from these two years does not mention any errors at all in the narrative.[49] The combined cost impact from incorrect commitment cost elections for 2012 through 2014 is [redacted][50]

The information regarding the commitment cost calculation errors for Record Periods 2012 through 2014 was presented to the Commission for the first time in the Supplemental Testimony filed on June 29, 2016 and had not been reported in any previous ERRA compliance filing.[51] The Commission can only approve or disallow costs based on the information available at the time of the ERRA filing. Because the reason for

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[45] SCE Response to Data Request 22, Question 7.

[46] A.16-04-001, Testimony, Chapter II, Part E, p. 21.

[47] *Id.*, Supplemental Direct Testimony, Chapter IV, Part B, p. 18.

[48] *Id.*, Workpapers, "Section E_Commit Cost _SUPP_2012-14".

[49] A.14-04-006, A.13-04-001.

[50] A.16-04-001, Supplemental Direct Testimony, Workpapers, "Section E_Commit Cost _SUPP_2012-14".

[51] SCE Response to Data Request 22, Question 3.

the commitment costs errors for 2012 through 2014 was only reported in the Record Period 2015 filing, ORA had new reason to analyze the cost impacts incurred as a result of these errors. Upon doing so, ORA found that the errors are unreasonable and the fact that SCE did not notice or report them until 2016 demonstrates a lack of due diligence. [redacted]

**ii. Incremental Bid Cost Calculations**

SCE calculates the incremental costs of its resources based on the variable costs associated with increasing or decreasing units of energy. The components that go into these incremental costs include incremental heat rates, variable operating and maintenance costs, greenhouse gas (GHG) costs, CAISO grid maintenance charges, natural gas prices, and any additional natural gas adders.[52] [redacted][53] [redacted] At this time, SCE does not know why these bids were submitted incorrectly, but notes that they are "exploring potential remedies" to prevent this type of data discrepancy for future Record Periods.[54]

By comparison, in 2014, SCE submitted [redacted][55] The 2015 Record Period shows an improvement in both the number of bids

[52] A.16-04-001, Testimony, Chapter II, Part E, Section 1, p. 19-20.

[53] *Id.*, p. 20.

[54] *Id.* Chapter II Workpapers, "Section E_Inc Bid Cost Variance Methodology."

[55] A.15-04-002, Supplemental Testimony, Chapter III, Part A, p. 4.

with variances and in the overall cost impact of these variances. ORA does not recommend a disallowance, but does recommend that SCE continue to monitor and update its bidding system to prevent future errors.

### iii. Bidding Activity

SCE bids all available resources into the market at their incremental cost and if the LMP (the price of energy at the node where the resource is sited) is greater than or equal to the bid price, CAISO will dispatch the resource. Although not reported in testimony, SCE stated that it is "not aware of" any instances in which a resource was not bid into the CAISO market when it was available.[56] **SCE is also not "aware of" occasions when incremental energy was not awarded wh**en the incremental bid cost at the awarded MWh level was below the LMP.[57] However, SCE's incremental bid cost variance workpapers included 59 occasions in which the LMP was greater than both the clean and calculated bid, but the resources did not receive a market award.[58] When ORA further investigated these 59 occasions, SCE explained that on these occasions the resources had been off-line and when factoring in start-up costs, it was not economic for CAISO to dispatch the resource.[59]

The requirements described in D.15-05-007 state that the utility must report the "[p]ercentage of times incremental energy was not awarded when incremental bid cost at the awarded megawatt ("MW") level was lower than the Locational Marginal Price ("LMP") at the applicable node."[60] ORA disagrees with SCE's explanation that this reporting only serves to indicate incorrect dispatch decisions[61] as the Decision does not make this distinction. ORA only received SCE's explanation about the 59

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[56] SCE Response to Data Request 21, Question 2.

[57] *Id.*, Question 3.

[58] A.16-04-001, Chapter II Workpapers, "Section D_Inc Bid Cost Variance Impact."

[59] SCE Response to Data Request 22, Question 4.

[60] D.15-05-007, Appendix A, Item 3.

[61] SCE Response to Data Request 22, Question 4.

aforementioned occasions after substantial analysis and data discovery, but ORA does not have the resources to verify all of SCE's bidding activity to determine whether there are any additional occasions in which SCE's resources did not receive a market award despite the bid cost being below the LMP.

SCE did not provide the necessary bidding activity data in its testimony, despite the clear requirement in D.15-05-007 to do so.[62] Additionally, SCE failed to perform the necessary analyses on its own bidding and dispatch data to provide the full and correct information when ORA requested the data. The purpose of the requirement to provide this data in testimony is for the utilities to prove to the Commission that they managed their resources according to least-cost principles. If the information and analysis is not provided, it demonstrates a lack of due diligence and transparency. Additionally, because SCE did not provide the required data and did not perform the necessary analysis, ORA cannot determine whether there are additional omissions in SCE's analysis and reporting. ORA recommends:

- The Commission order SCE to improve its bidding activity reporting in accordance with the D.15-05-007 and clearly provide data for the number of times resources were not bid into CAISO markets when available (even if it was zero times) and the percentage of times incremental energy was not awarded when the incremental bid cost was below the LMP (even when 0% or if the added start-up and minimum load costs make dispatch uneconomic).

**iv. Self-Commitment**

In the 2015 Record Period, [redacted][63] [redacted]

[62] D.15-05-007, Appendix A, Item 3.

[63] A.16-04-001, Testimony, Chapter II, Part E, Section 1, p. 20.

[redacted][64] ORA recognizes the benefit in [redacted] for efficiency and air quality purposes and finds these self-commitments to be reasonable.

## D. Management of Hydro Resources

### i. Overview

Hydro generation is use-limited, meaning that because the amount of water is limited, hydroelectric generation may not be the most economic option at all times. In addition to the natural seasonal variability of water, 2015 was a drought year for California and therefore a low hydro year. While some hydro resources cannot be controlled at all, such as run-of-river resources, others can store water behind a dam and are bid into the CAISO markets at their incremental costs. Hydro resources do not have explicit fuel costs as thermal resources do, and so while the incremental cost of providing hydro power does not include fuel, utilities must consider the opportunity costs of utilizing the resource at a future time when it may be more valuable.

Least-cost dispatch of hydro resources must take into consideration the uncertainty of weather conditions such as the likelihood of precipitation and high temperatures, the future availability of water, and any potential operating constraints. Hydro resources have the highest value to customers when they are dispatched during high energy value periods and can offset or suppress high costs.

### ii. Analysis

In the 2015 Record Period, SCE only had three dispatchable hydro resources in its portfolio: Big Creek, Eastwood, and Hoover facilities. In addition to providing hydroelectric energy, Eastwood is a pumped storage facility but due to the ongoing

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[64] *Id.*, Part D, Section 1, p. 16.

drought in California, was unable to provide pumped storage services.[65] [redacted][66] To further refine these data, ORA also looked at the 100 highest energy value hours. Of these, [redacted][67]

As mentioned earlier, in order to maximize their value, it is optimal for hydro resources to be dispatched during times when energy is most expensive. [redacted] However, it is not evident from the data provided that it would have been possible for Eastwood to have been dispatched more often, given the low hydro conditions. From its performance, it appears that SCE correctly prioritized the 100 highest energy value hours.

### iii. Summary and Recommendations

SCE did not explicitly provide the information about hydro dispatch during the 100 highest energy value hours in its workpapers despite the clear requirement to do so described in D.15-05-007 outlining the utilities' LCD requirements.[68] Further, the information about Eastwood's inability to provide pumped storage was only reported in

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[65] In order to perform pumping operations, Shaver Lake (the reservoir upon which the facility is located) must have a high enough water level to cover the pump intake tunnel. During 2015, the water level never reached this height and so pumping was not possible. (*Id.* Chapter III Testimony, Section D, Part 3, p. 54-55.)

[66] SCE Response to Data Request 15, Question 1.

[67] *Id.*

[68] D.15-05-007, Appendix A, Item 5.

Chapter III but was necessary for determining this resource's compliance with least-cost principles. Because of ORA's considerable effort in parsing this information from the provided data and running its own analyses, it was not possible to compare hydro performance in 2015 to 2014. Based on the information from 2015 alone, ORA determines that SCE did manage its dispatchable hydro resources according to least-cost principles. However, ORA had to perform many of the analyses that should have been clearly presented in SCE's testimony and workpapers. Additionally, ORA cannot determine the accuracy of SCE's hydro models based on the data provided and therefore cannot determine whether SCE can make any improvements to their forecast systems. ORA recommends:

- The Commission order SCE to improve its hydro reporting in accordance with the D.15-05-007 and clearly provide data for the bidding and dispatch during the 100 highest LMPs of the year at each resource location.
- The Commission order SCE to report in the LCD chapter any and all limitations to dispatch of hydro and pumped storage resources – including unavailability due to drought and/or outages[69] – when relevant to hydro least-cost dispatch.
- The Commission order SCE to undergo an independent review by an outside party of its hydro models to determine whether they are reasonable or if SCE could make any improvements. The plans for this review must be in place by the time SCE files its next ERRA compliance application.

### E. Management of Dispatchable Renewable Resources

As renewable resources become more sophisticated and "controllable," the Commission will need to review the utilities' bidding and scheduling practices for these resources. In addition to calculating the cost components making up the bid costs for the economic dispatch of renewable energy in the day-ahead market, the utilities evaluate

[69] The requirement to report lost capacity due to planned or forced outages is already described in D.15-05-007, Appendix A, Item 6b.

market prices and opportunity costs associated with the curtailment of renewables. For example, sometimes the CAISO-reported net energy demand approaches the minimum must-offer threshold and increases the risk of overgeneration. At these times, energy prices are often negative to provide a financial incentive for generators to "turn off" and reduce the amount of energy flowing into the grid. This scenario typically occurs midday when solar generation is at its peak.

By the time scheduling coordinators consider curtailing renewable resources, other thermal resources with flexible operating protocols have already been turned off, so renewables are the next type of energy resource that can be curtailed to prevent energy overgeneration. However, to ensure compliance with California's Renewable Portfolio Standard (RPS), the utilities assess the opportunity cost of not generating the Renewable Energy Credits associated with renewable generation when determining their curtailment bids. Renewable energy contracts also often have limits to the number of annually allowed curtailments so the utilities must consider these contractual constraints when curtailing.

Renewable curtailment entails submitting negative bid prices to CAISO in order to prevent the resources from being dispatched when market prices are negative. During negative pricing events, the utilities effectively have to pay to generate electricity, which in turn is reflected in electricity rates. Prudent curtailment has the potential to save ratepayers money, but the utilities must consider RPS compliance, contractual constraints, and market dynamics to ensure that their curtailment decisions are prudent.

SCE had two dispatchable renewable resources in its portfolio in the 2015 Record Period: McCoy Solar and Alta Wind.[70] SCE submitted negative bids[71] for both resources into the CAISO day-ahead market in order to protect against extreme negative price

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[70] SCE Response to Data Request 20, Question 3.

[71] The process of submitting negative price bids to CAISO or self-scheduling resources at a negative price is what is referred to as curtailment. When the bid price is a very low negative dollar amount, it ensures that it will be below the LMP (even during negative pricing events) so that CAISO will not dispatch the resource.

events when SCE would have to pay to generate electricity.[72] SCE similarly curtailed other renewable resources at times that it was economical to do so, such as when market prices were significantly negative and energy generation would have incurred "excessive costs."[73] The utilities must report their bidding and dispatch activity for all dispatchable thermal and hydro resources in ERRA compliance testimony in order for the Commission to determine whether they are managing their dispatchable portfolio according to least-cost dispatch standards. As renewable resources become more flexible and are dispatched and curtailed through the CAISO market, the Commission should require SCE to provide information about its renewable resource bidding and curtailment in future testimony. This will allow the Commission to judge how SCE achieves least-cost dispatch with respect to its entire dispatchable energy portfolio and how renewable contractual constraints, economic factors, and opportunity costs affect bid prices, bidding activity, and the subsequent electricity rates passed along to ratepayers. ORA recommends:

- The Commission order SCE to include in its future testimony reporting and quantitative calculations of any renewable resource opportunity costs by type (e.g. wind, solar, etc.).
- The Commission order SCE to include in its future testimony explanations of energy curtailment, such as instances when it is necessary, how the economic decision to curtail a resource is made, the business process for curtailing a resource, and any quantitative metrics associated with this process.

### F. Management of Demand Response Programs

#### i. Pre-CAISO Market Integration

SCE operates several types of DR programs, but ORA's analysis focuses on DR resources with economic triggers. The DR programs that SCE manages that are

[72] SCE Response to Data Request 22, Question 8, Part c.

[73] SCE Response to Data Request 20, Question 4.

dispatched when economic triggers are met are Aggregator Managed Portfolio (AMP), Capacity Bidding Program (CBP), and the Summer Discount Programs (SDP). AMP resources can only be dispatched [redacted] The AMP programs managed by [redacted] have a tariff limit of [redacted] and are triggered when [redacted][74] The AMP programs managed by [redacted] are limited to [redacted] and are triggered when [redacted][75] The CBP can be dispatched on both a day-of and day-ahead basis and is limited to [redacted][76] The CBP trigger condition occurs when [redacted][77]

The Commercial Summer Discount Program (SDP-C) is limited to [redacted] per year,[78] and the Residential Summer Discount Program (SDP-R) is limited to [redacted] per year.[79] SDP resources could only be dispatched on [redacted][80] The SDP tariffs [redacted][81]

The following analyses focus only on SCE's management of its DR resources before CAISO market integration.

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[74] A.16-04-001, Chapter II Workpapers, "DR-AMPDO_ENERNOC_CONFIDENTIAL."

[75] *Id.*, "DR-AMPDO_ECI_CONFIDENTIAL."

[76] *Id.*, "DR-CBPDA14_CONFIDENTIAL," "DR-CBPDA26_CONFIDENTIAL," "DR-CBPDO14_CONFIDENTIAL," "DR-CBPDO26_CONFIDENTIAL."

[77] A.15-04-001, ORA Testimony, Chapter II, p. 2-6.

[78] A.16-04-001, Chapter II Workpapers, "DR-SDPC_CONFIDENTIAL."

[79] *Id.*, "DR-SDPR_CONFIDENTIAL."

[80] SCE Response to Data Request 14, Question 1, Part a.

[81] SCE SDP Tariff, Sheet 2. https://www.sce.com/NR/sc3/tm2/pdf/ce342.pdf.

For the AMP resources managed by [redacted] between January 1 and July 14, 2015 there were [redacted] instances when the price trigger was reached but not forecast, and the resources were not dispatched. [redacted] of these instances occurred [redacted][82]

For the AMP resources managed by [redacted], between January 1 and June 30, 2015 there were [redacted] instances when the price trigger was reached but not forecast, and the resources were not dispatched. There were [redacted] instances when the trigger price was forecast and the resource was dispatched.[83] Because these programs require SCE to notify DR customers [redacted] in advance of a dispatch event,[84] it is possible that SCE did not have time to notify its customers in time to dispatch the resources on these occasions.

For the two types of day-ahead CBP programs, between January 1 and June 14, 2015 there were [redacted] occasions when the trigger condition was met but not forecast and the resources were not dispatched. Of the [redacted] occasions that the trigger condition was met, [redacted] were forecast.[85] For the two types of day-of CBP programs, between January 1 and June 17, 2015 there were [redacted] occasions when the trigger condition was forecast and the resources were not dispatched. Of the [redacted] occasions that the trigger condition was met, [redacted] were forecast.[86]

For SDP-C and SDP-R resources, between January 1 and July 23, 2015 there were [redacted] occasions when trigger conditions were met but not forecast and the resources were

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[82] A.16-04-001, Chapter II Workpapers, “DR-AMPDO_ECI_CONFIDENTIAL.”

[83] *Id.*, “DR-AMPDO_ENERNOC_CONFIDENTIAL.”

[84] SCE Response to Data Request 14, Question 2, Part d.

[85] A.16-04-001, Chapter II Workpapers, “DR-CBPDA14_CONFIDENTIAL,” “DR-CBPDA26_CONFIDENTIAL.”

[86] *Id.* “DR-CBPDO14_CONFIDENTIAL,” “DR-CBPDO26_CONFIDENTIAL.”

not dispatched. For SDP-C, [redacted] occasions that the trigger occasions were met were forecast [redacted] while [redacted] were forecast for the SDP-R program.[87]

Typically, ORA evaluates the utilities' management of their Demand Response based on the performance over the entire Record Period. Because integration into the CAISO began in June and July, after which the DR dispatch data changes significantly, ORA can only analyze SCE's trigger forecast accuracy for approximately six months per program. Additionally, some of the DR programs [redacted]) did not have any dispatchable hours available until May or June. Between [redacted] of the trigger conditions were forecast for all of the DR programs in 2015, which is [redacted] SCE's forecast accuracy in 2014,[88] but those were based on performance for the entire year. ORA therefore cannot determine whether SCE's DR resource management was reasonable and consistent with least-cost principles with only half a year of data.

**ii. Post-CAISO Market Integration**

Following integration of the DR resources into the CAISO market, [redacted][89] [redacted][90] [redacted][91] [redacted][92] [redacted]

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[87] *Id.* "DR-SDPC_CONFIDENTIAL," "DR-SDPR_CONFIDENTIAL."

[88] A.15-04-001, ORA Testimony, Chapter II, p. 2-8.

[89] Except the SDP-R program, which was broken into nine groups. (SCE Response to Data Request 14, Question 2, Part b.)

[90] *Id.*

[91] *Id.*

[92] 70 resources were chosen because "SCE determined that approximately 70 resource IDs was the most that could be reasonably managed, with current tools and processes, in front and back office operations." (*Id.* Part g.)

[redacted][93] These final [redacted] resources are bid into the CAISO market and dispatched when the trigger conditions are met, much like with dispatchable resources for which SCE submits bids and which are dispatched when the market price is higher than the bid price.

[redacted][94]

For the AMP program managed by [redacted], there were [redacted] when the price trigger condition was met and so [redacted] following market integration. For the AMP program managed by [redacted], the price trigger was met (and therefore the resource was dispatched) [redacted] after market integration. For the whole year, [redacted][95]

For the two types of day-ahead CBP programs, the resources were dispatched [redacted] of its allotted number of hours following market integration. For the entire year, this use factor totaled [redacted].[96] For the two types of day-of CBP programs, the resources were dispatched for [redacted] their allotted number of hours following market integration, and the total use factor for the whole year was [redacted]

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[93] *Id.* Part g.

[94] *Id.* Part d.

[95] A.16-04-001, Chapter II Workpapers, "DR-AMPDO_ECI_CONFIDENTIAL," "DR-AMPDO_ENERNOC_CONFIDENTIAL."

[96] *Id.* "DR-CBPDA14_CONFIDENTIAL," "DR-CBPDA26_CONFIDENTIAL"

[redacted].[97] Additionally, [redacted] were dispatched over the whole year.[98]

### iii. Summary and Recommendations

SCE did not provide in its testimony or workpapers any information about DR opportunity cost calculation, CAISO market integration, or instances when a DR trigger was met but the resource was not dispatched, other than the trigger not being forecast. Despite the clear requirement to do so in Decision D.15-05-007,[99] all of these details reported here came from a data request response. Going forward, SCE should provide more information in its testimony and workpapers, adapted to explain its opportunity cost calculations and bids as they are submitted to the CAISO market.

As mentioned earlier, ORA cannot assess SCE's overall DR forecast accuracy since it was only necessary to forecast trigger conditions for half of the Record Year. In terms of use factor, or the percent dispatched of total number of hours as allotted in the tariff, SCE's performance is compared with the previous Record Period:[100]

| DR Program Type | 2015 Use Factor | 2014 Use Factor |
|---|---|---|
| AMP – [redacted] | [redacted] | [redacted] |
| AMP – [redacted] | [redacted] | [redacted] |
| Day-Ahead CBP (1-4) | [redacted] | [redacted] |
| Day-Ahead CBP (2-6) | [redacted] | [redacted] |
| Day-Of CBP (1-4) | [redacted] | [redacted] |
| Day-Of CBP (2-6) | [redacted] | [redacted] |
| SDP-C | [redacted] | [redacted] |

[97] *Id.* "DR-CBPDO14_CONFIDENTIAL," "DR-CBPDO26_CONFIDENTIAL."

[98] *Id.* "DR-SDPC_CONFIDENTIAL," "DR-SDPR_CONFIDENTIAL."

[99] D.15-05-007, Appendix 2, Items 1 and 8.

[100] A.15-04-001, ORA Testimony, Chapter II, p. 2-9,10.

[101] [redacted]

| SDP-R | [redacted] | [redacted] |
|---|---|---|

Overall, SCE's DR program management improved for most of its resources. There are aspects to the CAISO market integration that yielded a better outcome for some types of DR programs than others. Because this was a partial year, ORA cannot determine whether, as a whole, SCE managed its DR resources according to least-cost principles. However, SCE could significantly improve its reporting. ORA recommends:

- The Commission order SCE to report all of the Demand Response metrics and data relevant to post-CAISO market integration DR dispatch in its testimony and workpapers according to D.15-05-007.
- The Commission order SCE to report any metrics, calculations, evaluations of opportunity costs, bidding activity, and processes associated with the CAISO market integration process that are not delineated in D.15-05-007 but that explain this process in a way that allows the Commission to evaluate compliance with least-cost dispatch principles.

## V. CONCLUSION

ORA finds that SCE managed most of its resources responsibly except its commitment cost calculations, for which ORA recommends [redacted] Because the reason for the commitment costs errors for 2012 through 2014 was only reported in the Record Period 2015 filing, ORA had new reason to analyze the cost impacts incurred as a result of these errors. Upon doing so, ORA found that the errors are unreasonable and the fact that SCE did not notice or report them until 2016 demonstrates a lack of due diligence. ORA also recommends that SCE provide substantially more information in its testimony and workpapers with respect to price and load forecast; thermal bid cost calculation; hydro bidding, dispatch, and pumped storage data; management of renewable resources; and DR following CAISO market integration. Additionally, ORA recommends that SCE undergo independent reviews by a third party of its price and load forecast models and its hydro forecast models, and for the plans of these reviews to be in place by the time SCE files its next ERRA compliance application.

ORA is open to working with SCE to determine the best format and content for this information.

# CHAPTER 3: UTILITY-OWNED GENERATION – HYDROELECTRIC

(Witness: Michael Yeo)

## I. INTRODUCTION AND RECOMMENDATIONS

This chapter addresses the operation and management of Southern California Edison's (SCE) utility-owned hydroelectric (hydro) facilities, and the outages that occurred at those facilities during the 2015 Record Period.

After reviewing SCE's testimony and responses to Office of Ratepayer Advocates' (ORA's) data requests, ORA recommends the Commission order SCE:

(a) implement the corrective actions identified in the Root Cause Evaluation Report for the Kern River 3, Unit 1 outage, and

(b) report those corrective action implementations in the annual Energy Resource Recovery Account (ERRA) Compliance filing for the 2016 Record Period, and the effectiveness of those implementations.

## II. GENERATION FACILITIES[102]

The Hydro Division is organized into two regions, northern (Northern Hydro) and eastern (Eastern Hydro). Altogether, SCE owns, operates, and maintains 33 hydroelectric generating plants, with an aggregate 1,176 MW of nameplate generating capacity. Figure 3.1 shows its hydro system in California.

SCE's hydro operation for Record Period 2015 was significantly impacted by the drought. According to SCE, 2015 was California's driest year, surpassing the previous record set in 2014 based on records dating to the 1800s.

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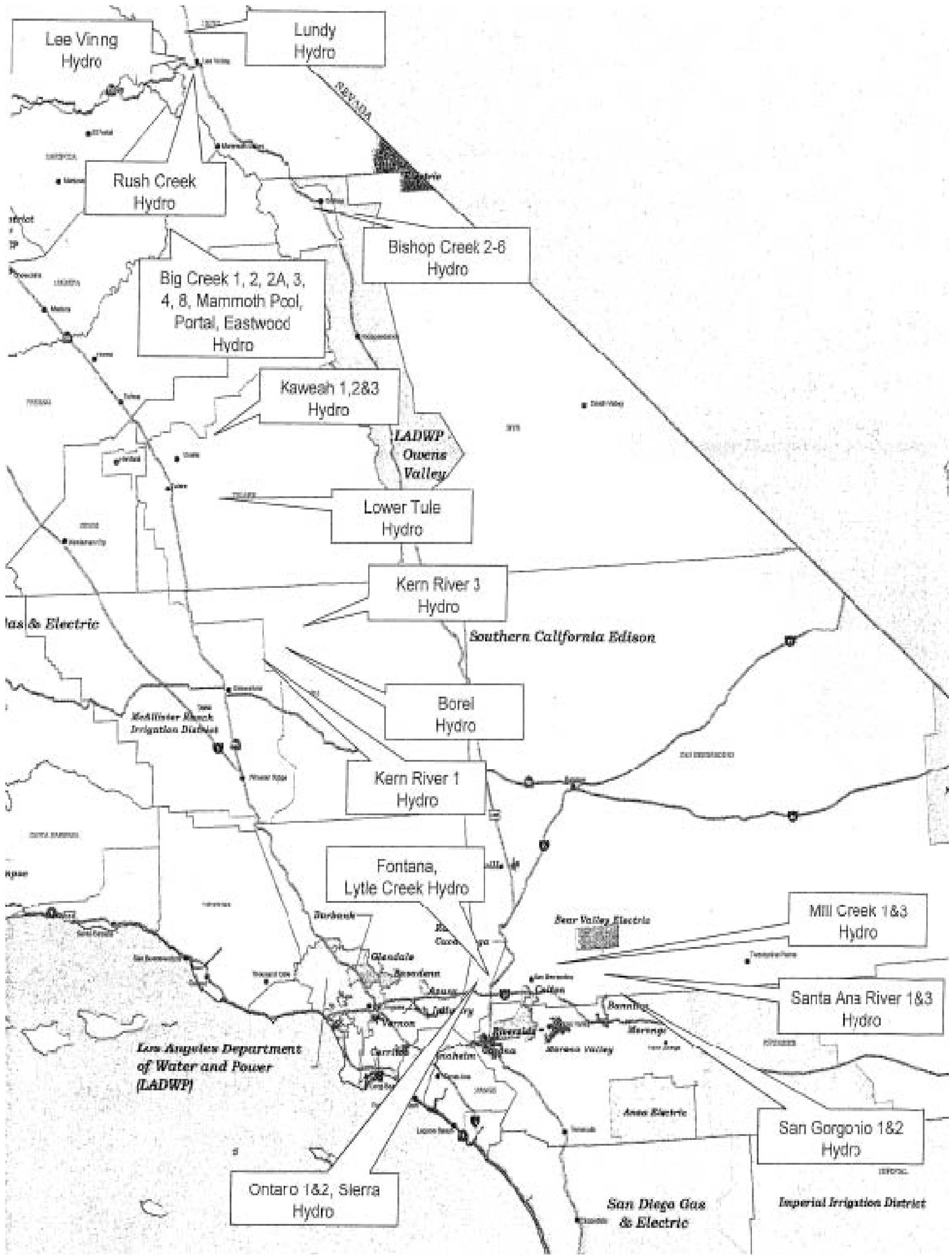
[102] Information about SCE's generation facilities was provided in SCE's testimony at p. 33 and in responses to ORA data requests #1 and #11.

**Figure 3.1[103]**
**SCE's Hydro System**

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[103] SCE's response to ORA data request #11.1.

## III. OUTAGE

For the 2015 Record Period, ORA reviewed the Kern River 3, Unit 1 outage that began on December 18, 2014 at 10:04 a.m. and ended on March 13, 2015 at 2:30 p.m., a total of 85.185 days.[104] ORA was interested in this incident because of the length of the outage.

### A. Kern River 3, unit 1 Outage – December 18, 2014

The Kern River 3 generating facility consists of two units, Unit 1 (20.5 MW) and Unit 2 (19.68 MW). It is located approximately 50 miles east of Bakersfield and approximately 7 miles North of Kernville alongside Sierra Way, California State Highway 521. It is not interconnected to the Kern River 1 generating facility.[105]

SCE, in its testimony, states that the cause of this outage was due to the failure of the limit switch. This switch is a part of the valve actuator, which is also referred to as the penstock gate actuator.[106] (See Figure 3.2) Because of this failure, the valve actuator over-traveled when being closed, causing damage to the upper valve stem and the concrete deck seating of the actuator and motor.

SCE, in its testimony,[107] stated that this incident occurred on December 18, 2014 when the penstock (Figure 3.3) was being filled in preparation for returning Unit 1 and 2 back to service availability after a planned outage. When the control operator was remotely adjusting the penstock's water inlet gate valve between the open and closed positions, the limit valve failed, damaging the valve stem and the concrete deck seating.

SCE added that repairs to the damaged Unit 1 gate actuator foundation and upper valve stem, and replacement of the actuator were performed during the second week of

[104] SCE's response to ORA data request #11.9

[105] SCE's response to ORA data request #11.8. In ORA data request #11.6, SCE responded that there is no facility known as Kern River 2.

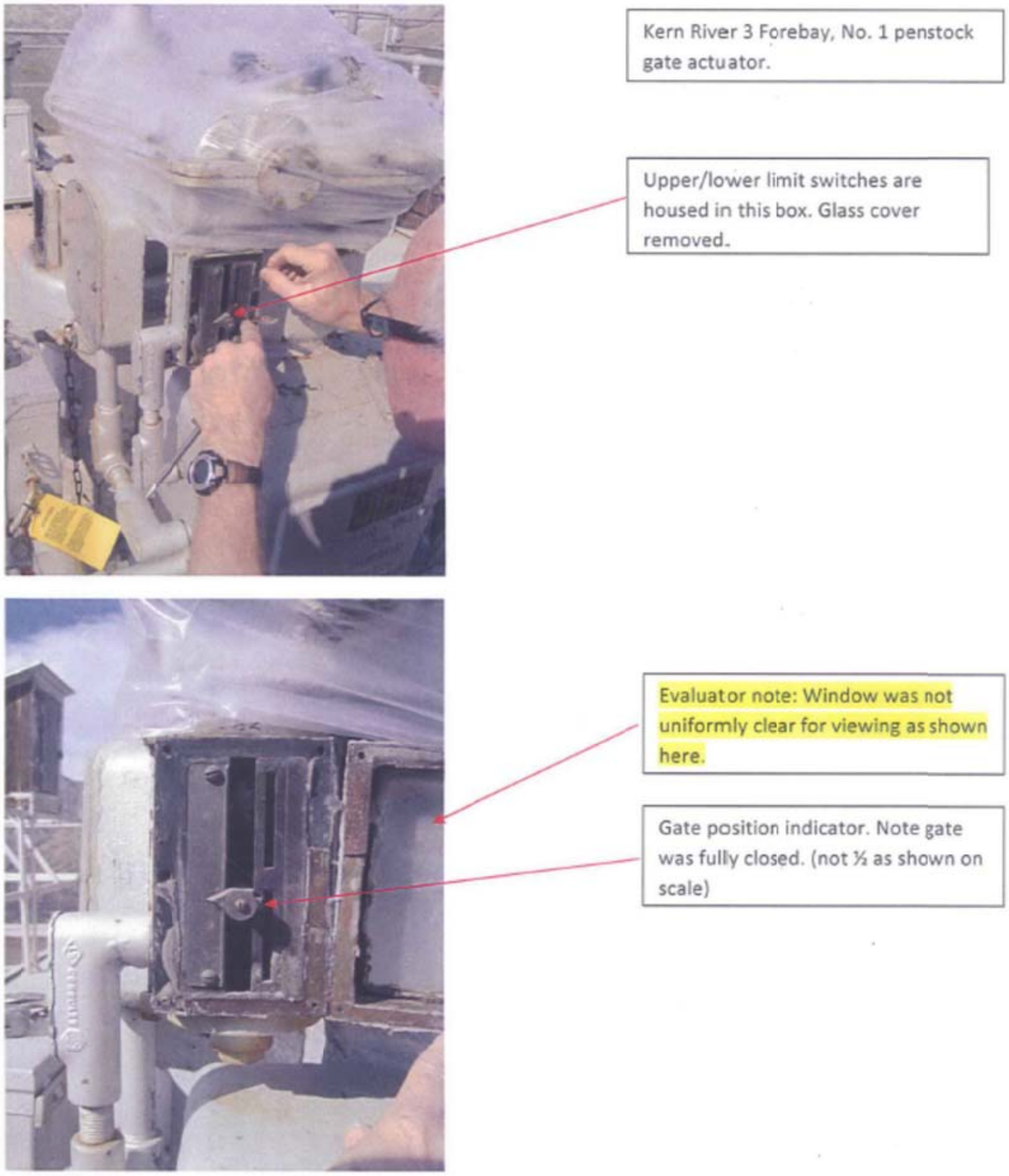
[106] SCE's response to ORA data request #13.

[107] SCE's testimony SCE-01C, page 51.

March 2015 and Unit 1 was returned to a ready-for-service condition on March 13, 2015.[108]

[108] Ibid.

**Figure 3.2[109]**
**Kern River 3, Unit 1 – Penstock Gate Actuator* and Limit Switch****




* "Penstock Gate Actuator" is the mechanism used to open and close the penstock gates.
** A "limit switch" is an electrical switch that opens (or closes) when a moving device reaches a certain pre-determined position (e.g., such as the fully-opened, or fully-closed, position). In this case, the limit switch monitors the penstock gate position, and acts to shut off the electrical

[109] SCE's response to ORA data requests #11.11, #11.13 and #11.16.

current (i.e., shuts off power) to the motor which powers the drive gear (i.e., spins the drive "nut") on the actuator assembly when it is in the fully-closed (or fully-opened) position.

**Figure 3.3[110]**
**Kern River 3 Penstock**

A penstock is a pipe (or sometimes multiple pipes) used to convey water from a hydroelectric power plant's forebay to the turbines.

[110] SCE's response to ORA data request #11.12.

ORA reviewed SCE's application, prepared testimony, and responses to ORA's data requests for the 2015 Record Period. Also, SCE met with ORA on May 25, 2016 at SCE premises in Redland, CA, to provide an overview of its hydro operation. There was also a July 11, 2016 telephone conversation to clarify some information that SCE provided.

In addition, ORA reviewed the document titled *2015 Kern River 3 Unit 1 Forebay Actuator RCE* (RCE Report).[111] The RCE Report is SCE's post-mortem report which was included in its Workpapers for SCE-1 Chapters I, II, IV and V (Workpapers); these Workpapers were submitted by SCE to support its testimony.

SCE, explained why it took SCE 85 days to restore the facility back to service as follows:

> *"The length of the outage is relative to the scope of the damage and necessary repairs. While procurement of the penstock gate actuator was expedited to the extent possible, manufacturer lead time required to procure a suitable replacement (as noted in testimony the existing actuator was installed in the 1950s) was a major contributing factor. In addition, time necessary to assess the extent of the damage and to re-engineer and rebuild the structural foundation were also contributing factors."*[112]

Corrective Actions

Following this outage event and the repairs done to restore Unit 1 back to service, SCE also enacted several corrective actions. These corrective actions arose as a result of SCE's post-mortem analyses. SCE, in its testimony,[113] raised two operational deficiencies:

i. There was not a specific routine testing and inspection program in place for the gate actuators and limit switches. During the repairs for this event, SCE personnel noted evidence that

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[111] This is a 24-page report dated May 11, 2015.

[112] SCE's response to ORA Data Request #11.10.

[113] SCE's testimony SCE-01C, page 51-52.

previous repairs had been performed at some unknown earlier time. However, records of past repairs to the actuator and limit switches could not be found. Therefore, lack of records documenting any earlier problems and on work pertaining to the maintenance and repairs to the actuator and limit switches (when it appeared that at least one earlier repair had been performed) was identified as a potential contributing cause to the event.

ii. An additional contributing cause for the event was the failure to follow the operating procedure. The operating procedure specifies that a local operator should be present (*i.e.*, at the location of the valve) to observe the inlet valve operation as it is being remotely operated by the control operator for penstock filling. Had a local operator been present, it was possible that personnel at the valve location would have more quickly determined the full extent of problems than the operator in the control room.

The corrective actions as stated in the testimony are:

(a) Perform a survey of other SCE Hydro Powerhouses to determine if other similar vintage actuators exist within SCE's Hydro fleet,

(b) Incorporate routine inspection and testing of gate limits into the existing preventative maintenance program,

(c) Replace both gate actuators at Kern River 3, and

(d) Adopt a 3-way communication protocols and direct observation of actuators during penstock fill conditions.

The corrective actions as identified in the RCE Report are included in Attachment 3.1. The RCE Report states that some of the corrective actions have already been implemented.

<u>Cost of Outage</u>

The cost of the outage consists of two components: the cost of energy that SCE had to purchase to replace the unavailable generation facility, and the cost of the repair work at the Kern River facility.

SCE states that there is no lost generation[114] for this incident because of the drought condition, the low Kern River water flow levels at the time, and the availability of the other generating unit (Unit 2) at the powerhouse during almost the entirety of the outage (with the exception of Jan 6 through 10, when Unit 2 was inoperable).[115] [116] According to SCE, Kern River 3 Unit 1 did not resume generating electricity until April 28, 2015, when enough water had become available for it to do so.[117]

SCE's direct cost of the outage to repair the damage was $557,622.67. The cost breakdown is as follows:

**Table 4-1**
Direct SCE Cost[118]

| Line No. | Description | Amount |
|---|---|---|
| 1 | Labor | $53,862.76 |
| 2 | Contract | $422,767.22 |
| 3 | Materials | $72,381.80 |
| 4 | Other | $8,610.89 |
| 5 | Total | $557,622.67 |

SCE also adds that the costs of labor and materials are funded through SCE's approved General Rate Case base rates (see Attachment 3.2).

Therefore, the total cost of this outage from both replacement power and SCE's direct cost is estimated to be $557,622.67.

## IV. CONCLUSIONS AND RECOMMENDATIONS

Based on ORA's review of the afore-mentioned documents and report, ORA agrees with the implementation of the corrective actions listed in the RCE Report. ORA

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[114] In SCE's response to ORA data request #11.25, SCE equates "lost generation" as "outage bypassed energy": based on this definition, if there is no bypassed energy, there is no "lost generation."

[115] Workpapers, page 2586.

[116] SCE's response to ORA data request #11.25.

[117] SCE's response to ORA data request #11.10.

[118] SCE's response to ORA data request #11.40.

also agrees that there was no lost generation for Unit 1 because of the drought condition. However, to prevent a potential recurrence ORA recommends that the Commission order SCE to:

(a) implement the corrective actions identified in the Root Cause Evaluation Report for the Kern River 3, Unit 1 outage, and

(b) report those corrective action implementations in the annual ERRA Compliance filing for the 2016 Record Period, and report the effectiveness of those implementations in preventing recurrence in the next ERRA compliance filing.

# CHAPTER 4: UTILITY-OWNED GENERATION – NATURAL GAS

(Witness: Michael Yeo)

## I. INTRODUCTION AND RECOMMENDATIONS

This chapter addresses the operation and management of Southern California Edison's (SCE) utility-owned natural gas facilities, and the outages that occurred at those facilities during the 2015 Record Period.

After reviewing SCE's testimony and responses to ORA's data requests, ORA recommends that the Commission:

(a) disallow cost recovery of $107,810 in SCE's Energy Resource Recovery Account (ERRA) Balancing Account for the 2015 Record Period because SCE was accountable for the April 26, 2015 Mountainview Generating Station Unit 3 outage; and

(b) order SCE to submit a copy of the contractor's (Accurate Machine &Tooling) revised testing procedure in the next ERRA Compliance filing for the 2016 Record Period.

## II. GENERATION FACILITIES[119]

SCE owns, operates, and maintains five natural gas-fired peaking generating plants (SCE Peakers) and a combined-cycle gas-fired generating station known as Mountainview.

### A. SCE Peaker Facilities

As a result of heat and power-demand conditions experienced in southern California during July and August 2006, an "Assigned Commissioners' Ruling Addressing Electric Reliability Needs in Southern California for Summer 2007" (ACR) in Rulemakings (R.) 05-12-013 and R.06-02-013, directed SCE to develop five SCE-owned, black start capable peaker units,[120] of up to 250 megawatts (MW) total generating capacity, in order to provide urgently needed capacity and grid reliability for its entire

[119] Information about SCE's generation facilities was provided in SCE's testimony and data request responses.

[120] Black start is the ability to start or restore a power generator to operation without relying on energy sources external to the facility.

transmission and distribution system.[121] The objective was to reduce the risk of shortages and blackouts during peak demand periods and other system emergencies.

SCE filed Application (A.) 07-12-029 in order to recover costs associated with acquiring and installing the five Peakers, the first four of which became operational in September 2007.

The June 9, 2009 Scoping Memorandum in A.07-12-029 excluded costs related to the fifth peaker which had not yet been constructed, and ordered SCE to file a separate, subsequent application to recover reasonable costs associated with it once it was installed. Decision (D.) 10-05-008 approved SCE's request for the four peakers.

The fifth peaker, the McGrath Peaker Generating Station (McGrath Peaker), became operational on November 1, 2012. SCE then filed A.12-12-028 on December 31, 2012 to demonstrate the reasonableness of the costs incurred to install the McGrath Peaker, and request recovery of the revenue requirement associated with it. The Commission, in D.14-06-043, approved SCE's request.

In its testimony, SCE states that each of the five SCE Peakers consists of a single, simple-cycle combustion turbine generator of approximately 49 MW rated net capacity. Together, the five SCE Peakers offer 245 MW of generating capacity.

Peaker plants, because they are small, generally can reach full generating capacity within 10 to 15 minutes to meet immediate demand on the grid. According to SCE testimony, the SCE Peakers contribute to bulk power grid reliability with quick starting and rapid ramping capabilities.[122] Because of their relatively low startup costs and ability to start up and shut down quickly, the SCE Peakers can run several times per day, and only when needed.

SCE adds that the power from its Peakers is used for the CAISO Energy and Ancillary Services markets, where the units can be run to meet unexpected customer demand, respond to unplanned system contingencies, or simply provide required system

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[121] Consolidated ACR dated 8/15/2006.

[122] SCE's testimony SCE-01C.

operating reserves by remaining off-line but immediately available. Because of the Peakers' black-start capability, they can be used to help restore power if the grid experiences a total shutdown or "black-out."

However, there is a limitation to a peaker's use on a daily and annual basis; they are not allowed to exceed their respective daily and annual air emissions permit limits.

The five SCE Peakers are:

**i. Barre Peaker**

The Barre Peaker is located at SCE's Barre Substation in Stanton, California (CA). The commercial operation date was September 20, 2007.

**ii. Center Peaker**

The Center Peaker is located at SCE's Center Substation in Norwalk, CA. The commercial operation date was September 20, 2007.

**iii. Grapeland Peaker**

The Grapeland Peaker is located at SCE's Etiwanda Substation in Rancho Cucamonga, CA. The commercial operation date was September 20, 2007.

**iv. McGrath Peaker**

The McGrath Peaker is located next to NRG's Mandalay Generating Station in Oxnard, CA. The commercial operation date was November 1, 2012.

**v. Mira Loma Peaker**

The Mira Loma Peaker is located at SCE's Mira Loma Substation in Ontario, CA. The commercial operation date was September 20, 2007.

**B. Mountainview Generating Station**

The Mountainview Generating Station (Mountainview Station) is a two-unit (Unit 3 and Unit 4) combined-cycle gas turbine (CCGT) power plant located at the corner of Mountain View Avenue and East San Bernardino Avenue in Redlands, CA. According to SCE testimony, Unit 3 and Unit 4 have a combined total nominal capacity of 1,050

MW. Each unit consists of two combustion turbines and one steam turbine, and generates approximately 525 MW of power.[123]

The current Mountainview Station was built on the site of SCE's former San Bernardino Generating Station, which consisted of two units, Unit 1 and 2, both of which were demolished and removed from the site since decommissioning started in 2009. SCE sold the San Bernardino Generating Station as part of its generation divestiture during electric restructuring.[124] The sale to Thermo Ecotek Corporation was approved by the Commission in D.97-12-106.[125] Thermo Ecotek subsequently changed the name of the facility to Mountainview.[126]

The original project proponent of Unit 3 and 4 was Thermo Ecotek, and its Application For Certification (AFC) was filed with the CEC on February 1, 2000.[127] The CEC approved the AFC on March 21, 2001. AES Corporation on July 31, 2001 purchased Thermo Ecotek from Ecotek's parent company, Thermo Electron Corporation, and the sale included the Mountainview power plant.[128] In April 2003, Intergen (a Shell-Bechtel venture) bought the Mountainview Project from AES.

Sequoia Generating Company, LLC (Sequoia), a subsidiary of Intergen, managed the Mountainview Station project, as Sequoia's subsidiary, Mountainview Power Company, LCC (MVL). SCE, in application, A.03-07-032,[129] filed on July 21, 2003, sought the Commission's authorization to acquire MVL either as a wholly owned

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[123] SCE's testimony SCE-01C.

[124] The divestiture was undertaken in accordance with Decision 95-12-063, as modified by Decision 96-01-009, Assembly Bill 1890, and Decision 03-02-028.

[125] A.96-11-046 *In the Matter of the Application of Southern California Edison Company (U-338-E) for authority to sell gas-fired electrical generation facilities.*

[126] Powermag.com 8/15/2006 article on Mountainview. http://www.powermag.com/mountainview-power-plant-redlands-california/?pagenum=2.

[127] http://www.energy.ca.gov/sitingcases/mountainview/

[128] Thermo Electron Corporation's New Release on July 31, 2001.

[129] In the Matter of the Application of Southern California Edison Company (U 338-E) for Approval of a Power Purchase Agreement under PUHCA Section 32(k) Between the Utility and a Wholly-Owned Subsidiary and for Authority to Recover the Costs of Such Power Purchase Agreement in Rates.

subsidiary and to enter into a Power Purchase Agreement (PPA) with MVL for electricity from the Mountainview Power Project, or as a utility-owned generation facility. The Commission approved the application in D.03-12-059 on December 18, 2003. This application was supplemented with two additional Decisions, D.04-03-037[130] and D.04-04-019.[131] MVL became a wholly-owned subsidiary of SCE, and held a PPA with SCE.

In D.09-03-025,[132] the Commission approved SCE's request to operate Mountainview as a utility-owned generation facility rather than as a PPA lessee. In the GRC Decision, the Commission "…approve[d] the transfer of ownership",[133] and "…allow[ed] SCE to acquire direct ownership of Mountainview, and to include its capital costs in rate base and recover its operating costs through the TY 2009 revenue requirement."[134]

Unit 3 of the Mountainview Station began commercial operation on December 10, 2005, and Unit 4 on January 19, 2006. Each unit produces approximately 525 MW: it consists of two combustion turbines (CTs) rated at 170 MW each, and one steam turbine (ST) rated at 185 MW.[135]

Although Unit 3 and Unit 4 each have a nominal net capacity rating of 525 MW, actual power output varies above and below this figure as a function of ambient weather (i.e., temperature and humidity). Additionally, the Mountainview Station is not operated as a "base-load" plant (i.e., it is not constantly operated at its full rated output level), but rather it is operated as an "intermediate duty" plant (i.e., the power output fluctuates in

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[130] Opinion Adopting Federal Energy Regulatory Commission's Changes To The Mountainview Power Purchase Agreement Approved By This Commission In Decision 03-12-059.

[131] Order Modifying Decision 03-12-059 And Denying Rehearing Of Decision, As Modified.

[132] SCE's GRC Application A.07-11-011 for Test Year (TY) 2009.

[133] D.09-03-025 (A.07-11-011), p. 33.

[134] Ibid, p. 365.

[135] SCE's response to ORA data request #12.3.

real-time based on dispatch orders as required to meet current power requirements and changing market conditions).[136]

## III. OUTAGES

For the 2015 Record Period, ORA reviewed the Mountainview Generating Station outage that started on April 26, 3015.

### A. Mountainview Generating Station Unit 3 Outage – April 26, 2015

SCE, in its testimony,[137] states that the Mountainview Station had only one unscheduled outage which lasted more than 24 hours; ORA chose the Unit 3 forced outage for further review and analysis.

The Unit 3 outage started on April 26, 2015 at 2 p.m. and ended on April 28, 2015 at 12 p.m., a total of 1.92 days.[138]

The shutdown was due to a steam leak developed on a valve bonnet. Unit 3 was being returned to service after a week-long spring outage for maintenance work when the leak developed; this leak led to SCE's decision to shut down Unit 3.

The work done during the maintenance shutdown included: Inspection of the Heat Recovery Steam Generators (HRSG), Inspection of the Cooling Towers, Semi-Annual $CO_2$ System Inspection, Transformer Deluge Fire System Testing, Annual Regulatory Maintenance,[139] Inspection of the Main Steam Stop Valves, Replacement of the backup batteries on Generator and Protection Relays, and the cleaning of the LCI unit and control cabinets.[140]

SCE's testimony adds that, during the maintenance shutdown, the contractor, Accurate Machine &Tooling (AM&T), [141] inadvertently dislocated the gasket retainer

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[136] SCE's Response to ORA data request #12.3.

[137] SCE's Testimony SCE-1, Chapter IV, Natural Gas Generation, page 69, line 22 to page 70, line 2.

[138] SCE's response to ORA data request #12.9.

[139] South Coast Air Quality Management District.

[140] SCE's response to ORA data request #12.10.

[141] SCE's response to ORA data request #12.14 and data request #12.15.

during reassembly of the main steam block valve, HV-501 (see Figure 4.1 and 4.2). AM&T corrected the problem on April 28, and Unit 3 was returned to in-service.

AM&T was selected to service (i.e., replace or repair worn or damaged parts) approximately 20 valves during the scheduled outage from a group of qualified contractors through the Invitation to Bid (ITB) process performed by SCE's procurement department.[142] The repair work, performed on the main steam block valve by AM&T to stop the steam leak, included disassembly of the valve, installation of a new ring to replace the damaged graphite gasket and reassembly of the valve.

SCE explained the amount of time taken to do the work repair as follows:[143]

> *Th*[*e*] *valve operates at approximately 1,050 degrees Fahrenheit. In order to assure worker safety, prior to commencing an investigation, the valve and piping connected to it had to cool down to room temperature, which took approximately 12 hours. The valve* [*cannot*] *be aggressively force cooled (e.g., by spraying the valve with water), as such efforts can damage the valve, the piping and surrounding equipment. Ensuing work included lock-out/tag-out of equipment (to assure worker safety), disassembly of the valve, replacement of the gasket, reassembly of the valve, removal of equipment lock-out/tag-outs, clearance of equipment to ready for service and notification to CAISO.*

[142] SCE's response to ORA data request #12.15.

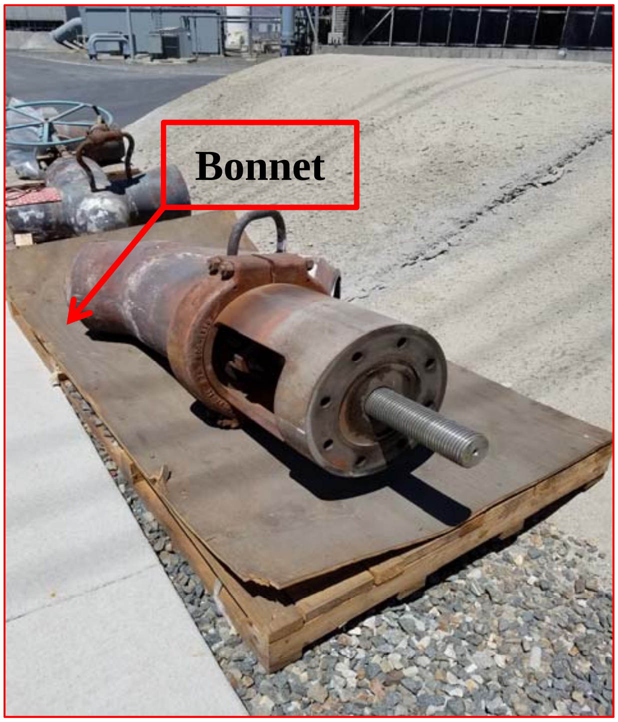
[143] SCE's response to ORA data request #12.16.

**Figure 4.1[144]**
**Main Steam Block Valve – Location of In-Service HV-501 Valve**

[144] SCE's response to ORA data request #12.1.

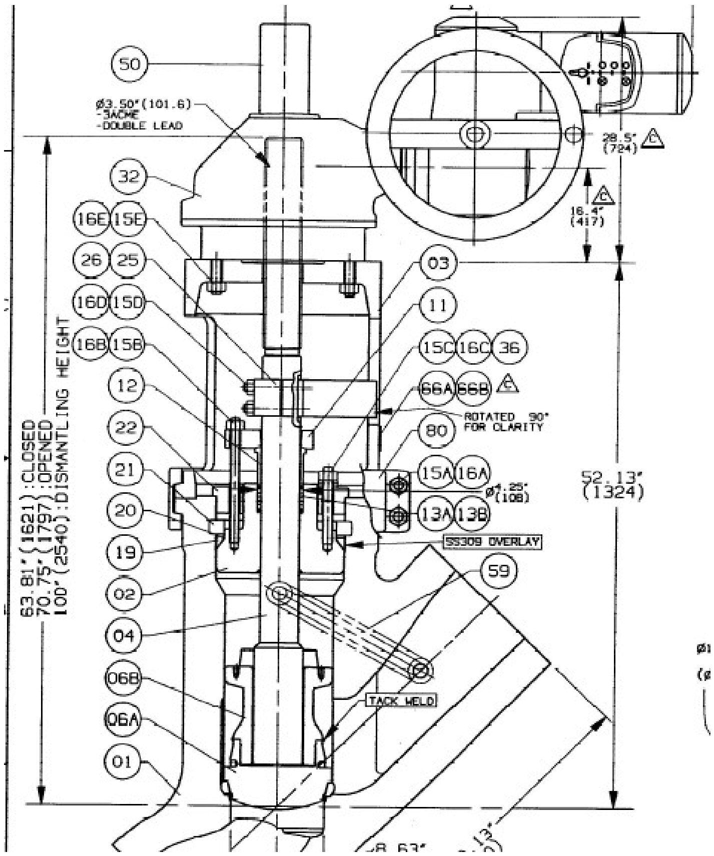
**Figure 4.2[145]**
**Main Steam Block Valve – Photo of Salvaged HV-501 Valve**

The above salvaged valve needs to be disassembled to show the gasket and gasket retainer/keeper parts.




[145] SCE's response to ORA data request #12.1.

**Figure 4.3[146]**
**Main Steam Block Valve (HV-501) – Cross-Sectional View**




The main steam block valve provides isolation of steam to the Steam Turbine. This is two-fold. First, it functions as a Stop Check Valve, i.e., it prevents reverse steam flow between the two Heat Recovery Steam Generators (HRSGs) while they are providing steam to the Steam Turbine. Second, it ensures isolation and prevention of water in liquid state from being introduced into the steam turbine until temperatures have become high enough and water has been completely transformed into a gaseous (i.e., steam) state.

- A breach, or valve, bonnet is the top portion of the valve body (item 02 above).
- A gasket is a composite material which provides a seal between two metal surfaces in order to prevent leakage of material from that connection. (item 19 above)
- A gasket retainer, or keeper, is the guide which holds the gasket in place when the valve is not fully assembled (item 21 above)

[146] SCE's response to ORA data request #12.12.

ORA reviewed SCE's application, prepared testimony, and responses to ORA's data requests for the 2015 Record Period. Also, ORA met with SCE on May 25, 2016 at the Mountainview Station in Redlands to observe the facility and the Main Steam Valve to have a better understanding of the April 26, 2015 outage.

In addition, ORA also reviewed SCE's Root Cause Evaluation (RCE) Report, which was included in its Workpapers for Chapter I, II, IV and V (Workpapers). The RCE Report is titled *2015 Mountainview U3 Steam Leak RCE*.[147] SCE submitted the Workpapers to support its testimony.

The series of events that occurred, as described in the RCE Report, include:

1. Mountainview attempted to startup Unit 3 on April 26, 2015.
2. As pressure buil[t], it was noticed that steam was leaking through the valve bonnet. This was documented in the Operators log on April 26th.
3. The unit was immediately shutdown and the Contractor who previously repaired the valve was called in. They tightened the packing but quickly discovered other issues involved. After disassembling the valve, they noticed that the gasket retainer was knocked off when the valve technician pulled up the bonnet. This caused the seal to blow off when steam pressure started to build.
4. A new ring was installed to replace the blown graphite gasket and the valve was reassembled and returned to service.
5. Unit 3 was successfully started up on April 28, 2015."

The RCE Report not only cited human error on the part of the contractor for the steam leak, but stated that the contractor took full responsibility for the incident.

Corrective Actions

The RCE Report indicated that repairs were done to restore the unit back to service. However, SCE states that because AM&T performed the repair work at no charge to SCE, AM&T did not provide the details of the repairs performed or parts

[147] This is an undated nine-page report.

replaced.[148] To avoid recurrence of the mistake, AM&T's valve testing procedure was also revised to include operating the valve in the open and close direction to validate that the valve would be traveling over its designed full range of travel.[149] As of July 14, 2016, SCE states that it has not received a copy of AM&T's revised testing procedure.[150]

Cost of Outage

The cost of the outage consists of two components: the cost of energy purchased to replace the unavailable generation facility, and the cost of the repair work at the Mountainview Station.

According to SCE, the replacement power cost for the 1.92-day outage was $107,810.[151]

As for SCE's direct cost of the outage, SCE stated, "Accurate Machine & Tooling (AM&T) performed the repair work at no additional charge to SCE. AM&T did not provide SCE with a cost breakdown of the repairs performed or parts replaced."[152]

When ORA asked whether SCE sought reimbursement from AM&T for the replacement power cost, SCE responded, "SCE is not aware of any instance in which Accurate Machine & Tooling (the contractor who performed the work) or other power plant component suppliers, or providers of power plant maintenance services, offer reimbursement of "replacement power costs" as part of their product offerings to their customers."[153]

SCE is ultimately responsible for the outage because it selected AM&T to perform the work from among other bidders through the ITB process,[154] and it should have hired the best-qualified and most competent contractor to do the job. SCE did not provide any

[148] SCE's response to ORA data request #12.23.

[149] SCE's response to ORA data request #12.19 and #12.33.

[150] SCE's response to ORA data request #12.2 supplemental.

[151] SCE's response to ORA data request #12.21

[152] SCE's response to ORA data request #12.23.

[153] SCE's response to ORA data request #12.22.

[154] SCE's response to ORA data request #12.15.

evidence that it did a thorough vetting process of selecting the best contractor to perform the work, nor evidence that the contractor had a track record of performing excellent work.

Ratepayers should not bear the cost of this mistake made by the contractor, and therefore SCE is liable to the ratepayers for this monetary loss.

The total cost to SCE of this outage from both replacement power and SCE's direct cost is $107,810.

## IV. CONCLUSIONS AND RECOMMENDATIONS

Based on ORA's review of the afore-mentioned documents and report, ORA determines that SCE was accountable for the mistake in the work performed by its contractor AM&T. The mistake made by AM&T during maintenance shutdown led to the Mountainview Station Unit 3 outage which occurred from April 26 to April 28, 2015. Because SCE was the party ultimately responsible for the acceptance or rejection of work done by its contractor, SCE bears the accountability of any resulting mishap of work performed by the contractor.

ORA recommends that the Commission:

(a) disallow cost recovery of $107,810 in SCE's ERRA Balancing Account for the 2015 Record Period because SCE was accountable for the April 26, 2015 Mountain Generating Station Unit 3 outage; and

(b) order SCE to submit a copy of AM&T's revised testing procedure in the next ERRA Compliance filing for the 2016 Record Period.

# CHAPTER 5: CONTRACT ADMINISTRATION AND COSTS

(Witness: Mea Halperin)

## I. INTRODUCTION AND SUMMARY

This chapter of testimony presents the Office of Ratepayer Advocates' (ORA's) review of Southern California Edison's (SCE's) contract administration processes and activities for the 2015 Record Period from January 1, 2015 through December 31, 2015. ORA's review focuses on the contract amendments and settlements that resulted in a change to the notional value of the Power Purchase Agreements (PPAs). These amendments were not approved during the Record Period, or in separate applications or advice letters,[155] so SCE is seeking Commission approval in this Energy Resource Recovery Account (ERRA) Application. ORA also reviewed occasions of force majeure (known here as uncontrollable force) and contract terminations to determine whether SCE administered these contracts reasonably.

## II. RECOMMENDATIONS

ORA does not object to SCE's request for approval of the contract amendments resulting in a change in the notional value of the underlying PPA. ORA also does not object to SCE's overall contract administration activities in the Record Period. However, ORA does recommend that the Commission order SCE to clearly indicate in future testimony which items were not previously approved in the Record Period or through any separate decision or resolution, and which items require Commission approval.

## III. BACKGROUND

The Commission has established minimum standards of conduct, including Standard of Conduct 4 (SOC4) for contract administration, stating that the utilities "shall prudently administer all contracts and generation resources and dispatch energy[156] in a

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[155] SCE Response to Data Request 08, Question 5.

[156] This responsibility was further clarified in D.14-05-023, Finding of Fact 15, stating that while the regulated utilities are responsible for bidding and scheduling their generation resources in a least-cost manner, it is the California Independent System Operator (CAISO) who performs actual generation dispatch. (D.14-05-023, p. 19.)

least-cost manner."[157] This ensures that the utilities have "operated [their] resources to produce the lowest possible cost for customers."[158] Prudent contract administration also entails "administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so."[159] In addition, it is the utility's responsibility to "dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs."[160] Finally, the Commission has established that the utility bears the burden of proving that it has administered its contracts reasonably and in compliance with the Standards of Conduct to produce the lowest possible costs for ratepayers.[161]

# IV. DISCUSSION AND ANALYSIS

## A. Discussion

In the 2015 Record Period, SCE executed 42 contract amendments which resulted in a change to the notional value of the underlying PPA. Of these 42 amendments, four [redacted], one amendment [redacted] 22 resulted in [redacted], and 15 are Qualifying Facility (QF) contracts [redacted][162] The amendments with notional value changes are listed below, organized by notional value change:

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[157] D.02-10-062, p. 74.

[158] D.05-01-054, p. 14.

[159] D.02-12-074, p. 54.

[160] *Id.*

[161] *Id.*

[162] SCE Response to Data Request 08, Question 6.

**Table 5-1: SCE Contract Amendments from Record Period 2015 Resulting in Changes to the Notional Value of the Underlying PPA (Confidential)**

| | |
|---|---|
| [redacted] | |
| [redacted] | [redacted] [redacted][163] [redacted][164] |
| [redacted] | [redacted][165] |
| [redacted] | [redacted][166] |
| [redacted] | [redacted][167] |
| [redacted] | |
| [redacted] | [redacted][168] |
| [redacted] | |
| [redacted] | [redacted][169] |
| [redacted] | [redacted][170] |
| [redacted] | [redacted][171] |
| [redacted] | [redacted][172] |
| [redacted] | [redacted][173] |
| [redacted] | [redacted][174] |

[163] RAP ID refers to SCE's contract numbering convention and stands for Renewable and Alternative Power Identification. (A.16-04-001, Chapter VII Testimony, p. 124.)

[164] A.16-04-001, Chapter VII Testimony, p. 133.

[165] *Id.* p. 152.

[166] *Id.* p. 157.

[167] *Id.* p. 164.

[168] *Id.* p. 159.

[169] *Id.* p. 115.

[170] *Id.* p. 180.

[171] *Id.* p. 155.

[172] *Id.*

[173] *Id.*

[174] *Id.*

| | |
|---|---|
| 12 | FTS Master Tenant 1, LLC (ESB), Amendment 2 (RAP ID 5478)[175] |
| 13 | SEPV Palmdale East, LLC, Amendment 2 (RAP ID 5745)[176] |
| 14 | Citizen Solar B, LLC, Amendment 2 (RAP ID 5756)[177] |
| 15 | Citizen Solar B, LLC, Amendment 3 (RAP ID 5756)[178] |
| 16 | Wildwood Solar I, LLC, Amendment 4 (RAP ID 5757)[179] |
| 17 | NRG Solar Oasis, LLC, Amendment 2 (RAP ID 5774)[180] |
| 18 | CED Atwell Island West, LLC, Amendment 2 (RAP ID 5777)[181] |
| 19 | SEPV Mojave West, LLC, Amendment 1 (RAP ID 5778)[182] |
| 20 | Adera Solar, LLC, Amendment 1 (RAP ID 5781)[183] |
| 21 | SunEdison Utility Solutions, LLC (SunE – Mira Loma), Amendment 1 (RAP ID 5789)[184] |
| 22 | SunE DB22, LLC, Amendment 1 (RAP ID 5790)[185] |
| 23 | Sestina Solar II, LLC, Amendment 1 (RAP ID 5791)[186] |
| 24 | SunE Solar XVIII Project 1, LLC, Amendment 1 (RAP ID 5794)[187] |
| 25 | SunE DB13, LLC, Amendment 1 (RAP ID 5795)[188] |

[175] *Id.*

[176] *Id.* p. 158.

[177] *Id.* p. 160.

[178] *Id.*

[179] *Id.*

[180] *Id.* p. 161.

[181] *Id.*

[182] *Id.* p. 162.

[183] *Id.*

[184] *Id.*

[185] *Id.*

[186] *Id.* p. 163.

[187] *Id.*

[188] *Id.*

| | |
|---|---|
| 26 | SunE DB14, LLC, Amendment 1 (RAP ID 5796)[189] |
| 27 | RE Tranquility, LLC, Amendment 1 (RAP ID 5811)[190] |
| QF Contracts [redacted] | |
| 28 | AltaGas Pomona Energy, Inc., Letter Agreement (RAP ID 2050)[191] |
| 29 | Ridgetop Energy LLC I, Amendment 6 (RAP ID 6024)[192] |
| 30 | Ridgetop Energy LLC I, Amendment 7 (RAP ID 6024)[193] |
| 31 | Ridgetop Energy LLC I, Amendment 8 (RAP ID 6024)[194] |
| 32 | Wind Stream Operation LLC, Amendment 7 (RAP ID 6042)[195] |
| 33 | AES Tehachapi Wind, LLC 85-A, Amendment 6 (RAP ID 6043)[196] |
| 34 | AES Tehachapi Wind, LLC 85-B, Amendment 6 (RAP ID 6044)[197] |
| 35 | NAWP Inc./Yavi Energy Inc., Amendment 3 (East Winds Project) (RAP ID 6052)[198] |
| 36 | NAWP Inc./Yavi Energy Inc., Amendment 4 (East Winds Project) (RAP ID 6052)[199] |
| 37 | NAWP Inc./Yavi Energy Inc., Amendment 5 (East Winds Project) (RAP ID 6052)[200] |
| 38 | Corum Energy, LLC, Amendment 6 (RAP ID 6055)[201] |
| 39 | Edom Hills Project 1, LLC, Amendment 4 (RAP ID 6056)[202] |

[189] *Id.* p. 164.

[190] *Id.* p. 165.

[191] *Id.* p. 129.

[192] *Id.* p. 131.

[193] *Id.*

[194] *Id.*

[195] *Id.*

[196] *Id.* p. 132.

[197] *Id.*

[198] *Id.*

[199] *Id.*

[200] *Id.*

[201] *Id.* p. 133.

[202] *Id.*

| | |
|---|---|
| 40 | Energy Development and Construction Company, Amendment 2 (RAP ID 6062)[203] |
| 41 | Section 22 Trust (San Jacinto), Amendment 2 (RAP ID 6094)[204] |
| 42 | Westwind Association, Amendment 3 (RAP ID 6096)[205] |

According to SCE, none of its contract amendments executed in the 2015 Record Period had been previously approved through a separate application or any other Commission mechanism.[206] SCE was therefore seeking approval through the ERRA application. However, this information came from a data request response and was not explicitly stated in the testimony. In order for ORA to give the necessary attention to the amendments in order to determine whether they should be approved, ORA recommends that SCE clearly state which amendments require Commission approval through the ERRA application.

Additionally, ORA reviewed the following six contracts to determine whether SCE complied with the SOC4 reasonableness standard:

**Table 5-2: Other Contract Administration Activity from Record Period 2015**

| Uncontrollable Force (Force Majeure) | |
|---|---|
| 1 | Geysers Power Company, LLC (RAP ID 3107)[207] |
| 2 | Desert Sunlight 250 (RAP ID 5217)[208] |
| 3 | Catalina Solar 2, LLC (RAP ID 5755)[209] |
| 4 | Ormesa Geothermal 1 (RAP ID 3104)[210] |

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[203] *Id.*

[204] *Id.* p. 134.

[205] *Id.* p. 135.

[206] SCE Response to Data Request 08, Question 5.

[207] A.16-04-001, Chapter VII Testimony, p. 175.

[208] *Id.*

[209] *Id.* p. 174.

[210] *Id.* p. 137.

| Contract Terminations Resulting in Notional Value Change | |
|---|---|
| 5 | Zuni Solar North (RAP ID 5654)[211] |
| 6 | Zuni Solar South (RAP ID 5655)[212] |

**B. Analysis**

ORA used the following standards of review to evaluate SCE's activities regarding its administration of contract amendments that resulted in an increase to the notional value:

i.) What are the actual and/or notional values of the contract amendments?

ii.) How are the actual and/or notional values accounted for in the utility's expense and/or revenue accounts?

iii.) Did the utility adequately justify or explain the rationale for the contract amendments, either in the application, testimony, Master Data Request (MDR), or data requests?

iv.) Were the amendments motivated by operational needs, such as obtaining more cost-effective resources, lower market prices, or by developer's request?

v.) Do the amendments reflect the ratepayers' and/or stakeholders' best interests?

ORA reviewed SCE's testimony and supplemental testimony, Master Data Request responses, supplemental data request responses, workpapers, past ERRA testimony, and prior Commission decisions. ORA also met with representatives from SCE's Energy Contracts, Compliance and Analysis, Energy Supply and Management, and Demand Side Management groups on May 26, 2016 to discuss SCE's broader contract administration processes.

Based on these communications and review of SCE's testimony, ORA provides the following analysis:

[211] *Id.* p. 181.

[212] *Id.*

**i.) Contract Amendments with Notional Value Changes**

Notional value changes are estimated at the time that parties execute contract amendments, so there are occasions when [redacted] once the amendments go into effect. The four amendments whose [redacted] demonstrate this. Amendment 1 of the contract between SCE and the Energy Development and Construction Company extended the delivery term of an earlier PPA to avoid the need to enter into a new contract.[213] Amendment 6 of the agreement between SCE and ORNI 18, LLC allowed [redacted][214] Amendment 2 of the contract between Coronal Lost Hills, LLC and SCE allowed [redacted][215] Amendment 1 between SCE and Copper Mountain Solar 4, LLC [redacted][216] Additionally, Amendment 2 between SCE and Catalina Solar 2, LLC [redacted][217] ORA finds these amendments to be reasonable.

Of the contracts that resulted in a reduction in the notional value, [redacted][218] [redacted][219] [redacted]

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[213] *Id.* p. 133.

[214] *Id.* p. 152.

[215] *Id.* p. 157.

[216] *Id.* p. 164-165.

[217] *Id.* p. 159.

[218] *Id.* p. 115-116.

[219] *Id.* p. 161, 180.

[redacted][220] [redacted][221] These notional value decreases are passed along as cost savings to ratepayers and all [redacted] ORA finds these amendments to be reasonable.

Finally, the 15 QF contract amendments in which [redacted].[222] ORA finds these amendments to be reasonable.

**ii.) Uncontrollable Force (Force Majeure)**

Four force majeure claims took place in Record Period 2015. Geysers Power Company, LLC experienced generator damage and outages as a result of last year's Valley Fire in Northern California.[223] Desert Sunlight, LLC [redacted][224] Catalina Solar 2, LLC claimed force majeure [redacted][225] [redacted][226] ORA finds that SCE managed these claims reasonably.

**iii.) Terminations Resulting in Notional Value Change**

Two contracts, Zuni Solar North and Zuni Solar South, were terminated on February 28, 2015 due to permitting issues.[227] However, [redacted]

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[220] *Id.* p. 155-156, 158-165.

[221] *Id.* p. 160, 162.

[222] *Id.* p. 129, 131-135.

[223] *Id.* p. 175.

[224] *Id.*

[225] *Id.* p. 174-175.

[226] *Id.* p. 137.

[227] *Id.* p. 181.

[redacted][228] Because there was no impact to ratepayers, ORA finds these terminations reasonable.

## V. CONCLUSION

Based on the analysis and evaluations delineated above, ORA does not object to SCE's request for approval of the contract amendments resulting in a change in the notional value of the underlying PPA. ORA also does not object to SCE's overall contract administration activities. However, ORA does recommend that the Commission order SCE to clearly indicate in future testimony which items were not previously approved in the Record Period or through any separate decision or resolution, and which items require Commission approval.

[228] SCE Response to Data Request 08, Question 6.

# CHAPTER 6: COMPLIANCE AUDIT OF THE ENERGY RESOURCE RECOVERY ACCOUNT (ERRA) AND OTHER BALANCING AND MEMORANDUM ACCOUNTS

(Witness: Brian Lui and Grant Novack)

## I. INTRODUCTION AND SUMMARY

In its Application, SCE requests the Commission find that SCE's procurement related expenditures and other operations for the 2015 Record Period of January 1 through December 31, 2015 complied with its adopted procurement plan, and verify SCE's entries in the Energy Resource Recovery Account (ERRA) and sixteen (16) other regulatory accounts (i.e. Balancing and Memorandum accounts). The ERRA accounting entries for the 2015 Record Period are summarized in Table 6-1, which shows an over-collected balance of $439.063 million as of December 31, 2015.

This chapter presents ORA's review of SCE's ERRA and 16 other balancing and memorandum accounts for the 2015 Record Period. ORA found no required accounting adjustments and no exceptions to the recovery requirements.[229] ORA found that the ERRA entries and the 16 other balancing and memorandum account entries are appropriate, correctly stated, and in compliance with applicable Commission decisions.

## II. DISCUSSION

### A. Energy Resource Recovery Account (ERRA)

The ERRA accounting entries for the 2015 Record Period are summarized in Table 6-1 below:

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[229] SCE's Greenhouse Gas Compliance Instrument procurement is addressed in ORA chapter 7.

**Table 6-1[230]**
**Energy Resource Recovery Account (ERRA)**
**Record Period 2015 ($000)**

| Description | | |
|---|---|---|
| Beginning Balance (1/1/15) | | 892,740 |
| Commission Authorized Transfers | | (616,752) |
| Significant Adjustments (Greater than $1 Million) | | (59,340) |
| Other Entries/Adjustments | | (1,100) |
| Adjusted Beginning Balance | | 215,548 |
| ERRA Revenue | (4,902,987) | |
| ERRA Expenses | 4,247,997 | |
| (Over)/Under Collection | | (654,990) |
| Interest | | 381 |
| Ending Balance (12/31/15) | | (439,063) |
| GHG Costs Subaccount w/Interest | | 0 |
| Total ERRA Ending Balance | | $(439,063) |

The ERRA is established pursuant to Decision (D.) 02-10-062.[231] The purpose of the ERRA is to record the difference between ERRA-related revenue and SCE's recorded fuel costs and purchased power-related expenses, excluding California Department of Water Resources (DWR) power contract expenses. Electric Energy Transaction Administration (EETA) costs should be excluded from the ERRA consistent with

[230] SCE Direct Testimony Table XI-13.

[231] D.02-10-062, p. 61.

D.02-12-074.[232] Pursuant to D.04-01-048, SCE is authorized to record the above-market cost of Qualifying Facilities and Purchase Agreements in the ERRA.[233]

### B. Recorded Greenhouse Gas (GHG) costs

The Greenhouse Gas (GHG) cost subaccount is established pursuant to D.12-12-033, Ordering Paragraph (OP) 20, to track and record GHG costs as a subaccount of ERRA. In October 2014, SCE switched from a cash basis to the accrual method of accounting for GHG compliance instruments costs pursuant to D.14-10-33 OPs 14 and 15. SCE's entries to the GHG Cost Subaccount for the 2015 Record Period are summarized in Table 6-2 below:

**Table 6-2[234]**
**GHG Cost Subaccount**
**Record Period 2015 ($000)**

| | |
|---|---|
| Beginning Balance 1/1/15 | 135,725 |
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| Transfer to ERRA[235] | (135,767) |
| Ending balance 12/31/15 | $ 0 |

### C. Regulatory Balancing, Memorandum, and Tracking Accounts

The revenue, expenses, and ending balances of the 17 ratemaking accounts for the applicable Record Periods are summarized in Table 6-3 (below):

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[232] D.02-12-074, p. 46.

[233] D.04-01-048, p. 24.

[234] SCE Response to ORA Data Request 18, Question 2.

[235] SCE Direct Testimony Chapter XI, pp. 24, lines 15 through 19.

**Table 6-3[236]**
**Applicable Ratemaking Accounts**
**($000)**

| Source: SCE-2 Table Number | Account | Beginning Balance 1/01/15 | Ending Balance 12/31/15 | Change |
|---|---|---|---|---|
| XI-13 | Energy Resource Recovery Account (ERRA) | 892,740 | (439,063) | (1,331,803) |
| XI-14 | Base Revenue Requirement Balancing Account (BRRBA) | (5,371) | (318,847) | (313,476) |
| XI-15 | Nuclear Decommissioning Adjustment Mechanism (NDAM) | (52,883) | (78,256) | (25,373) |
| XI-16 | Public Purpose Programs Adjustment Mechanism (PPPAM) | 131,634 | 314,251 | 182,617 |
| XI-17 | CARE Balancing Account (CBA) | (20,467) | (20,519) | 52 |
| XI-18 | New System Generation Balancing Account (NSGBA) | 34,742 | (170,971) | (205,713) |
| XI-19 | Medical Programs Balancing Account (MPBA) | (14,166) | (24,789) | (10,623) |
| XI-21 | Pensions Costs Balancing Account (PCBA) | (24,861) | 94 | 24,955 |
| XI-22 | Post Employment benefits Other than Pensions Balancing Account (PBOP BA) | (25,252) | (11,443) | 13,809 |
| XI-23 | Results Sharing Memorandum Account (RSMA) | 0 | 0 | 0 |
| XI-24 | Statewide Marketing, Education & Outreach Balancing Account (SME&OBA) | (1,333) | (3,617) | (2,284) |
| XI-25 | Energy Settlement Memorandum Account (ESMA) | (204,060) | (4,517) | 199,543 |

[236] SCE Direct Testimony Chapter XI and Chapter XII, pp. 20 – 90 and SCE Supplemental Direct Testimony pp. 1 – 12 filed on June 29, 2016.

| | | | | |
|---|---|---|---|---|
| XI-27 | Litigation Costs Tracking Account (LCTA) | 6,784 | 6,259 | (525) |
| XI-28 | Project Development Division Memorandum Account (PDDMA) | (6,785) | (4,906) | 1,879 |
| XI-30 | Renewables Portfolio Standard Costs Memorandum Account (RPSCMA) **2009 Record Period** | 0 | 188 | 188 |
| XI-30 | Renewables Portfolio Standard Costs Memorandum Account (RPSCMA) **2010 Record Period** | 188 | 692 | 504 |
| XI-30 | Renewables Portfolio Standard Costs Memorandum Account (RPSCMA) **2011 Record Period** | 692 | 693 | 1 |
| XI-30 | Renewables Portfolio Standard Costs Memorandum Account (RPSCMA) **2012 Record Period** | 693 | 694 | 1 |
| XI-30 | Renewables Portfolio Standard Costs Memorandum Account (RPSCMA) **2013 Record Period** | 694 | 781 | 87 |
| XI-30 | Renewables Portfolio Standard Costs Memorandum Account (RPSCMA) **2014 Record Period** | 781 | 1,020 | 239 |
| XI-30 | Renewables Portfolio Standard Costs Memorandum Account (RPSCMA) **2015 Record Period** | 1,020 | 1,021 | 1 |
| XII-31[237] | Pole Loading and Deteriorated Pole Balancing Account (PLDPBA) | 0 | (36,181) | (36,181) |
| II-2[238] | Department of Energy Litigation Memorandum Account (DOELMA) **2012** | 0 | 113 | 113 |

[237] SCE Direct Testimony Chapter XII, pp. 85.

[238] SCE Supplemental Direct Testimony pp. 1 – 12 filed on June 29, 2016.

| | | | | |
|---|---|---|---|---|
| | **Record Period** | | | |
| II-2 | Department of Energy Litigation Memorandum Account (DOELMA) **2013 Record Period** | 113 | 197 | 84 |
| II-2 | Department of Energy Litigation Memorandum Account (DOELMA) **2014 Record Period** | 197 | 694 | 497 |
| II-2 | Department of Energy Litigation Memorandum Account (DOELMA) **2015 Record Period** | 694 | 1,801 | 1,107 |
| II-2 | Department of Energy Litigation Memorandum Account (DOELMA) **2016**[239] **Record Period** | 1,801 | (122,180) | (123,981) |

### D. Requested 2017 Revenue Requirement Change

SCE is seeking a net revenue decrease in 2017 of $0.082 million, including franchise fees and uncollectibles (FF&U) associated with two (2) accounts. During the 2015 Record Period, one account authorized by the CPUC was under-collected: the Renewables Portfolio Standard Costs Memorandum Account (RPSCMA). Also during the 2015 Record Period, one account authorized by the CPUC was over-collected: the Project Development Division Memorandum Account (PDDMA). The requested $0.082 million represents the remaining costs associated with the under-collected account after offset with the over-collected account. A summary of SCE's requested net revenue decrease is shown in Table 6-4 below:

[239] SCE Supplemental Direct Testimony pp. 2, line 7 -12. Filed on June 29, 2016.

**Table 6-4**[240]
**Summary of Requested 2017 Revenue Requirement Change**
**($000)**

| Balancing and Memorandum Accounts | | Revenue Change |
|---|---|---|
| (1) Project Development Division Memorandum Account | | -1,102 |
| (2) Renewables Portfolio Standard Costs Memorandum Account | | 1,021 |
| Total Net Over-Collection | | -81 |
| FF&U | | -1 |
| Total Revenue Requirement Change - Decrease | $ | -82 |

## III. AUDIT OBJECTIVES, SCOPE AND PROCEDURES

ORA reviewed SCE's ERRA and 16 other balancing and memorandum accounts for the 2015Record Period. The objective of ORA's review was to determine whether entries recorded in the ERRA and the 16 other balancing and memorandum accounts were appropriate, correctly stated, and in compliance with applicable Commission decisions. ORA's audit procedures included, but were not limited to the following:

- Reviewing SCE's application testimony, exhibits, workpapers, and data request responses.
- Reviewing applicable Advice Letters and Commission Decisions.
- Performing analytical reviews of monthly entries, including reviews of monthly balances recorded for each of the balancing and memorandum account tariff line items during the year, and evaluating monthly and annual fluctuations.
- Selecting a sample of balancing and memorandum account monthly and tariff line items to determine whether adequate support exists. ORA examined invoices, journals, general ledger entries, etc. for amounts recorded in the balancing and memorandum accounts and verified the mathematical accuracy of accounting worksheets and supporting documentation. ORA also visited SCE's offices to review and discuss each of the selected balancing and memorandum monthly and tariff line items in detail with SCE staff and to trace those line items to supporting documents.

[240] SCE Direct Testimony Table XI-11.

- Reviewing Monthly Interest Rates used and the interest amount calculations.
- Reviewing to determine whether revenues and costs recorded were appropriate and correctly stated.
- Reviewing to determine whether SCE complied with applicable Commission Decisions and Advice Letter Resolutions.
- Reviewing copies of internal audit reports[241] issued during the 2015 Record Period related to balancing account administration (reports listed in SCE Chapter 13).

On a judgment sample test basis, ORA reviewed those source documents that support the revenues, costs,[242] and expenses recorded in the ERRA. A "judgment sample" is a type of nonrandom sample selected by the auditor based on the judgment (opinion) of the auditor. Factors considered when selecting a judgment sample include auditor judgments about various elements including but not limited to the internal control environment, exposure/materiality, risk, and results of analytical reviews. ORA's judgement sample consisted of 32 monthly/tariff line items recorded in the ERRA.

ORA applied a similar sample test-basis audit methodology to review the supporting documentation for the revenues, costs and expenses recorded in the 16 other balancing and memorandum accounts.

## IV. CONCLUSIONS AND RECOMMENDATIONS[243]

A. ORA found that SCE appropriately operated the balancing, memorandum, and tracking accounts during the 2015 Record Period, and that the recorded entries in these accounts were appropriate, correctly stated, and in compliance with applicable Commission decisions.

B. ORA concludes that SCE's requested total net revenue change (decrease of $0.082 million) in 2017 as shown in ORA Table 6-4, which pertains to the recorded costs

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[241] Includes SCE Direct Testimony Section XIII. 2016 ERRA Review – ERRA-Related Audit Testimony.

[242] Includes CAISO-related costs also shown in SCE Direct Testimony Table X-10.

[243] As previous stated in footnote 1, SCE's Greenhouse Gas Compliance Instrument procurement is addressed in ORA chapter 7.

and revenues of two, is supported and correctly stated.  ORA does not object to SCE's request for approval of the $0.082 million net revenue requirement decrease.

# CHAPTER 7: GREENHOUSE GAS COMPLIANCE

(Witness: Tom Gariffo)

## I. SUMMARY

In the 2015 Record Period from January 1, 2015 through December 31, 2015, SCE incurred greenhouse gas (GHG) direct compliance costs of [redacted] for compliance with the California Air Resources Board (ARB) Cap-and-Trade Regulation.[244] ORA reviewed SCE's reported compliance costs, GHG compliance instrument procurement, 2015 Quarterly Compliance Reports (QCRs), Procurement Review Group (PRG) meeting materials, and data request responses. ORA is satisfied that SCE procured GHG compliance instruments in accordance with its approved GHG Procurement Plan within its Bundled Procurement Plan (BPP). ORA also reviewed SCE's GHG compliance instrument procurement strategy. Based on its review, ORA has no objection to SCE's request that the Commission find SCE's GHG procurement activity for the 2015 Record Period reasonable and within its procurement authority. SCE submitted its Energy Resource Recovery Account (ERRA) Review of Operations 2015 testimony in April of 2016 and Supplemental Direct Testimony in June of 2016, but neither provided sufficient information to determine if SCE's GHG compliance costs and procurement activities for the 2015 Record Period were reasonable and within its procurement authority. The data used to ascertain SCE's compliance came from data requests and from SCE's Supplemental Testimony filed on June 29, 2016. In future ERRA Review filings SCE should include with its GHG compliance chapter workpapers demonstrating facility-level generation and emissions data to justify GHG compliance costs, as well as a showing of indirect GHG compliance costs and associated data.

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[244] Direct SCE 2015 ERRA Testimony Table I-1, line 14.

## II. BACKGROUND

### A. California Air Resources Board Cap and Trade Program

The ARB Cap and Trade program is a market based regulation that is designed to reduce GHG from multiple sources. It covers about 450 entities. The program is designed to meet the goal of reducing GHG emissions to 1990 levels by the year 2020. ARB has three main responsibilities under the Cap-and-Trade program: (1) cap GHG emissions by issuing a number of tradeable permits (allowances) equal to the emission cap; (2) reduce the cap over time to reach 1990 emissions by 2020; and (3) enforce the cap by requiring each entity to turn in one allowance for every metric ton of carbon dioxide gas equivalent ($MTCO_2e$) that an entity emits.

The Cap and Trade program is structured into three compliance periods:

- First compliance period: 2013-2014
- Second Compliance period: 2015-2017
- Third Compliance period: 2018-2020

Compliance with Cap-and-Trade began in 2013 for electricity generators and large industrial facilities emitting 25,000 $MTCO_2e$ or more annually (covered entities).[245] Covered entities must report their emissions to ARB annually and those are verified through an independent third-party verification process.

Under ARB regulations, covered electric utilities are subject to specific compliance requirements and obligations.[246] To meet its compliance obligation an entity can use California GHG emission allowances or offset credits (offsets are limited to 8% of an entity's obligation per compliance period). An entity may bank allowances from previous vintage years, but not borrow from future vintage years to meet a compliance

[245] Starting in 2015, the program expanded to cover distributors of transportation, natural gas, and other fuels.

[246] A compliance obligation is the quantity of verified reported emissions or assigned emissions for which an entity must submit compliance instruments to ARB.

obligation.[247] Table 7.1 below shows what vintage year allowances may be used to meet an annual or triennial compliance obligation.

**Table 7.1: Eligible Allowance Vintage for Cap and Trade, Second Compliance Period**

| Second Compliance Period | | | |
|---|---|---|---|
| Covered Emissions Year | Compliance Obligation Due Date | Percent of Compliance Obligation Due | Eligible Vintages of Allowances |
| 2015 | November 1, 2016 | 30% of 2015 covered emissions | Vintages 2013-2015, any combination |
| 2016 | November 1, 2017 | 30% of 2016 covered emissions | Vintages 2013-2016, any combination |
| 2017 | November 1, 2018 | 70% of 2015 and 2016, and 100% of 2017 covered emissions | Vintages 2013-2017, any combination |

Under ARB reporting requirements, for the 2015 emissions year, facilities and suppliers are required to submit their GHG emissions reports by April 11, 2016, and June 1, 2016 for power entities; verified data (by independent evaluators) are due to ARB on September 1, 2016; and the Cap-and-Trade Compliance deadline is November 1, 2016. Entities must surrender sufficient compliance instruments to cover 30% of their qualifying emissions by November 1, 2016.

In addition to the compliance obligation associated with utility-owned facilities (for facilities that emit at least 25,000 $MTCO_2e$ per year), electric utilities are also responsible for imported electricity.[248] Under the Cap and Trade regulations utilities can apply a Renewables Portfolio Standard (RPS) Adjustment for electric imports from

[247] Section 95856 of the Cap-and-Trade Regulation. "To fulfill a compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year for which an annual compliance obligation is calculated or the last year of a compliance period for which a triennial compliance obligation is calculated."

[248] Also, an electric utility is responsible for GHG compliance costs for GHG emissions associated with contracts, where a utility has assumed the cost of compliance on behalf of a third-party (either agreeing to compensate a third-party for the costs of their compliance obligations or where a the utility is responsible for procuring compliance instruments on the third-party behalf).

unspecified sources, where the electricity is not directly delivered to California.[249] For electric power entity data reports, the deadline for corrections to the RPS Adjustment is due to ARB on July 15, 2016.[250]

# III. CPUC DECISIONS

## A. Procurement of GHG Compliance Instruments

Decision (D.)12-04-046 (Decision on System Track I Rules and Rules Track III of the Long-Term Procurement Plan Proceeding and Approving Settlement) Ordering Paragraph (OP) 8 authorizes the electric utilities to procure GHG allowances, allowance futures and forwards, and offsets and offset forwards within separately calculated Direct Compliance Obligation Purchase limits and Financial Exposure Purchase Limits, as set forth in Appendix 1 of the Decision.[251]

The Direct Compliance Obligation Purchase Limit sets the maximum amount of compliance instruments an Investor-Owned Utility (IOU) is allowed to purchase in the current year. Note that under this framework, the IOUs are not allowed to purchase allowances with vintages more than three years from the current year. The annual Direct Compliance Obligation Purchase Limit is calculated based on the following formula:

LCY = A + 100% * FDCY + 60% * (FDCY + 1) + 40% * (FDCY + 2) + 20% * (FDCY + 3)

Where:

"L" is the maximum number of GHG compliance instruments an IOU can purchase for purposes of meeting their direct compliance obligation.

[249] The RPS Adjustment decreases an entity's compliance obligation based on low-carbon or emissions-free power generation that it is responsible for and happens entirely outside of California.

[250] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-dates.htm.

[251] "Direct Compliance Obligation" is defined as the tons of emissions for which the utility has an obligation to retire allowances on its own behalf as a regulated entity under the Cap and Trade regime, and/or is otherwise obliged to procure instruments on behalf of a third party that is a regulated entity under the Cap and Trade regime (e.g. contractual arrangements where the IOU is responsible for procuring allowances on a third party's behalf, or could elect to assume that responsibility). Appendix 1, D. 12-04-046.

"A" is the utility's net remaining compliance obligation to date, calculated as the sum of the actual emissions for which the utility is responsible for retiring allowances (or purchasing on behalf of a third party) up to the Current Year, minus the total allowances or offsets the utility has purchased up to the Current Year that could be retired against those obligations.

"FD" is the utility's forecasted compliance obligation, the projected amount of emissions for which the utility is responsible for retiring allowances, or responsible for purchasing on behalf of a third party, calculated using an implied market heat rate (IMHR) that is two-standard deviations above the expected IMHR.

"CY" is the current year, i.e., the year in which the utility is transacting in the market.

**B. GHG Emissions**

Decision 15-01-024 requires the electric utilities to calculate and report the GHG emissions and associated costs using specific conventions and methodologies.[252] Utilities incur GHG costs directly (referred to here as "Direct GHG Cost") for purchasing compliance instruments for their own direct GHG emissions under the Cap-and-Trade program, and indirectly (referred to here as "Indirect GHG Cost") through GHG Cap-and-Trade costs embedded in the prices of the wholesale market.

A utility's **direct GHG emissions**, expressed in metric tons of carbon dioxide equivalents ($MTCO_2e$), could consist of the following sources (Refer to Figure 7.1 below for visual depiction of categories of GHG emissions and associated costs methodologies):

**(A) <u>Direct GHG Emissions with Physical Compliance Obligations:</u>**

**(1) Utility Owned Generation (UOG):** based on actual plant output, a facility-specific heat rate, and ARB-specific emissions factors of fuels; and

**(2) Energy Imports**: Specified imports based on actual plant output purchased by a utility and specific emissions factors; and Unspecified imports based on the ARB emission factor for unspecified imports, the ARB transmission loss factor, and any applicable RPS adjustment.

**(B) <u>Direct GHG Emissions Based on Contractual Obligations:</u>**

[252] D.15-01-024, Attachment D.

**(3) Qualifying Facility (QF) Contracts**: Physical settled emissions based on actual plant output purchased by a utility and the contract-specific settlement terms; and

**(4) Tolling Agreements:** based on actual plant output purchased by a utility, the resource-specific heat rate, and ARB-specific emissions factors for fuels.

**(C) <u>GHG Emissions Based on Financial Settlement Contracts:</u>**

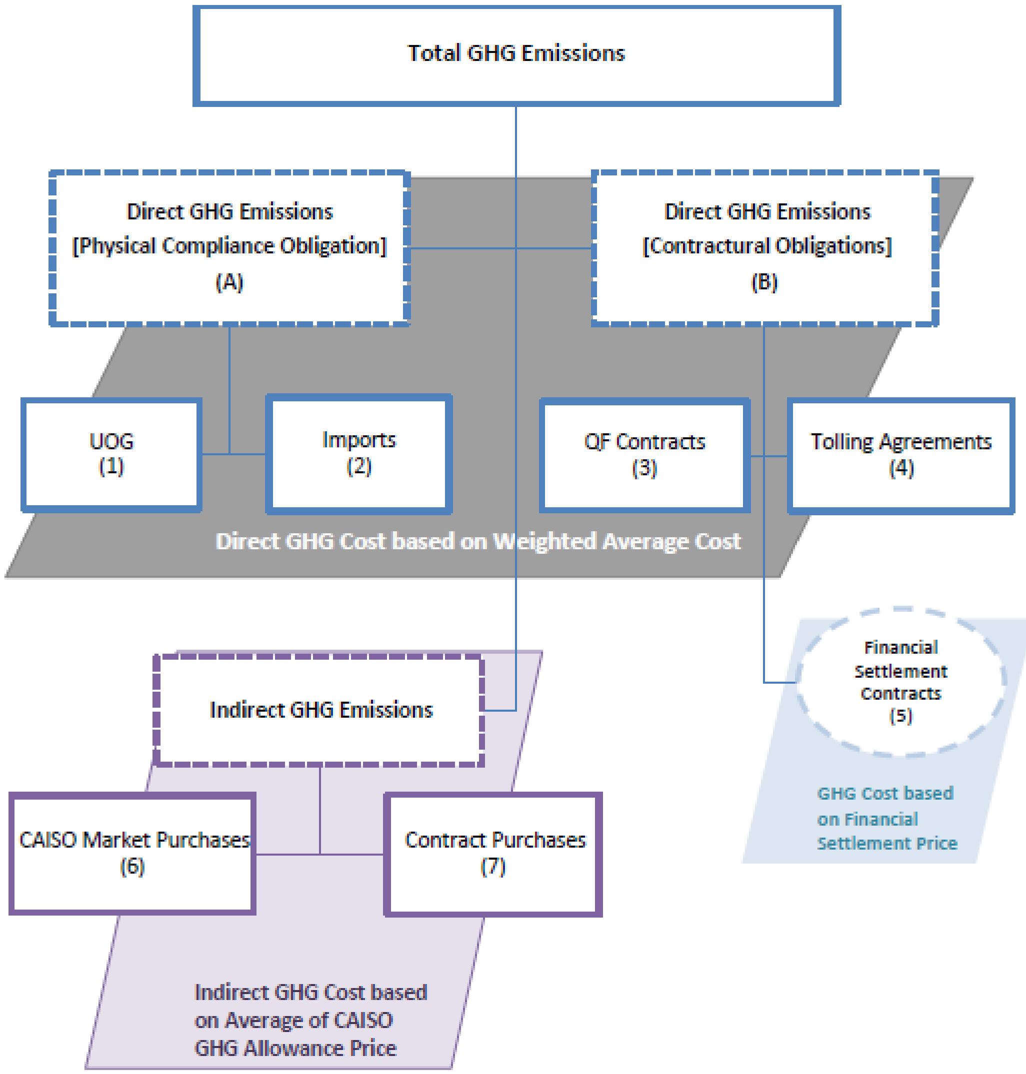
**(5) Contracts with Financial Settlements:** Emissions from utility contracts in which a utility is explicitly responsible for providing the financial settlement for GHG costs (utilities are allowed to record financially settled emissions as direct or indirect emissions).

A utility's **indirect GHG emissions**, expressed in $MTCO_2e$, could consist of the following sources (See Figure 7.1):

**(6) CAISO Market Purchases:** Emissions based on net market energy purchases and either ARB's emission factor for generic system power or a market heat rate-implied emission factor; and

**(7) Contract Purchases:** Emissions based on actual plant output purchased by the utility and contract-specific settlement terms where the responsibility for financial settlement of GHG costs is not explicitly addressed.

**Figure 7.1: Schematic of Direct and Indirect GHG Emissions and Methodology of Calculation of Asscoiated Costs by Type of Sources**




### C. GHG Emissions Costs

Decision 15-01-024 requires the electric utilities to calculate the recorded costs associated with GHG emissions covered by compliance obligations under the Cap-and-Trade program using the following methodologies:

**(A) <u>Direct GHG Costs:</u>**

The recorded direct GHG costs are the sum of each month's Weighted Average Cost (WAC) of compliance instruments inventory multiplied by that month's actual direct emissions for which the utility has a physical compliance obligation.[253] Thus, the direct GHG costs, based on WAC, could be applicable to GHG emissions from a UOG resource, imports, QF contracts, and tolling agreements, where a utility has physical compliance obligations.

For GHG emissions and costs associated with financially settled tolling agreements which a utility might record as direct emissions and costs, the recordings are based on actual contract settlement, not on WAC. These emissions and costs are therefore not included in the calculation of WAC or in the calculation of Direct GHG costs, which is based on monthly emissions.[254]

For the purpose of WAC calculations, a utility shall calculate the WAC based on its inventory of all allowances and offsets eligible to meet the compliance obligation for the current compliance period under the Cap-and-Trade program.[255] For instance, when calculating the WAC for 2015, a utility must calculate it based on inventory of allowances with vintage years 2015, 2016, and 2017, plus any 2013 and 2014 allowances that were not used to meet its obligation in the first compliance period. Under ARB regulations, there are no restrictions on which vintage year of offsets a utility can use to meet a compliance obligation.

**(B) Indirect GHG Costs:**

The recorded indirect GHG costs equal to the subtotal of indirect GHG emissions (CAISO market purchases and contract purchases) multiplied by the annual average of CAISO's daily GHG Allowance Price Index computed by averaging the published daily price for the recorded year and divided by the number of days in that year.

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[253] D.15-01-024 Attachment C.

[254] Direct Cost for Tolling Agreements with financial settlements = Settlement Price * Emissions Quantity; where settlement price is the unit price at which the utility will financially compensate its tolling counterparty for GHG (usually the ARB auction clearing price); and Emission Quantity is the emissions obligation for the entire month calculated in accordance with the tolling agreement.

[255] D.14-10-033, p. 23.

## IV. DISCUSSION

### A. SCE's Compliance Instrument Procurement for the 2015 Record Period is within the Procurement Limit Established in its BPP

During the 2015 Record Period, SCE procured [redacted] Vintage 2015 GHG allowances. [redacted] Per SCE Advice Letter 2958-E,[256] the most recent update to the procurement limits established in SCE's 2010 BPP, its direct GHG compliance obligation purchase limit for 2015 is [redacted].[257] SCE's total procurement of GHG compliance instruments in Record Year 2015 was within its 2015 GHG procurement limit. However, ORA questions the purpose and efficacy of a procurement limit that is [redacted], and recommends an extensive review of the data and methodology SCE employs in forecasting to generate this limit in the Integrated Resource Planning (IRP) proceeding.[258]

### B. SCE Procured GHG Compliance Instruments in the 2015 Record Period Pursuant with the Restrictions Established in its BPP on Where and How a Utility Can Procure GHG Compliance Instruments

During the 2015 Record Period, [redacted]

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[256] Data Request Set A. 16-04-001 ORA-SCE-9.3 "SCE's GHG instrument procurement limits for the 2015 Record Period were approved by the Commission in Advice Letter 2958-E."

[257] [redacted]

[258] The BPP was a track of the Long-Term Procurement Planning (LTPP) proceeding, which has now been rolled into the Integrated Resource Planning proceeding, Rulemaking 16-02-007.

[259] SCE's 2010 AB 57 Bundled Procurement Plan, Clean Version, p. 64.

[redacted] Record Period. Based on ORA's review of SCE's direct ERRA testimony, SCE's responses to ORA data requests, and SCE's QCR material from Record Period 2015, as well as ORA's participation in PRG meetings, SCE procured GHG compliance instruments during Record Period 2015 in accordance with its BPP.

### C. ORA Does Not Object to SCE's GHG Compliance Strategy for Record Period 2015

#### i. SCE Adequately Supported its Recorded Direct Costs and Forecasting Methodology for 2015

SCE reports in its 2015 Record Period direct ERRA testimony that it recorded [redacted] in Direct and Tolling Contract GHG Costs.[260] ORA issued a data request for verification of this figure. In response, SCE provided a breakdown of monthly emissions volume and recorded costs by UOGs, imports, and financial exposure. This information was also provided in the confidential workpapers accompanying SCE's supplemental testimony filing on June 29. ORA requested further data on the specifics of forecasted 2015 Record Period UOG fuel burn to produce emissions, specifically from the Mountainview Generating Station, SCE's only UOG surpassing the 25,000 MTCO2e annual emissions threshold to qualify for compliance. The recorded 2015 Record Period UOG compliance cost is reported at [redacted],[261] while the forecasted 2015 Record Period compliance cost for Mountainview is estimated at [redacted].[262] These recorded emissions are similar to ARB reported emissions at the Mountainview facility for the past two years.[263] SCE's recorded emissions from the generating resource, and the costs associated with them,

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[260] Direct SCE 2015 ERRA Testimony Table I-1, line 14. This number is rounded from [redacted].

[261] Data Request Set A. 16-04-001 ORA-SCE-9.1(a).

[262] Data Request Set A. 16-04-001 ORA-SCE-13.1(a).

[263] ARB reported emissions for Mountainview as 2.4 million in 2014 and 2.1 million in 2013.

therefore appear reasonable. Additionally, SCE's methodology for forecasting emissions from the generating resource appears sound.

#### ii. SCE's 2015 Record Period Compliance Instrument Procurements Appear to Be Reasonable and Not Detrimental to Ratepayers

For the first year of the cap-and-trade program's second compliance period, SCE is required to surrender compliance instruments for 30% of its 2015 emissions, with the remaining 70% due after 2017. To account for its 2015 compliance obligation, SCE would require around [redacted] allowances and offsets. As stated above, SCE procured [redacted] GHG allowances in the 2015 Record Period, which will be sufficient for the 2015 obligation. SCE also took delivery of over [redacted] GHG offsets in the 2015 Record Period.[264] In workpapers provided with its supplemental testimony, SCE reports a recorded direct 2015 GHG volume of [redacted] emissions in the 2015 Record Period.[265] Fulfilling the remaining 70% obligation would then require using roughly [redacted] earlier vintage allowances from SCE's existing inventory in addition to the [redacted] compliance instrument procurements made in the 2015 Record Period. As the price of GHG allowances generally increases over time, relying on larger procurements from earlier vintage allowances to meet future obligations can be a cost-effective strategy; this would also be beneficial for ratepayers if the procurements in a single Record Period are not so excessive as to create a burdensome rate increase during that year.

SCE procured allowances to meet its near-term obligation and to be well-positioned to meet the second compliance period obligation. However, ORA's review extends beyond whether or not a utility made purchases in accordance with regulation because the manner in which it chose to meet its compliance obligation affects its revenue requirement and rates. For GHG compliance, "SCE is not seeking direct

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[264] Data Request Set A. 16-05-001 ORA-SCE-1 Template C-1, 2015 SCE WAC calculation.

[265] Data Request Set A. 16-04-001 ORA-SCE-9.1(a).

recovery of the full cost of GHG compliance transactions that were undertaken during 2015. Rather, these transaction costs are inputs into the Weighted Average Cost calculations."[266] More expensive transaction costs result in a higher WAC, and because a utility's WAC price affects the forecasted costs for which it will be requesting recovery, the utility's execution of a procurement strategy has an ongoing impact on its current and future ERRA requests. Based on ORA's review, SCE made the necessary procurements while incorporating strategic procurements of less expensive offsets and early vintage allowances, and as such SCE appears to have conducted GHG procurement in a responsible and cost-conscious manner.

## V. CONCLUSION

ORA is satisfied that, for the 2015 Record Period, SCE has sufficiently proven that it procured GHG compliance instruments in accordance with its approved 2010 Bundled Procurement Plan and complied with the Commission's reporting requirements for utility procurement of GHG compliance instruments. Also based on ORA's review, the methods employed by SCE in the 2015 Record Period to record and forecast Direct GHG costs were reasonably accurate, and the procurements made as reported in QCRs for Q1 through Q4 applied a reasonable strategy to make cost-conscious procurements of GHG compliance instruments for ratepayers.

ORA understands the evolving nature of GHG regulatory compliance for IOUs, and recommends that SCE submit a more detailed filing addressing GHG costs and procurement in future compliance years. Pending Commission approval of the SCE/ORA Settlement Agreement in Application 15-04-002, future SCE ERRA Review showings "will provide testimony and workpapers on its Greenhouse Gas (GHG) compliance instrument purchases and sales conducted (and recorded costs incurred) during the relevant Record Period."[267] SCE voluntarily supplied ORA with supplemental

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[266] Data Request Set A. 16-04-001 ORA-SCE-9.2(a).

[267] A.15-04-002 Motion for Approval of Settlement Agreement Between Southern California Edison Company and the Office of Ratepayer Advocates, p. 7.

testimony complying with the Settlement Agreement on June 29, 2016, which included QCR GHG Emission transactions for Q1 through Q4 of 2015, Appendix I of the Conformed 2010 BPP pertaining to GHG procurement, and the workpaper underlying the Direct and Contract GHG Costs reported in Table I-1 of SCE's testimony. In order to adequately review GHG emissions and the associated costs incurred, ORA must be able to trace GHG emission quantities back to the power produced and/or fuel consumed at specific facilities for both UOG and Contracted resources. If SCE is unable to produce this information in the current Record Period, then it should submit the analogous data that was most recently used in forecasting the ERRA filing Record Period facility-level emissions. Due to their importance, SCE should include these data along with the other workpapers and supplemental information in its initial filing of ERRA testimony. Inclusion of this information in the upfront filing will create consistency for SCE that will provide more time to both ORA and SCE staff in the already compact ERRA Compliance review process.

ORA further recommends that SCE incorporate indirect GHG compliance costs in future ERRA Review testimony. Though indirect costs are embedded in the cost of purchased electricity, SCE is currently required to demonstrate an estimation of indirect GHG costs in ERRA Forecast filings.[268] To ascertain the accuracy of forecasted indirect emissions and costs coming into a Record Period, going forward ORA requests the associated data from the actual Record Period activity in ERRA Compliance testimony.

In summary, ORA recommends the following points regarding GHG compliance in this chapter of testimony:

- SCE sufficiently complied with the procurement requirements outlined in its BPP.
- SCE made and followed a strategy of GHG compliance instrument procurement in the 2015 Record Period that does not appear detrimental to ratepayers.

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[268] D.15-01-024 Attachment D, Template D-2 lines 9, 10, 11, 12, 18.

- There should be an extensive review of the data and methodology SCE employs in forecasting to generate its compliance instrument purchase limit in the Integrated Resource Planning (IRP) proceeding.
- To facilitate a thorough review of emissions, SCE should provide data with its ERRA filing referencing the power produced and/or fuel consumed at specific facilities for both UOG and Contracted resources in the Record Period.  If this data is unavailable, SCE should provide the power production and/or fuel consumption data most recently used to forecast the Record Period ERRA filing facility-level emissions.
- To verify the accuracy of its required forecast filing, SCE should include indirect GHG compliance costs in future ERRA Review testimony.

# APPENDIX A

# Qualifications of Witnesses

**QUALIFICATIONS AND PREPARED TESTIMONY**
**OF**
**RADU CIUPAGEA**

**Q.1 Please state your name and address.**

A.1 My name is Radu Ciupagea. My business address is Electricity Pricing and Customer Programs Branch, Office of Ratepayer Advocates, California Public Utilities Commission, 505 Van Ness Avenue, 4th floor, San Francisco, California.

**Q.2 By whom are you employed and in what capacity?**

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Office of Ratepayer Advocates (ORA) in the Electricity Pricing and Customer Program Branch.

Q.3 **Please describe your educational and professional experience.**

A.3 I hold two Bachelor of Arts Degrees, in Economics and French, respectively, from the University of California at Berkeley.

I have been employed by the California Public Utilities Commission since February 1, 2011. Since joining the CPUC, I have worked on Demand Response, low income energy efficiency, low-income subsidy programs, Long-Term Procurement Plan, Joint Reliability Plan, Integrated Resource Planning, and SCE Energy Resource Recovery Account.

**Q.4 What is your area of responsibility in this proceeding?**

A.4 I am responsible for Chapter 1 of ORA's testimony.

**Q.5 Does that complete your prepared testimony?**

A.5 Yes, it does.

**QUALIFICATIONS AND PREPARED TESTIMONY**
**OF**
**MEA HALPERIN**

**Q.1 Please state your name and business address.**

A.1 My name is Mea Halperin. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

**Q.2 By whom are you employed and in what capacity?**

A.2 I am employed by the California Public Utilities Commission (CPUC) as a Public Utilities Regulatory Analyst in the Office of Ratepayer Advocates' (ORA) Electricity Planning and Policy Branch.

**Q.3 Please describe your educational and professional experience.**

A.3 I hold a Master of Public Administration degree in Environmental Science and Policy from Columbia University and a Bachelor of Arts degree in Political Science from the University of California, Berkeley. I joined the Commission on November 5, 2015 in ORA's Electricity Planning and Policy Branch, where I am the witness for Least-Cost Dispatch and Contract Administration for both Pacific Gas and Electric and Southern California Edison's ERRA Compliance proceedings. Prior to working at the Commission, I managed research programs, provided financial analyses, and performed program evaluations for climate and agriculture research.

**Q.4 What is the scope of your responsibility in this proceeding?**

A.4 I am responsible for preparing Chapter 2: Least-Cost Dispatch and Chapter 5: Contract Administration and Costs.

**Q.5 Does this complete your testimony at this time?**

A.5 Yes.

**QUALIFICATIONS AND PREPARED TESTIMONY**
**OF**
**MICHAEL YEO**

**Q.1 Please state your name and business address.**

A.1 My name is Michael Yeo. My business address is 505 Van Ness Avenue, San Francisco, California.

**Q.2 By whom are you employed and in what capacity?**

A.2 I am employed by the California Public Utilities Commission as a Senior Utilities Engineer in the Office of Ratepayer Advocates (ORA).

**Q.3 Please describe your educational and professional experience.**

A.3 I graduated from the University Of Toronto with a Bachelor of Applied Science in Civil Engineering, and am a registered Professional Engineer. Since joining the Commission in 1992, I have worked in various assignments in ORA, Energy Division and the Consumer Protection and Safety Division. Immediately prior to joining the Commission, I worked for the California Department of Transportation.

**Q.4 What is the scope of your responsibility in this proceeding?**

A.4 I am responsible for Chapter 3, Utility-Owned Generation – Hydroelectric, and Chapter 4, Utility-Owned Generation – Natural Gas.

**Q.5 Does this complete your testimony at this time?**

A.5 Yes, it does.

**QUALIFICATIONS AND PREPARED TESTIMONY**
**OF**
**BRIAN LUI**

**Q.1 Please state your name and business address.**

A.1 My name is Brian Lui. My business address is 505 Van Ness Ave, San Francisco, California, 94102.

**Q.2 By whom are you employed and in what capacity?**

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Financial Examiner II in the Office of Ratepayer Advocates (ORA), Electricity Planning & Policy Branch.

**Q.3 Please describe your educational and professional experience.**

A.3 I received a Bachelors of Science Degree in Biochemistry from the University of California, Riverside. I also possess a Masters Degree in Accounting from Golden Gate University in San Francisco. I joined the Commission on January 7, 2014 in ORA's Electricity Planning and Policy Branch. In ORA, I am involved in the ERRA Forecast and ERRA Compliance proceedings. Immediately prior to joining the Commission, I worked for the California State Board of Equalization as a tax auditor. I have over 4 years of experience working as an auditor in the public sector.

**Q.4 What is the scope of your responsibility in this proceeding?**

A.4 I am co-sponsoring Chapter 6 of ORA's testimony on Compliance Audit of the Energy Resource Recovery Account (ERRA) and Other Balancing and Memorandum Accounts.

**Q.5 Does this complete your testimony at this time?**

A.5 Yes, it does.

**QUALIFICATIONS AND PREPARED TESTIMONY**
**OF**
**GRANT NOVACK**

**Q.1 Please state your name and business address.**

A.1 My name is Grant Novack. My business address is 505 Van Ness Ave, San Francisco, California, 94102.

**Q.2 By whom are you employed and in what capacity?**

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Financial Examiner IV in the Office of Ratepayer Advocates (ORA), Energy Cost of Service and Natural Gas Branch.

**Q.3 Please describe your educational and professional experience.**

A.3 I graduated from the University of Nevada, Las Vegas with a Bachelor of Science Degree in Business Administration. I am a Certified Internal Auditor. I joined the staff of the Commission in February 2003. I have 37 years auditing experience.

**Q.4 What is the scope of your responsibility in this proceeding?**

A.4 I am co-sponsoring Chapter 6 of ORA's testimony on the Compliance Audit of the Energy Resource Recovery Account (ERRA) and Other Balancing and Memorandum Accounts.

**Q.5 Does this complete your testimony at this time?**

A.5 Yes, it does.

**QUALIFICATIONS AND PREPARED TESTIMONY**
**OF**
**THOMAS GARIFFO**

**Q.1 Please state your name and business address.**

A.1 My name is Thomas Gariffo. My business address is 505 Van Ness Ave, San Francisco, California, 94102.

**Q.2 By whom are you employed and in what capacity?**

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst II in the Office of Ratepayer Advocates (ORA), Electricity Planning & Policy Branch.

**Q.3 Please describe your educational and professional experience.**

A.3 I hold a Master's of Public Policy from the Luskin School of Public Affairs at the University of California, Los Angeles, and a Bachelor of Arts in Political Science with a minor in Public Policy from the University of California, Berkeley. I have been employed by the California Public Utilities Commission in the Office of Ratepayer Advocates since September 1, 2015. Since joining CPUC I have worked on greenhouse gas programs, including the cap-and-trade program and low carbon fuel standards, as well as programs related to the deployment and support of electric vehicles.

**Q.4 What is the scope of your responsibility in this proceeding?**

A.4 I am responsible for Chapter 7 of ORA's testimony.

**Q.5 Does this complete your testimony at this time?**

A.5 Yes, it does.