BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 13-12-010 (Filed December 19, 2013)

**THE OFFICE OF RATEPAYER ADVOCATES' COMMENTS
ON THE PROPOSED BUNDLED PROCUREMENT PLANS OF
PACIFIC GAS AND ELECTRIC COMPANY,
SOUTHERN CALIFORNIA EDISON COMPANY, AND
SAN DIEGO GAS & ELECTRIC COMPANY
(PUBLIC VERSION)**

DIANA L. LEE
MATT MILEY
Attorneys

Office of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-4342
Fax: (415) 703-2262
Email: Diana.Lee@cpuc.ca.gov

NIKA ROGERS
PETER SPENCER
Analysts

Office of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-1529
Email: Nika.Rogers@cpuc.ca.gov

November 4, 2014

TABLE OF CONTENTS

I. INTRODUCTION

The Office of Ratepayer Advocates (ORA) submits the following comments on the draft Bundled Procurement Plans (BPPs) of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE).[1] ORA files these comments pursuant to the October 6, 2014 Administrative Law Judge's (ALJ) Ruling Seeking Comments on Bundled Procurement Plans as modified by Judge Gamson's October 13, 2014 email to the service list and docket office extending the dates for submitting opening comments until November 4, 2014, and the date for submitting reply comments to November 20, 2014. As explained in Section II below, ORA recommends that the Commission:

- Develop utility reporting requirements for non-compliant transactions;
- Conduct an independent expert review of the utilities' hedging plans to enhance regulatory oversight and provide guidance to the utilities;
- Incorporate Demand Response (DR) as part of Least Cost Dispatch (LCD);
- Rely on the mandated Trajectory Scenario for PG&E instead of PG&E's Alternative Scenario;
- Reject SCE's proposal to modify the consumer risk tolerance (CRT);
- Clarify the changes to the CRT adopted in Decision (D).12-01-033;
- Reject SCE's hedging proposal for failure to comply with Public Utilities Code Section 454.5;
- Defer consideration of SCE's proposal to streamline approval of short-term RPS contracts until after adoption of the pending Proposed Decision (PD) in the Renewables Portfolio Standard (RPS) Rulemaking (R.)11-05-005; and
- Require SDG&E to correct double counting of DR Programs.

II. BACKGROUND

Pursuant to Assembly Bill 57 as codified by Public Utilities Code Section 454.5, the Commission reviews and approves the three investor-owned utilities (IOUs or Utilities) bundled procurement plans (BPPs) in the Long-Term Procurement Planning (LTPP) proceeding. The Commission's review of the IOUs' BPPs establishes upfront standards and obviates the need for the Commission to conduct an after the fact reasonableness review. In the 2012 LTPP,

[1] ORA's confidential comments highlight confidential text in yellow. ORA's public comments redact confidential text by replacing it with black strike outs.

Rulemaking (R.)12-03-014, the IOUs were not ordered to file BPPs. As part of Phase 2 of this 2014 LTPP proceeding, R.13-12-010, the May 6, 2014 Scoping Memo directed PG&E, SDG&E, and SCE to submit their draft BPPs on October 3, 2014.[2] The Scoping Memo listed the following issues as within scope of the bundled procurement plans:

1. Maximum and minimum limits on the IOUs' forward purchasing of energy, capacity, fuel and hedges;
2. Specification of the products that the IOUs can purchase;
3. Specification of rules that, if followed, would exempt the IOUs from reasonableness review; and
4. An integrated plan to comply with state policies, including the Loading Order.

The May 6th Scoping Memo, directed the IOUs to base their forward energy and capacity tables on the assumptions from the Trajectory Scenario included in the Commission’s February 27, 2014 Ruling.[3] The Commission’s intention in requiring the IOUs to utilize the Trajectory Scenario is that the IOUs’ BPPs would be more easily comparable to one another. ORA reviewed the confidential BPPs of PG&E, SCE, and SDG&E and generally found that they were more consistent and comparable to one another than they were in past LTPPs and for the most part, are consistent with Commission requirements except as explained below.

III. DISCUSSION

A. Issues Common to all the IOUs Bundled Procurement Plans

1. The Commission Should Develop Utility Reporting Requirements for Non-Compliant Transactions

None of the IOUs’ draft Bundled Procurement Plans address how they should report non-compliant transactions to the Commission or the steps they should take after the discovery of non-compliant transactions. For example, PG&E’s Energy Resource Recovery Account (ERRA) Compliance filings for the 2012 and 2013 Record Years (Applications (A.)13-02-023 and A.14-02-008 respectively) noted that PG&E discovered multiple non-compliant hedging transactions in the course of a routine internal review. In response to PG&E’s discovery of the non-compliant hedging transactions, ORA filed testimony to clarify how the Utilities should

[2] Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, May 6, 2014, p. 11.

[3] Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, May 6, 2014, p. 9.

respond to such a scenario. ORA's ERRA testimony in A.13-02-023 and A.14-02-008 forms the basis of these comments. ORA recommends that the Commission direct the IOUs to take the following steps in the event that future non-compliant transactions are discovered:

1) A utility must report non-compliant transaction(s) to the Commission within four business days of identifying and verifying the occurrence of a non-compliant transaction. The report to the Commission should include a brief written description of the non-compliant transaction, detailing:

    - When the transaction(s) took place,
    - The type of transaction(s) involved,
    - The financial size of the transaction(s) and the net profit or loss at the time of this report, and
    - A brief discussion of the next steps in the utility's process to identify the root cause of the problem, and develop a corrective action plan to ensure that this problem does not reoccur.

2) Within thirty (30) business days of identifying and verifying non-compliant transaction(s), the utility should also provide a corrective plan of action.

3) In any case where non-compliant transaction(s) are discovered that do not fit within the category of: "unusual events, market dislocations, and emergencies," [4] the utility can exercise its judgment regarding the most prudent way to handle the transaction. Any losses resulting from a non-compliant transaction should be borne by the utility's shareholders, since the loss is the result of a failure in the utility's operations.

4) Utilities should schedule a Procurement Review Group (PRG) meeting as soon as practicable after discovery of any non-compliant transaction(s) to discuss the nature of the non-compliance and how the utility plans to resolve the issue to prevent a recurrence.

It is important that the Commission provide the Utilities with clear guidance on how to respond to the discovery of non-compliant transactions. ORA's research revealed that this area has not been addressed in previous BPPs. These recommendations are aimed at providing clear and consistent reporting mechanisms for non-compliant transactions that apply to all the IOUs, as well as guidance for handling the transactions.

[4] As noted in PG&E's July 25, 2014, Rebuttal testimony in A.14-02-008, p. 4-4, PG&E's Electric Portfolio Hedging Plan contains a provision that allows PG&E to conduct transactions that do not comply with its hedging plan under the category of "unusual events, market dislocations, and emergencies."

2. The Commission Should Provide Regulatory Oversight and Guidance Through an Independent Review of the Utilities' Hedging Plans

The Utilities' hedging strategies were first developed immediately following the California energy crisis in 2002. The Commission granted the Utilities the independence to develop strategies and implement hedging actions on behalf of their ratepayers. The Commission examined the idea of standardizing hedging practices but concluded that the unique situations of each utility required individualized approaches to hedging.[5]

The Commission's hedging oversight primarily consists of requiring the Utilities to use a To Expiration Value at Risk (TEVaR)[6] analysis and applying the Consumer Risk Tolerance (CRT). The CRT represents the price increase in utility bills that consumers are willing to tolerate and creates a target for hedging. The CRT, however, has not been well-developed in the Commission's proceedings. Each IOU calculates TEVaR values using unique software programs that utilize inputs and assumptions. The individual software programs are also used to assist the IOUs with a variety of hedging decisions such as the purchase selections among a myriad of hedging financial products. This process does not require Commission oversight or review, thus, there are no standardized assumptions nor is there any transparency into the IOU's assumptions for TEVaR calculations.

In addressing Commission oversight of hedging practices, D.03-10-058 stated, "In general, we expect SCE and California's other investor-owned electric utilities to have extensive knowledge of natural gas markets and more expertise about hedging in those markets than we do in the regulatory sphere."[7] That challenge remains true today. Neither Commission nor ORA staff has the necessary time nor expertise to perform a thorough review of the IOUs' hedging practices.

The most recent Commission decision on IOU hedging declined to order a detailed review of hedging practices while noting "[w]e may, however, consider undertaking a more

---

[5] D.07-12-052, p. 172.

[6] See D.07-12-052, p. 173, "The TEVaR represents an estimate, at a given confidence level, of the amount of electric rate increase that could occur due to changes in market conditions such as nuclear outage risk, hydro-power availability risk, electricity spot market price volatility, credit risk, and gas price volatility. For example, TEVaR 95% measures the maximum rate increase over the expected value with 95% confidence level (in other words, it is the 1-in-20 worst case scenario).

[7] D.03-10-058, p. 5.

comprehensive review of utility hedging practices in the future, as our practices under the LTPP stabilize."[8] The evolution of hedging practices began twelve years ago. It is time for this comprehensive review to take place in order for the Commission to ensure that hedging practices strike the correct best balance between price stability and cost to ratepayers.

ORA envisions a hedging assessment performed by an independent firm with the expertise to analyze all aspects of the Commission's hedging guidelines and the IOU's hedging practices. The goal of this assessment would be to provide the Commission a summary of the IOUs' current hedging practices and recommendations for improvements and the outcome of the review would guide future hedging practices and inform the Commission for future modifications to its hedging regulations and oversight. ORA recommends that the scope of the independent review should be developed by the Commission with input from stakeholders. When ORA analyzed the ratepayer impact of utility hedging practices in 2010, the combined cost of hedging by the IOUs was $1.7 billion dollars. The numbers should be lower now due to gas price stability and the higher CRT adopted in D.12-01-033.Ideally, the process could be completed in time for consideration in this or the next LTPP cycle. Depending on the results of the initial study, the Commission can determine whether another review would be useful, and if so, when it should be completed.

3. Demand Response Should be Considered Part of Least Cost Dispatch

a) Background of the LCD Standard

In D.02-10-062, the Commission set forth seven minimum standards of behavior to guide the IOUs' management of their portfolios of generation and contracted resources.[9] The fourth of these minimum standards, Standard of Conduct 4 (SOC 4) states: "the utilities shall prudently administer all contracts and generation resources and dispatch energy in a least-cost manner."[10] In subsequent decisions the Commission further elaborated on the definition of SOC 4. D.02-12-074 included the following explanation of SOC 4 in the Utilities' approved procurement plans:

> "Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching

---

[8] D.12-01-033, p. 28.

[9] D.02-10-062: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/20249.pdf pp. 51 ocs.cp.

[10] D.05-01-054, p. 13.

> dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. 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."[11]

This explanation thereby represented the "upfront standard" regarding prudent contract administration and the daily dispatch of energy under Public Utilities Code Section 454.5.

b) Recent Guidance on LCD Standard

The Commission provided its most recent guidance regarding the LCD standard in D.13-10-041, D.13-11-005, and D.14-07-006. These decisions corresponded to the ERRA compliance applications of PG&E, SCE and SDG&E respectively, for the Record Year 2010. All three decisions concluded that the current LCD showings are unsatisfactory and should be improved. For example, D.13-11-005 stated:

> "In conclusion, while we find in this decision that—in the absence of a showing to the contrary—SCE's LCD activities complied with its Conformed 2006 LTPP, we caution SCE to take seriously our concerns regarding the shortcomings of its showing on LCD. Our concern is that SCE not only plan to "get it right" and minimize procurement costs for the benefit of its customers, but that it verify that its plans and intentions have succeeded, and that it take corrective actions if its efforts fall short."[12]

The same decision explains how SCE should improve its LCD showing:

> "A complete showing of least cost dispatch by SCE should 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."[13]

These decisions demonstrate the need for the Utilities to improve their LCD showings in ways that have not been considered in previous ERRA compliance filings:

> "The most productive use of the annual ERRA compliance proceedings is to help SCE, as well as PG&E and SDG&E in their own proceedings, to identify best practices and areas for improvement when those

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

[12] D.13-11-005, pp.26-27; *see also* D.13-10-41, p. 26 and D.14-07-006, pp. 22-23 (reaching similar conclusions for PG&E and SDG&E).

[13] D.13-11-005, Conclusion of Law 5, p. 78; *see also* D.13-10-41, Conclusion of Law 4, p. 43 and D.14-07-006, Conclusion of Law 5, p. 33 (reaching similar conclusion for PG&E and SDG&E).

opportunities exist. We will emphasize this in future proceedings, while retaining the right and obligation to levy disallowances or penalties if warranted."[14]

The Commission should take this opportunity to improve the IOUs' LCD showings by including dispatchable Demand Response (DR) resources (resources used to reduce energy usage during peak hours) within their LCD showings.[15]

c) ORA Recommendations

In order to demonstrate compliance with the goal of LCD, ORA recommends evaluating all dispatchable resources under the Commission's LCD standard, including DR resources with an economic trigger. Decisions D.13-10-041, D.13-11-005, and D.14-07-006 related to Record Year 2010. These decisions ordered the Utilities work together in workshops with other interested parties "to develop proposed criteria that should be used to determine what constitutes LCD compliance".[16] The Utilities and interested parties participated in the required workshops on January 22, 2014 (PG&E proceeding),[17] February 25, 2014 (SCE proceeding), October 15, 2014 (SDG&E proceeding). Based on the workshops and subsequent analysis, ORA recommends that the Commission require the Utilities to meet the following requirements in order to demonstrate LCD compliance for their DR programs.

1. All dispatchable resources, including dispatchable DR resources that respond to economic triggers, should be considered part of the Utilities' demonstration of LCD under SOC 4.
2. The Utilities should incorporate an annual summary of the results of the reporting requirement (related to dispatch of DR resources) recently adopted in D.14-05-025,[18] into the LCD showing of their ERRA compliance filings. At a minimum, for all dispatchable DR programs with an economic trigger, the Utilities must provide an annual summary of:
    a. The times and duration that all programs were dispatched each month;

[14] D.13-11-005, p. 27.

[15] CPUC Website, Demand Response Section, retrieved from: http://www.cpuc.ca.gov/PUC/energy/Demand+Response, on 5/7/2014.

[16] D.13-10-41, p.2; D.13-11-005, p. 2; D.14-07-006, p. 2

[17] Post-workshop report can be accessed at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M089/K304/89304980.PDF, retrieved 10/30/2014.

[18] D.14-05-025 calls for all three Utilities to comply with the reporting requirement, p. 16.

b. All cases where the DR program's trigger conditions were forecast to be met, and all cases where these trigger conditions were actually recorded;

c. A list of occurrences when DR resources should have been dispatched, according to their economic trigger conditions, but were not.

d. A detailed explanation for each case in which a DR resource was not called/dispatched when its trigger conditions had been met.

3. The Utilities should also provide a cost-based assessment to quantitatively demonstrate that DR resources achieved LCD, including but not limited to an assessment of:

   a. The total capacity of DR programs dispatched compared to their maximum available amount (monthly and annually).

   b. Whether the selection of DR events called minimized the utility's overall portfolio costs of dispatch.

4. An explanation of any internally developed metrics, such as opportunity cost indices, used to guide the DR dispatch decision.

B. Issue Specific to PG&E's Bundled Procurement Plan: the Commission Should Not Adopt PG&E's Alternative Scenario

The May 6, 2014 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge directed the IOUs to utilize the Commission's Trajectory Scenario for their bundled procurement plans when forecasting their energy and capacity needs over the ten-year period 2015 – 2024.[19] The Commission's goal in requiring the IOUs to utilize the Commission-mandated assumptions from the Trajectory Scenario in their forecasts was to facilitate comparison of the IOUs' plans. Although the Trajectory Scenario is the preferred reference case, the May 6th Scoping Memo also permitted the IOUs to provide a supplemental or alternative scenario using different assumptions and load growth projections.[20]

PG&E was the only IOU to submit an alternative scenario, which included modified assumptions for departing load and distributed generation. In the Alternative Scenario, PG&E estimated a significant reduction in its forecasted electricity demand, particularly due to growth in existing and new Community Choice Aggregators (CCAs) as well as a considerable growth in

[19] Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, May 6, 2014, p. 9.

[20] R Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, May 6, 2014, p. 9.

behind the meter distributed generation (DG) over the next ten years.[21] PG&E based its CCA load departure estimates on its load growth expectations for the two active CCAs, Marin Clean Energy and Sonoma Clean Power, as well as probability and opt out factors assigned to potential CCAs implementers, including San Francisco County and a few other regions that PG&E states are "seriously" exploring establishing CCAs.[22] PG&E based its DG trends on recent growth in the photovoltaic (PV) market, which it believes will continue to increase, albeit at a slower rate after 2018.[23] PG&E justifies using these assumptions in its Alternative Scenario because these factors were not accounted for in the Commission's Mandated Scenario.[24]

PG&E has not adequately justified its proposed departure from the Trajectory Scenario. Pending more accurate data from the CEC, ORA finds that the alternative assumptions PG&E utilized to calculate departing load and the growth of DG are too speculative at this time to warrant an endorsement of this scenario for PG&E's 2014 BPP ten-year load forecast. Furthermore, PG&E's alternative forecast for DG growth, based on a comparison of retail electric rates with prices offered by third party solar providers rather than consumer response to a payback calculation, appears to selectively update some but not all DG parameters. The projected growth of the departing loads, propelled by inputs with a large degree of uncertainty[25] should not be accepted at this time since this process will recommence in the next LTPP cycle, slated for 2016. Instead, ORA recommends the Commission rely on the Trajectory Scenario/CPUC Mandated Scenario for PG&E's ten-year forward energy and capacity projections.

---

[21] For example, the CCA, DA, and DG Alternative (Energy Balance) sum for 2015 is 22,084 GWh, whereas the sum for the same year in the Mandated scenario is 13,919 GWh. For 2024, the same loads total 40,229 GWh for the Alternative compared to 15,353 GWh presented in the Mandated Scenario.

[22] ORA analysts spoke with representatives from PG&E in a conference call on 10/22/14. The PGE comments were based on Work Papers not available during the drafting of these comments.

[23] ORA analysts spoke with representatives from PG&E in a conference call on 10/22/14.

[24] ORA analysts spoke with representatives from PG&E in a conference call on 10/22/14.

[25] PG&E, BPP p. 6.

C. Issues Specific to SCE's Bundled Procurement Plan

1. The Commission Should Reject SCE's Proposal to Modify the CRT

Section IV of SCE's draft 2014 BPP proposes to modify the current Commission adopted CRT.[26] In D.12-01-033, the Commission changed the CRT from a fixed one cent per kWh to an indexed amount calculated as ten percent of the IOU's system average rate.[27] SCE agrees with the indexing of the CRT values, yet requests a modification to the calculation methodology. SCE proposes that rather than basing the current CRT calculation on ten percent of the IOU system average rate, the CRT should be calculated using the ERRA portion only of the system average rate.[28] SCE's proposal is based on eliminating the non-market costs in the system average rate, which it claims is best represented by the ERRA portion of the rate covering energy market prices.

The Commission should reject SCE's proposal to lower the CRT. In the last LTPP proceeding that addressed hedging ((R.)10-05-006), SCE argued for a seven percent CRT, opposing ORA's proposed ten percent CRT. In D.12-01-033, the *Decision Approving Modified Bundled Procurement Plans*, the Commission did not adopt SCE's proposed seven percent CRT and stated:

> "Raising the CRT to 10% of each utility's system average rate should reduce both the amount and cost of hedging. While this potentially increases the risk to ratepayers of rate increases, that risk remains relatively limited."[29]

The decision was made based on a system average rate since that is what the customer sees and the amount hedging practices seek to hold stable.

SCE supports its alternative CRT calculation by providing hypothetical examples.[30] The examples are based on an assumption that the non-market costs represent half of system average rate. While the examples are hypothetical and do not represent the actual percentages of energy market prices versus non-market prices, using these examples to calculate the CRT would reduce

---

[26] SCE BPP, Section IV. A., pp. 24-28.

[27] D.12-01-033, p. 48.

[28] SCE BPP, Section IV. A., p. 28.

[29] D.12-01-033, pp. 25-26.

[30] SCE BPP, Section IV.A., p. 27.

the CRT by half, to five percent rather than the Commission mandated ten percent. Reducing the basis to which the ten percent CRT is applied reduces the CRT, resulting in increased hedging and greater ratepayer costs. Furthermore, while requesting that the system average rate be tied to the ERRA portion of the rate, SCE fails to offer data on the actual ERRA portion of rates compared to its combined system average rate. SCE does not provide historic or future non-market cost projections to inform the record of the impacts of its proposal.

SCE's rationale for lowering the CRT does not clearly establish benefits to ratepayers. For example, SCE states "[h]aving a CRT set so high that consultation is never required with the PRG diminishes the value of having a CRT at all,.."[31] and "…some adjustments to this guiding metric are necessary so that PRG consultation can occur at a more appropriate threshold."[32] SCE's concern over not sharing adequate hedging information with its PRG does not support the proposed change, since all IOUs file monthly risk reports with the Commission. The Commission mandated that the report[33] include "a portfolio risk assessment, a portfolio cost report, the time periods covered by the portfolio risk assessment, and SCE's methodologies used in developing portfolio cost distributions."[34] Those reports are available to PRG members.

SCE states that "lowering the CRT would mean proposals for incremental hedging can be discussed with SCE's PRG"[35] implying incorrectly that the current CRT precludes discussions with the PRG. It does not. Additionally, all IOUs provide quarterly "deep dive" energy procurement reviews at the PRG which always includes a section to update the PRG on hedging activities. While the CRT requires a mandatory meeting of the PRG when the TEVaR exceeds the limit, this mandatory meeting requirement is expected to occur infrequently with a well-managed hedging strategy.

In the absence of any clearly defined benefits to SCE's proposal to modify the CRT, the Commission should reject the proposal.

---

[31] SCE BPP, p. 25.

[32] SCE BPP, p. 26.

[33] D.07-12-052, p. 180.

[34] SCE BPP, Sheet 29.

[35] SCE BPP, p. 26.

2. The Commission Should Clarify the Intent of Changes to the CRT adopted in D.12-01-033

SCE's draft BPP contends "the decision is clear that the CRT is a consultation requirement and the CRT framework is not a prohibition on forward procurement."[36] In referring to the CRT, SCE further states that "Hedging to reduce such risk can and does occur below that threshold. This however leads to the inevitable question of how far below that threshold should hedging occur."[37]

In fact, D.12-01-033 expressed the Commission's intent to prevent the IOUs from hedging against minor rate increases and to reduce the amount of overall hedging the IOUs engage in on behalf of their customers:

> "DRA, SCE and PG&E fundamentally agree on a change to the method of calculating the Customer Risk Tolerance (CRT), which is used as a metric to guide the utilities in determining their appropriate level of hedging against potential electric rate increases."[38]

Decision 12-01-033 further noted:

> "We agree with DRA that our currently authorized hedging appears to have resulted in ratepayers purchasing hedging to protect against relatively minor rate increases. In short, ratepayers have been paying for too much hedging. Raising the CRT to 10% of each utility's system average rate should reduce both the amount and cost of hedging."[39]

SCE's interpretation of the Commission's ruling on the CRT issue in D.12-01-033 appears to contradict the language of the decision and would result in a lower CRT as rejected by the Commission in D.12-01-033. Therefore, ORA requests that the Commission issue clarifying language in its decision approving the IOUs' BPPs that explains the CRT limits and offers further guidance regarding its calculation.

3. The Commission should reject SCE's Hedging Proposal for Failure to Comply with Public Utilities Code Section 454.5 (b) (10)

The hedging section of SCE's draft BPP, fails to meet the requirements and guidance of Public Utilities Section Code 454.5 (b)(10), which requires that IOUs' procurement plans include

---

[36] SCE Response to ORA Data Request R.13-12-010-Phase 2-ORA-SCE-001, Question 1a.

[37] SCE BPP, p. 25.

[38] D.12-01-033, p. 22.

[39] D.12-01-033, pp. 25-26.

"[t]he electrical corporation's risk management policy, strategy, and practices, including specific measures of price stability.[40] ORA recommends that the Commission reject SCE's hedging plan unless SCE makes the modifications described below.

In D.12.01-033, the Commission required that "Utility hedging should be made simpler and less expensive."[41] Unlike the proposed BPPs of PG&E and SDG&E, SCE does not provide specific details as to how it will conduct its hedging strategy, nor how SCE has made its hedging plan simpler and less expensive. In fact, SCE's proposal to lower the CRT by applying a ten percent rate to only a portion of its system average rate can be expected to *increase* hedging activities. SCE fails to make a case that this is necessary to best meet customer needs, especially when neither PG&E nor SDG&E call for a change to the CRT.

SCE's proposed BPP does not provide adequate information for the Commission to authorize its hedging strategy and preclude after-the-fact reasonableness review. SCE does not provide hedging targets, responses to market conditions or variations on the hedging strategy in future years. Much greater detail demonstrating compliance with Public Utilities Code Section 454.5 (b) 10 and D.12.01-033.is provided in the confidential filings of the other two IOUs. [redacted] PRG meetings are a purely advisory and non-public venue for non-market participants like ORA to express their concerns with the IOUs' procurement practices and decisions. It is only through public review of the BPPs in the LTPP process that stakeholders can exert influence on the procurement plans. [redacted] For that reason, the Commission should not grant SCE unfettered authority to hedge on behalf of California ratepayers. [redacted] It also removes this issue from the wider stakeholder discussion and vetting process that is the foundation of the public LTPP

[40] Public Utilities Code Section 454.5 (b) (10).

[41] D.12-01-003, Conclusions of Law #3, p. 48.

135650959

proceeding. Instead, the Commission should require SCE to submit a modified hedging plan that would include adequate details about its hedging strategy [redacted] as well as any other changes to its hedging plan. This information should include specific details about how SCE will simplify its hedging plan and decrease ratepayers costs, and [redacted] and other strategic changes that will guide future hedging.

D. The Commission Should Defer Consideration of SCE's Proposal to Streamline Approval of Short-Term RPS Contracts pending the adoption of the IOUs' RPS Procurement Plans

ORA supports integrated resource planning and generally supports the approach outlined in SCE's request for pre-approval of short-term (less than five years) eligible renewable resource (ERR) contracts solicited through an all-source request for offers (RFO). In its 2014 Draft Bundled Procurement Plan (SCE draft BPP), SCE points out that under the current AB 57 BPP rules, short-term contracts for conventional resources and other standard products that meet the Commission's upfront standards and conditions, do not require a separate Commission decision or resolution for approval. Instead, they can be submitted through SCE's Quarterly Compliance Report (QCR) filing because these contracts are deemed per se reasonable.[42] The same rules do not apply to short-term renewable contracts; in D.04-12-048 the Commission stated that, "renewable contracts from all-source solicitations must be submitted with an application."[43] According to SCE, this extra step for approval of short-term renewable contracts puts these contracts at a competitive disadvantage in all-source solicitations for residual bundled procurement need by subjecting these contracts to "delay[s] and market uncertainty during what is often a lengthy contract approval process."[44] SCE claims that ERR contracts incorporate this approval risk into the contract price, which "typically translates into a premium above that of an approved product in SCE's AB 57 BPP".[45] This further limits SCE's ability to procure ERRs to comply with authorized need or to meet the Loading Order.

---

[42] SCE BPP, pp. 9-10, D.07-12-052, p. 171-172.

[43] D.04-12-048, p. 108.

[44] SCE BPP, p. 10.

[45] SCE BPP, p. 11.

The Commission is currently considering renewable procurement reform in a PD on the IOUs' 2014 Renewables Portfolio Standard (RPS) Procurement Plans.[46] The PD, issued on October 21, 2014, proposes that the IOUs file each RPS purchase and sale contract with a term of five years or less, through a separate Tier 1 Advice Letter for Commission approval and cost recovery. This review process will apply to all RPS purchase and sale contracts of terms of five years or less, regardless of whether the contract is procured through an all-source RFO or RPS-specific solicitation. ORA supports the October 21, 2014 PD's for simplifying approval of renewable resources and therefore, recommends that the Commission defer consideration of SCE's proposal in its draft BPP pending the adoption of the IOUs' 2014 RPS Procurement Plans.

E. Issue Specific To SDG&E's draft BPP: The Commission Should Require SDG&E to Correct Double Counting of Demand Response Programs

SDG&E's forecast of system peak demand in Table A-1 uses the CEC's 2013 IEPR load forecast.[47] While the IEPR has previously reported estimated impacts for real-time or time-of-use pricing and permanent load shifting Demand Response programs, this latest load forecast also included estimated impacts for critical peak pricing and peak time rebate programs.[48] SDG&E's assumptions for Demand Response in Table A-1 reflect estimated impacts of Demand Response programs including those already incorporated in the IEPR load forecast.[49] This causes double counting of some Demand Response program impacts. To remedy this overestimation of Demand Response impacts, SDG&E should replace its values for Demand Response with those in the Scenario Tool (version 2), as directed by the May 14, 2014 *Assigned Commission's Ruling Technical Updates to Planning Assumptions and Scenarios for use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP*.[50] The Scenario Tool reports Demand Response program impacts only for those programs that are not included in the

---

[46] R.11-05-005 Proposed Decision Conditionally Accepting 2014 Renewables Portfolio Standard Procurement Plans and Off-Year Supplement to 2013 Integrated Resource Plan at p. 64-83.

[47] SDG&E draft BPP, Appendix A, p. A-1.

[48] January 2014 CALIFORNIA ENERGY DEMAND 2014–2024 FINAL FORECAST Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency, p. 37-38. Available at http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf

[49] SDG&E October 31, 2014 Response to ORA Question.

[50] *Assigned Commission's Ruling Technical Updates to Planning Assumptions and Scenarios for use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP*, May 14, 2014, p. 6.

IEPR load forecast. For SDG&E these programs are the Base Interruptible Program, Capacity Bidding Program, Demand Bidding Program and Summer Saver for SDG&E. By using the values in the Scenario Tool, SDG&E's estimates would be consistent with Commission direction and avoid double counting of Demand Response programs.

IV. CONCLUSION

ORA respectfully recommends that the Commission:

- Develop utility reporting requirements for non-compliant transactions;
- Conduct an independent expert review of the utilities' hedging plans to enhance regulatory oversight and provide guidance to the utilities;
- Incorporate Demand Response as part of Least Cost Dispatch;
- Rely on the mandated Trajectory Scenario for PG&E instead of PG&E's Alternative Scenario;
- Reject SCE's proposal to modify the CRT;
- Clarify the changes to the CRT adopted in D.12-01-033;
- Reject SCE's hedging proposal for failure to comply with Public Utilities Code Section 454.5;
- Defer consideration of SCE's proposal to streamline approval of short-term RPS contracts until after adoption of the pending PD in the RPS Rulemaking (R.11-05-005); and
- Require SDG&E to correct double counting of DR Programs.

Respectfully submitted,

/s/ DIANA L. LEE

DIANA L. LEE
Attorney

for the Office of Ratepayer Advocates

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-4342
Facsimile: (415) 703-2262
Email: Diana.lee@cpuc.ca.gov

November 4, 2014