STATE OF CALIFORNIA EDMUND G. BROWN JR.

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

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TO PARTIES OF RECORD IN RULEMAKING 13-12-010:

This is the proposed decision of Administrative Law Judge David M. Gamson. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's October 22, 2015 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:dc3

Attachment

Decision **PROPOSED DECISION OF ALJ GAMSON** (Mailed 9/22/15)

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)

DECISION APPROVING 2014 BUNDLED PROCUREMENT PLANS

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DECISION APPROVING 2014 BUNDLED PROCUREMENT PLANS

Summary

This decision approves with modifications the plans of Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company to procure electricity for their bundled customers, consistent with Pub. Util. Code § 454.5. Per this statute, approval of these plans obviates the need for after-the-fact reasonableness review by the Commission of the resulting utility procurement decisions that are consistent with the approved plans. In addition, we provide guidance to the utilities for their future bundled procurement plans.

1. Procedural Background

The Commission, in Decision (D.) 04-12-048, D.07-12-052 and D.12-01-033, has previously reviewed and approved the long-term procurement plans of the utilities under Assembly Bill (AB) 57 (Stats. 2002, ch. 835), which enacted Pub. Util. Code § 454.5.[1] AB 57 established the method by which the utilities would resume electricity procurement, replacing the California Department of Water Resources, which had taken on that responsibility in the wake of the California Energy Crisis. Those prior Commission decisions indicate that the review and approval of utility procurement plans as required under § 454.5 is both complex and continuing to evolve, and they provide a thorough background which need not be repeated here. We anticipate that the processes utilized by the utilities and this California Public Utilities Commission (CPUC or Commission) in

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[1] Unless otherwise stated, all statutory references are to the Public Utilities Code.

developing, reviewing, and approving procurement plans will continue to evolve in future proceedings.

The Order Instituting Rulemaking (OIR) that opened this proceeding established three separate tracks.

1) Identify CPUC-jurisdictional needs for new resources to meet local or system resource adequacy (RA), operational flexibility, or other requirements and to consider authorization of IOU[2] procurement to meet that need. This includes issues related to long-term renewable planning and need for replacement generation infrastructure to eliminate reliance on power plants using "once-through" cooling.
2) Update, and review individual IOU bundled procurement plans (BPPs) consistent with § 454.5.
3) Develop or refine procurement rules that were not resolved in Rulemaking (R.) 12-03-014, and consider other emerging procurement topics not expressly covered in other rulemakings.

The bundled procurement track addressed in this decision was described in R.10-05-006 (the last Rulemaking where bundled plans were considered) at 2 as follows:

> In one track, we shall consider adoption of "bundled" procurement plans pursuant to AB 57 (codified as Pub. Util. Code § 454.5) for the three major electric IOUs to authorize their procurement needs for their bundled customers.

R.10-05-006 at footnote 1 also provided the following definition:

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[2] The OIR used the term "IOU" as initials for "Investor-Owned Utilities." Elsewhere in this decision, we use the term "utilities" instead to specifically reference SCE, SDG&E and PG&E.

> We define "bundled" as pertaining to an IOU's load and resources in its role as a Load Serving Entity. To distinguish filings related to bundled AB 57 obligations from separate filings related to system reliability needs, we will refer to these as "procurement plans."

Similarly, in the OIR for this proceeding, the Commission stated:

> This proceeding will consider individual IOU procurement plans pursuant to § 454.5. Each IOU shall file proposed updates to its individual bundled plan consistent with guidance to be provided in the Scoping Memo and any related rulings or decisions.
>
> We anticipate that the IOUs shall file their updated bundled plans in 2014. We expect these IOU bundled filings to reflect changes subsequent to D.12-01-033. Evidentiary hearings are anticipated for this portion of the proceeding.

The May 6, 2014 Scoping Memo generally described the scope of this track of the proceeding:

> The Long-Term Procurement Plan (LTPP) proceedings generally operate on a two-year cycle with the IOUs responsible for submitting procurement plans that project their need, and their action plan for meeting that need, over a ten-year horizon. Pursuant to Assembly Bill (AB) 57, codified as Section 454.5, by approving procurement plans, the Commission establishes "up-front standards" for the IOUs' procurement activities and cost recovery. This obviates the need for after-the-fact reasonableness review by the Commission of the resulting utility procurement decisions that are consistent with the approved plans.
>
> There were no updated bundled procurement plans (BPPs) filed in R.12-03-014. For this proceeding, we direct the IOUs' filing of bundled LTPPs to be based on the Trajectory Scenario of the Assumptions, Scenarios and Renewable Portfolio Standard (RPS) adopted for use in the 2014 LTPP by the February 27, 2014 ruling. Our intent is to ensure that the IOUs' plans can be more easily compared to each other and to maintain consistency, where appropriate, with Commission policy in other procurement-related proceedings. Parties may provide analysis on alternative

> assumptions in addition to those contained in the adopted Trajectory scenario.

The Scoping Memo continued:

> For Phase 2, the following issues related to BPPs are within the scope of the proceeding:
>
> 1. Maximum and minimum limits on IOU 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.

Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Pacific Gas and Electric Company (PG&E) filed their BPPs on October 3, 2014. Comments on the utilities' BPPs were filed on November 4, 2014 by Alliance for Retail Energy Markets (AReM), Cogeneration Association of California (CAC) and Energy Producers and Users Coalition (EPUC) (jointly), Center for Energy Efficiency and Renewable Technologies (CEERT), Marin Clean Energy (MCE), Office of Ratepayers Advocates (ORA), PG&E, L. Jan Reid (Reid), Sierra Club and California Environmental Justice Alliance (CEJA) (jointly), and World Business Academy (WBA). Reply comments were filed on November 20, 2014 by MCE, ORA, PG&E, Reid, SCE, SDG&E, and Sierra Club/CEJA.

No party requested evidentiary hearings, and none were held. The record of this decision is the filed comments.

On November 4, 2014, ORA filed a "Motion for Leave to File Confidential Version of ORA's Comments on the Proposed Bundled Procurement Plan of PG&E, SCE and SDG&E Under Seal." That day, Reid filed a "Motion for leave to file confidential materials under seal; confidential materials attached and filed under seal, namely, confidential comments of L. Jan Reid on PG&E's Bundled Procurement Plan." On November 20, 2014, ORA filed a "Motion for leave to file confidential material under seal" regarding its reply comments. That day, PG&E filed a "Motion to File Under Seal Confidential Version of Reply Comments on Proposed Bundled Procurement Plan." No party opposed any of these Motions. These Motions are granted.

2. Context of Proceeding

This decision renews and updates the utilities' procurement authority on behalf of their bundled customers, consistent with the policies of this Commission and the State of California. The changes to the utilities' procurement authority that are made in this decision are largely technical revisions based on our recent experience, adjustments to reflect changed circumstances, and clarifications based on past experience and issues raised by the parties.

Because Pub. Util. Code § 454.5 provides that approval of the BPPs (as appropriately modified by the Commission) obviates the need for after-the-fact reasonableness review by the Commission of the resulting utility procurement decisions that are consistent with the approved plans, we must closely scrutinize the plans to ensure upfront that they are reasonable, consistent with statute, appropriately protect ratepayers and are in the public interest.

At the same time, because this decision largely follows existing policies rather than make new policies, the scope of this decision is relatively narrow. This decision excludes consideration of much procurement done by the utilities. This decision is not intended to result in any new generation facilities being constructed, and it continues to implement the Commission's loading order and Energy Action Plan (EAP). Other utility procurement activities are considered in other parts of this proceeding (e.g., local, system and flexible procurement for reliability purposes) or in other proceedings (e.g., the RPS Rulemaking (R.11-05-005)).

As stated in D.12-01-033 at 3:

> Bundled Track II procurement is focused on the short-to-medium term operational needs of the utilities, and should not result in construction of new generation facilities. As a practical matter, in order to meet their short and medium term needs, such as replacing expiring contracts, the utilities will need to be contracting with existing facilities, rather than with proposed new facilities. Accordingly, approval of the utilities' Bundled Track II procurement plans will not indirectly lock in a longer-term resource commitment by causing new generation to be built.

We reiterate this guidance for the BPPs filed in 2014.

3. Utility Proposals

3.1. Eligible Renewable Resources (ERRs) Contracts Less than Five Years (All)

SCE seeks authority to enter into transactions with ERRs for terms of less than five years consistent with the other applicable upfront and achievable standards of its BPP in furtherance of the Loading Order. Currently, SCE has the authority to procure renewable resources through an all-source Request for Offers (RFO) as standard energy and capacity. However, SCE notes that renewable resources are not an authorized product in SCE's BPP and thus are not eligible for submission through the BPP process. SCE seeks authority to conduct transactions of less than five years in duration through the BPP with ERRs that are able to compete head-to-head with other preferred and conventional resources and meet all of SCE's other upfront standards and criteria. SCE asks that the Commission allow SCE to enter into contracts with ERRs under its BPP with the same review process as other authorized BPP products. That is, the renewable transactions will be subject to all of the same AB 57 rules which, if followed and approved in SCE's Quarterly Compliance Report (QCR), result in transactions that are *per se* eligible for cost recovery with no further application or advice letter approval process.[3] PG&E and SDG&E make the same request as SCE for authority to enter into transaction with ERRs for terms of less than five years.

3.1.1. Parties' Comments

CEERT and WBA support SCE's request to add a new renewable product to its preapproved BPP electric transactions. CEERT asks that a similar product also be added to PG&E and SDG&E's BPPs. ORA recommends deferring consideration of SCE's proposal to streamline approval of short-term RPS contracts until after adoption of the pending decision in the RPS Proceeding, R.11-05-005.[4] Reid supports PG&E's request to sign renewable contracts of up to five years with suppliers that submitted winning bids in a PG&E all source RFO, subject to two conditions, and also to require PG&E to file an expedited application or Tier 3 Advice Letter for approval of these contracts.

3.1.2. Discussion

SCE requested similar authority in its 2010 BPP, but the Commission found that this was more appropriately addressed in the RPS proceeding. Moreover, the Commission recently addressed the approval of ERRs contracts with terms of less than five years in D.14-11-042, Ordering Paragraph 27, which authorized the utilities to submit these transactions through a Tier 1 Advice Letter process.

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[3] SCE 2014 Draft BPP at 8-12.

[4] This decision was issued as D.14-11-042 after comments were filed in this proceeding.

Therefore, this matter has already been decided and we need not consider it further here. Accordingly, we deny SCE, PG&E and SDG&E's request.

3.2. Brokered Transactions for Greenhouse Gas (GHG) Compliance Products (All)

SCE seeks authority to use brokered transactions for GHG compliance products, as the market for such has evolved. SCE proposes that it be allowed to use brokers to buy and sell GHG offsets and allowances.[5] SCE seeks authorization to use any of the brokers on the "List of Authorized Brokers and Exchanges" shown in Appendix D of its BPP to procure GHG products. PG&E and SDG&E request that they also be allowed to use brokers.

3.2.1. Discussion

Under the procurement rules developed in D.12-04-046, the electric utilities currently cannot use a broker unless the broker participates in a utility's competitive solicitation for compliance instruments. When D.12-04-046 was approved in April 2014, the California Air Resources Board (CARB) had not yet held its first GHG allowance auction, so there was no evidence of a liquid and transparent GHG market. The decision noted that "there will be other possible sources of allowances and offsets, particularly as the market develops further. These include exchanges, brokers, and bilateral transactions. As the market develops, there may be a liquid and transparent market in greenhouse gas compliance products…"[6]

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5 SCE 2014 Draft BPP at 29.

6 D.12-04-046 at 53.

The market has since developed further, as CARB has now held a successful GHG allowance auction. Further, in D.14-12-040 the Commission authorized the natural gas utilities to procure GHG compliance instruments through brokers or exchanges that have been pre-approved by the Commission through a Tier 2 Advice Letter filing.

Accordingly, we will allow PG&E, SCE, and SDG&E to use brokers to procure GHG allowances and offsets. As a result, SDG&E and PG&E will now have more consistent GHG procurement policies across their electric and natural gas portfolios. The utilities will report the brokered transactions in their Quarterly Compliance Reports and provide a strong showing in these reports.

3.3. Include GHG Limits in Rates and Limits Advice Letter (All)

SCE proposes a streamlined process for updating all of its rates and limits through one advice letter filing in years where it does not submit a BPP. Currently, SCE provides an update to its electricity and natural gas position limits and ratable rates in the form of a Tier 1 Advice Letter during years in which SCE does not file an updated conformed BPP. In addition, and in accordance with D.12-04-046, SCE is required to file an update to its GHG transaction rates and procurement limits in the form of a separate Tier 2 Advice Letter. Both Advice Letters are submitted on or before October 31 each year.

SCE believes that the GHG cap-and-trade market now resembles a well-established commodity market and thus maintaining a limit update consistent with other energy products would improve the GHG limit process and streamline the filing process. As such, SCE proposes that all updates to SCE's procurement limits and ratable rates, including its GHG transaction rate and limits, be filed through a single Tier 1 Advice Letter filing during years in which

SCE does not file an updated, conformed BPP, or more often if necessary. PG&E and SDG&E also request the same streamlined process.

3.3.1. Discussion

We agree that the Advice Letter process for procurement limits and ratable rates can be streamlined. We allow the utilities to each submit one Tier 1 Advice Letter for all procurement limits, including GHG procurement limits.

3.4. Tier 2 Advice Letter for BPP Filing (All)

In the 2010 LTPP decision, D.12-01-033 Ordering Paragraph 21, the Commission ordered the utilities to submit the conformed filings through a Tier 3 Advice Letter. SCE seeks a streamlined process for the required conformed advice letter filing once SCE's BPP is approved in this proceeding. SCE recommends that the Commission adopt a Tier 2 Advice Letter process for approval of the utilities' conformed BPPs. PG&E and SDG&E request the same streamlined process.

3.4.1. Discussion

The review of the utilities' conformed BPPs can reasonably be considered to be ministerial as it would not result in changes to existing policies. We adopt SCE's proposal to allow the utilities to file a Tier 2 Advice Letter for approval of their conformed BPPs.

3.5. Procurement Review Group (PRG) Notification Regarding Convergence Bidding, Investigations, and Suspensions (All)

PG&E's BPP states that PG&E intends to monitor the net profit and losses associated with convergence bids and, should the 365-day rolling net-loss exceed or look to exceed $20 million, PG&E will cease implementation of all convergence bidding strategies and confer with the PRG pursuant to D.10-12-034. D.10-12-034 authorized the utilities to participate in convergence bidding in markets operated by the California Independent System Operator (CAISO), subject to a uniform set of three authorized bidding strategies for all utilities. The Commission also imposed an annual stop loss limit of $20 million for PG&E, $20 million for SCE, and $5 million for SDG&E.

3.5.1. Parties' Comments

Reid would add to PG&E's recommendation three more circumstances when PG&E should confer with the PRG:

1. Notice from the CAISO or its Department of Market Monitoring that PG&E or its scheduling coordinator is subject of an investigation pursuant to the CAISO Tariff.
2. Notice from the CAISO that the conduct of PG&E or its scheduling coordinator's conduct has been referred to the Federal Energy Regulatory Commission by CAISO pursuant to the CAISO Tariff.
3. Notice from the CAISO that PG&E or its scheduling coordinator's convergence bidding trading has been suspended or limited by the CAISO.

Reid suggests that PG&E should notify the PRG within two business days should any of these conditions occur.

ORA notes that the three utilities are required to provide written notice to the Commission's Executive Director, the Director of the Energy Division, and the Commission's General Counsel within one business day of being notified if any of the above conditions occur. Thus, it should not pose any burden for the Commission to require that all three utilities inform the PRG within two business days in the event of these conditions.

PG&E responds that it accepts Reid's proposed conditions, but would prefer five (5) business days to provide notice to the PRG so it can review the CAISO notice and provide the PRG with adequate background.

3.5.2. Discussion

As the PRG may require additional background than would be needed by the Commission's Executive Director, the Director of the Energy Division, and the General Counsel, it is reasonable that each of the utilities should be required to inform their respective PRGs in these circumstances in a short period of time. We will require the utilities to notify the PRG within three (3) business days when their 365-day rolling average net-loss exceeds their respective limits and under the three additional circumstances discussed above.

3.6. Alternative Scenario for Bundled Electric Forecast (PG&E)

The utilities were instructed in the May 6, 2014 Scoping Memo to file BPPs based on the trajectory scenario of the Assumptions, Scenarios, and RPS adopted for use in the February 27, 2014 ruling. The goal of requiring the utilities to base their BPPs on the trajectory scenario was so that the utilities' plans could be easily compared to each other and to maintain consistency with other procurement-related proceedings. The utilities were permitted to provide an additional analysis based on alternative assumptions.

PG&E was the only utility to submit an analysis based on alternative assumptions to the trajectory scenario,[7] which included modified assumptions for departing load and distributed generation. In its alternative scenario, PG&E

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[7] PG&E refers to the Commission's trajectory scenario as the "mandated" scenario.

estimated a significant reduction in its forecasted electricity demand from three sources: growth in existing and new Community Choice Aggregators (CCAs), growth in behind-the-meter distributed generation, and continuing demand for Direct Access (DA). PG&E based its CCA load departure estimates on its load growth expectations for the two active CCAs, MCE and Sonoma Clean Power, as well as on 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. PG&E based its distributed generation trends on recent growth in the photovoltaic market, which it believes will continue to increase, albeit at a slower rate after 2018. PG&E justifies using these assumptions in its alternative scenario because these factors were not accounted for in the Commission's trajectory scenario.

3.6.1. Parties' Comments

MCE finds that PG&E's alternative scenario far more accurately estimates departing load due to existing, pending and invested CCA efforts over the next 10 years. The trajectory scenario forecasts a highly unrealistic downward trend of departing load due to CCA programs over the next 10 years and fails to account for significant developments in demand response and distributed generation resources. Thus, MCE endorses the alternative scenario as "the more reasonable projection." MCE would go farther, and require PG&E to consider any community that has made a "significant financial commitment" toward the pursuit of CCA service or who are adjacent to an existing CCA as likely to leave PG&E's bundled procurement. WBA also agrees that the trajectory scenario underestimates the amount of load controlled by the CCAs, but notes that PG&E could still provide power to the CCAs if it relied more on clean energy. WBA further notes that PG&E is correct in its estimate of increased distributed generation, but asserts that hydrogen fuel cells would remedy the problems caused by increased solar distributed generation without sufficient increased storage.

AReM also agrees with PG&E that the alternative scenario may be appropriate. AReM can think of no rationale that supports the trajectory scenario assumption that DA load will decline over time. The DA cap has been full since 2010, and the space was vastly oversubscribed every time new space opened up.

ORA finds PG&E's alterative scenario to be too speculative, and recommends that it should not be used due to the considerable uncertainty. MCE contends that ORA's recommendation is lacking in factual support. MCE notes that PG&E has provided facts in support of its alternative scenario, and ORA's recommendation would run counter to the policy that utilities' BPPs should reflect reasonable and appropriate levels of departing load. Further, MCE asserts that PG&E's assumptions are not too speculative or uncertain.

PG&E believes that MCE's additional departing CCA load is either too speculative or not significant to its calculations. PG&E notes that ORA failed to provide any reasoned basis for rejecting its alternative scenario. PG&E believes its alternative scenario presents a more accurate and realistic forecast and thus should be adopted by the Commission.

3.6.2. Discussion

The increase in distributed generation and consistent level of DA in PG&E's alternate scenario are not significant for planning purposes and do not necessitate a change from the trajectory scenario. However, PG&E's calculation of departing CCA load appears to be more reasonable than the trajectory scenario. Incorporating a more realistic estimate of departing CCA load in the load forecast should result in a more realistic projection of future energy procurement for

PG&E. Therefore, PG&E's alternative scenario revisions to reflect departing load due to CCAs are adopted.

3.7. Scheduling, Bidding and Response to Operating Orders in the CAISO Markets (PG&E)

PG&E describes the protocols it has been using when CAISO declares a system emergency, congestion, or over-generation in Appendix L of its BPP. These protocols do not amend or modify the responsibilities or terms and conditions of existing agreements between PG&E and its contracted resources. PG&E includes this section because it believes that, although currently rare and expected to continue to be rare, these three situations will occur more frequently in the future due to the increasing amounts of intermittent, inflexible renewable generation on the CAISO grid.

3.7.1. Parties' Comments

WBA disagrees with PG&E's concern that increasing renewable generation will increase system emergencies, congestion, and over-generation. WBA believes that in a properly designed microgrid system, intermittency would be resolved at the substation level using load shifting and various storage technologies that will be installed on the utilities' distribution systems.

PG&E opposes this proposal because the CAISO currently issues operating orders related to system emergencies, congestion, and over-generation and will likely do so for the foreseeable future. PG&E states that this section of its BPP sets forth PG&E's protocol in response to the CAISO's operating orders.

3.7.2. Discussion

WBA's proposal is beyond the scope of this proceeding. PG&E's Appendix L describing existing protocols is otherwise non-controversial and will be adopted.

3.8. Nuclear Fuel Procurement Plan (PG&E)

The Nuclear Fuel Procurement Plan sets forth the process by which PG&E procures nuclear fuel for the Diablo Canyon Power Plant, which uses nuclear fission as its heat source. This plan provides PG&E with contracting authority for uranium, conversion and enrichment services, and inventory management procurement strategies to ensure that Diablo Canyon Power Plant reload requirements are adequately met in the future and to mitigate long term risks associated with security of supply. The Nuclear Fuel Plan runs through 2024 and is designed to supply both units at the Diablo Canyon Power Plant through the end of their operating licenses, and not beyond their current licenses.

PG&E notes that there have been substantial changes to the worldwide market in nuclear fuel since the Fukushima Daiichi incident. PG&E proposes some changes to their nuclear fuel procurement, including approving fuel contracts that expire at the same time as the operating licenses, fuel targets, risk management improvements, and for other reasons which include confidential material.

3.8.1. Parties' Comments

WBA advocates closing the Diablo Canyon Power Plant and developing more microgrids within PG&E's service area. PG&E contends the potential closure of this plant is an issue beyond the scope of this proceeding.

3.8.2. Discussion

We agree that decommissioning Diablo Canyon Nuclear Power station is beyond the scope of this proceeding. PG&E's Nuclear Fuel Plan is consistent with our direction not to exceed the license period of the plant.[8]

PG&E also requested an expedited Advice Letter process for "unseen market opportunities." PG&E has not presented any new information to depart from the ruling in D.12-01-033, which states in relevant part:

> PG&E requests that it be allowed to seek authority for transactions outside of those pre-approved here by means of an "expedited" Advice Letter process, but does not specify what that means. Rather than create a new type of Advice Letter, PG&E may file under the standard Advice Letter process pursuant to General Order 96-B, and may request an expedited review if necessary.[9]

We reaffirm that holding here.

PG&E's proposed changes regarding risk management improvements, and certain confidential matters, should be adopted to the extent they do not conflict with the Commission's prior decision in D.12-01-033, Ordering Paragraph 12, which held that "Any contract that seeks to impose additional liability for nuclear accidents on Pacific Gas and Electric Company and its ratepayers must be approved by an application, not an Advice Letter."

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[8] D.12-01-033 at 35-36.

[9] D.12-01-033 at 36.

3.9. GHG Financial Exposure Purchase Limit (PG&E)

PG&E adds a financial exposure purchase limit calculation (Appendix C), which was not included in its 2010 BPP. The financial exposure purchase limit formula was developed in D.12-04-046 and allows the electric utilities to hedge their financial exposure to GHG costs that will be embedded in the price of energy it procures. No party provided comments on this proposal.

3.9.1. Discussion

We approve PG&E's inclusion of a GHG financial exposure purchase limit, calculated in accordance with the formula established in D.12-04-046.

3.10. Hedging Plan Changes (PG&E)

PG&E proposes four changes in its hedging plan in the 2014 BPP. The following discussion relies principally on confidential material redacted from PG&E's public BPP filing, as well as redacted material in the BPP and in comments. We have reviewed all of the public and redacted material in considering these matters.

3.10.1. Changing the Hedging Plan Tenor

In the context of the Hedging Plan, tenor means the length of the delivery period to be hedged. On p. 29, PG&E's 2014 BPP proposes changing the length of the Hedging Plan tenor (the proposed change is confidential), updated once annually. PG&E explains that the proposed tenor change would allow its hedging to more closely align with products actively traded in the market.

3.10.1.1. Parties' Comments

Reid opposes this change, contending that the current tenor is justified and ratepayers are not harmed by the current system. ORA recommends that the Commission accept the changes proposed by PG&E on hedging, as they are reasonable and respond to the Commission's direction in D.12-01-033 which required utilities' BPPs to be made simpler and less expensive. ORA contends that PG&E's proposal simplifies its hedging plan with the potential to reduce ratepayer costs.

PG&E responds to Reid that neither PRG review nor the Consumer Risk Tolerance would be affected by its proposed change. PG&E argues that Reid ignores its justification for the change, and that the change should be approved.

3.10.1.2. Discussion

PG&E's proposal appears to achieve current hedging results using a simpler and less expensive method, thus we will allow this change.

3.10.2. Hedging Changes

PG&E describes certain proposed hedging changes in redacted language on pp. 30-31 of its BPP.

3.10.2.1. Parties' Comments

Reid opposes PG&E's proposed change (his specific concerns are included in confidential material). Reid asserts that a proposed redefinition may not benefit all customers.

SDG&E notes that Reid's position would hedge for DA and CCA customers in addition to bundled customers. The DA and CCA customers are likely already hedged by the third-party provider; thus hedging beyond the bundled customers is over-hedging, harmful to the public interest, and should be rejected.

ORA states that it is not clear that any inequitable costs would fall on a subset of ratepayers. Hedging, ORA maintains, covers volatility in the entire portfolio and equally protects the rates of all customers, and therefore this change should be permitted.

PG&E argues that Reid has confused PG&E's electricity position (a portfolio measure) with RA (a capacity position with locational attributes). PG&E provides a confidential explanation of its position.

3.10.2.2. Discussion

We have reviewed PG&E's proposal and parties' comments, including confidential material. We find that PG&E's proposal to make certain hedging changes as referenced on pp. 30-31 of its BPP is reasonable and should be permitted.

3.10.3. Financial Swaps

PG&E discusses certain proposed changes regarding financial swaps in redacted language on pp. 32-33 of its BPP.

3.10.3.1. Parties' Comments

Reid opposes this change in his redacted comments. ORA finds Reid's arguments unconvincing. ORA analyzes PG&E's proposal in redacted comments and concludes that the Commission should adopt PG&E's simplification of this process. PG&E responded to Reid in redacted comments.

3.10.3.2. Discussion

PG&E's proposal regarding financial swaps is reasonable because it is more transparent for the Commission and the PRG, and thus is permitted.

3.10.4. Changing the Calculation of the Minimum Price Factor

PG&E's 2014 BPP makes a second change regarding the financial swap limit in redacted language on pp. 32-33 of its BPP.

3.10.4.1. Parties' Comments

Reid opposes PG&E's proposed change as less accurate than the current method. ORA supports PG&E's proposed change as a reasonable change.

3.10.4.2. Discussion

In reviewing PG&E's proposal, we find no clear reason why PG&E's proposal would be problematic or unreasonable. PG&E has provided a reasonable justification for its proposed modification and we will permit this change.

3.11. Procurement for Operational Flexibility (PG&E)

To manage aspects of its portfolio other than financial risks -- aspects such as operational flexibility -- PG&E indicates that it will procure various electric products. PG&E contends these products may affect the physical positions and financial positions of the electric portfolio.[10]

3.11.1. Parties' Comments

Reid objects to the assertion by PG&E that it can procure electricity for operational flexibility purposes without explicit Commission permission. Otherwise, Reid contends that PG&E may procure unnecessary operational flexibility products to the detriment of its ratepayers.

PG&E responds that Reid misunderstood its statement, and it was only restating a provision of the 2010 BPP, on Sheet 110. In sum, PG&E agrees with Reid that procurement of new resources to address operational flexibility needs (i.e., non-financial goals) for the CAISO system is being considered in Tracks 1A and 1B. However, PG&E maintains that procurement from existing resources to address operational flexibility needs is appropriately addressed in the 2014 BPP.

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[10] PG&E BPP, App. E at 104.

3.11.2. Discussion

PG&E, and all affected utilities, are able to procure existing flexible products pursuant to Commission orders. We read this section of PG&E's BPP to be limited to already authorized procurement.

3.12. PRG Notification and Review (PG&E)

PG&E's BPP proposes that PG&E should be permitted to execute agreements of greater than three months if executed according to a PRG-reviewed strategy.

3.12.1. Parties' Comments

Reid opposes this change and recommends that PRG review of each transaction greater than three months in duration is required prior to execution of the transaction. PG&E and SDG&E disagree with Reid, noting that such a restriction would prevent trade in products that have price volatility or have a short window in which to execute the transaction. Further, SDG&E asserts there is no harm in allowing trades based on pre-approved strategies, and requiring the PRGs to re-approve trades made pursuant to pre-approved strategies would be a waste of the PRG's time.

3.12.2. Discussion

In D.03-12-062, Conclusion of Law 12 stated: "For transactions of greater than 90 days, the utilities should consult with the PRG." Later, D.04-12-048, Ordering Paragraph 15 stated:

> We grant PG&E's Petition to Modify D.03-12-062, and clarify that D.03-12-062 authorized IOUs to conduct procurement using negotiated bilateral agreements for transactions of up to three calendar months, or one quarter, forward; and that utilities will consult with their PRGs for transactions with delivery periods of greater than three calendar months, or one quarter.

We have already determined that it is appropriate to require that the utilities consult with their PRG for all transactions over three months, not just the pre-approved procurement strategy. While it is possible that PG&E could lose some time-sensitive opportunities due to required PRG consultation, this theoretical concern is outweighed by the general long-standing benefit of PRG consultation. Therefore, we deny PG&E's modification to execute transactions over three months without PRG review.

3.13. Options and Swaps Balance (PG&E)

PG&E proposes to change the way it balances options and swaps, basing the new balance on the Energy Resources Recovery Account (ERRA) curve forecasts.[11]

3.13.1. Parties' Comments

Reid opposes this change and asserts that PG&E should determine the percentage of options and swaps based on their volatility and cross correlation of these two products, not on the accuracy of the ERRA forecast. Further, Reid notes that PG&E does not claim that this change would benefits ratepayers.

SDG&E supports PG&E's proposed change and contends that Reid provided no meaningful analysis. SDG&E also notes that the Commission rejected Reid's comments on this matter in D.07-12-052.

ORA also casts doubt on Reid's assertion that the existing minimum variance hedge ratio is superior to the new methodology proposed by PG&E. ORA further notes that Reid's premise is only theoretical. ORA cites the

[11] PG&E BPP, Appendix E: Electric Portfolio Hedging Plan at 110-111.

Commission's previous rejection of regulating ratios of swaps to options in D.07-12-052.

In response, PG&E suggests that Reid's proposal comes from an unidentified textbook and that PG&E's Hedging Plan of three commodities (electric, gas, and GHG) is considerably more complex than the examples in the textbooks.

3.13.2. Discussion

Reid's theoretical concerns are not sufficiently explained or on point. PG&E's proposal is well-explained in the BPP and is reasonable.

3.14. Congestion Revenue Rights (CRRs) Trading Changes (PG&E)

CRRs are financial instruments issued by the CAISO and made available through the CRR allocation, CRR auction, and Secondary Registration System. CRRs enable CRR holders to manage variability in congestion costs based on locational marginal pricing. CRRs are acquired primarily, although not solely, for the purpose of offsetting integrated forward market congestion costs that occur in the day-ahead market.

Currently, the trading of CRRs by utilities must be approved in advance. PG&E proposes that it would no longer need pre-approval to trade CRRs, but would notify the PRG five (5) business days after transactions, and the entire CRR strategy would be reviewed once a year by the PRG.[12]

[12] PG&E LTPP cover letter at 44, and Appendix M at 201, line 9.

3.14.1. Parties' Comments

Reid believes that the Commission should require PG&E to discuss its CRR nomination process with the PRG in advance, even if planned trades may be different from actual CRR trades.

PG&E responds that the 2014 BPP does require consultation with the PRG prior to the start of the CRR process, and that the consultation would include the procurement approach and strategy.

3.14.2. Discussion

With PG&E's clarifications, there appears to be no dispute. This change is permitted.

3.15. Removing the Price of GHGs from the Implied Market Heat Rate (PG&E)

Utilities are restricted in the amounts they can procure for the upcoming year by electric procurement limits, and there are ratable position limits on forward procurement quantities for future years. (e.g., the nearer in the future the procurement is for, the greater percentage of procurement would be authorized.) Procurement is permitted at a higher rate, twice the ratable rate, subject to the electricity procurement limits, if the 12-month forward on-peak implied market heat rate at the time of execution is less than the two-standard deviation historical high value, measured in one million British Thermal Unit/megawatt hour. PG&E notes that the calculations used to determine this historical high value of the implied market heat rate include values before and after December 2012, when GHG costs enter the market. PG&E proposes to remove these embedded GHG costs when calculating the historical high value.

3.15.1. Parties' Comments

Reid opposes this change, since PG&E provides no evidence that GHG costs are fully embedded in the forward price of electricity. He notes that: (1) not all bidders into the market have GHG costs, and so stripping GHG costs from their products would undervalue them; (2) market conditions have changed since 2012, and thus cannot be modeled using simply post-2012 cost, less the cost of GHG; and (3) PG&E assumes that the weighted average in the GHG market is the same as the weighted average in the overall market, which is unreasonable and likely incorrect. Mr. Reid concludes that the Commission should reject PG&E's proposal concerning the modification of forward prices for procurement purposes.

PG&E responds that the 2014 BPP methodology was approved in the 2010 LTPP. PG&E is not asking for any change to its methodology for calculating and operationalizing the Implied Market Heat Rate metric. Second, this parameter does not directly impact the cost of capacity. It merely determines how fast PG&E can close its capacity open position, not the price of acquisition. The purpose of the calculation and the rule is to allow accelerated procurement when prices are favorable. Therefore, it is unclear that accelerated procurement will result in higher rates for ratepayers.

3.15.2. Discussion

It is correct that the cost of all energy in the CAISO market does not include an embedded GHG cost. However, the price used in the CAISO market calculation is the marginal cost of energy, not the average cost. The marginal cost of power in California is typically set by natural gas power plants, which includes the cost of GHGs for these plants. The implied market heat rate (the price of electric power divided by the price of natural gas) would be elevated because the cost of the GHG permit would be included in the price of electric power, but that cost is not included in the price of natural gas. This increase in the implied market heat rate would raise the bar for PG&E to qualify for an accelerated rate of procurement, thus preventing PG&E from acquiring some additional future capacity when the cost is comparatively low. Removing the value of the GHGs from the implied market heat rate would restore the prior metric put in place by the Commission in our earlier decisions and remove a disincentive for cost-effective procurement. Thus we will permit such a change, with the condition that PG&E provide a report showing the effect of the change on the first applicable year by December 31, 2016.

3.16. Updated and Expanded Brokerages and Exchanges List (PG&E)

PG&E provides an updated and expanded list of brokerages and exchanges list in the 2014 BPP in Appendix J.

3.16.1. Parties' Comments

Reid opposes the additional brokerages since PG&E did not explain why it needs access to one brokerage, ICE Clear Europe.

PG&E responds that certain financial products used by PG&E may only be cleared through ICE Clear Europe, and the Commission has, in the past, authorized PG&E to transact on ICE in previous BPPs, including the PG&E 2006 BPP (where the clearinghouse was known as the London Clearinghouse) and the PG&E 2010 BPP (where the clearinghouse was known as the ICE Clear Europe). Thus, PG&E maintains, the Commission's authorization for PG&E to transact on ICE and ICE Clear Europe should remain in place.

3.16.2. Discussion

PG&E was previously approved to access brokerages including ICE, and Reid has not adequately explained why this approval should now be changed.

PG&E will be permitted to continue trading on the brokerages listed in Appendix J.

3.17. Proposed Third Phase of this Proceeding to Discuss Safety (PG&E)

PG&E notes that one issue that was not identified for this phase of the 2014 LTPP proceeding was safety.[13] PG&E recommends the Commission establish an additional phase of the 2014 LTPP proceeding that is solely focused on how safety should be incorporated into the utility procurement process, including how safety is used in the offer evaluation process and the assignment of responsibilities between generators and the utilities for the safe operation of facilities.

3.17.1. Parties' Comments

WBA advocates, as a matter of safety, to transition as soon as possible to fuel cell technology, using renewable hydrogen as a feedstock. Also, WBA argues that the Commission should require the utilities to adopt as part of their BPPs the strategic location of battery and electrolysis facilities at the substation level. Such technologies can directly store, or convert all excess renewable energy generation into hydrogen, for short or long-term future use.

3.17.2. Discussion

Safety is considered in all the decisions of the Commission and remains its highest priority. Safety is considered at each step of the Commission's actions and processes. Safety should be incorporated into the utility procurement process, including the offer evaluation process and the assignment of responsibilities between generators and the utilities for the safe operation of facilities.

Since safety is considered in each step of reviewing procurement plans by the utilities, we do not see the need for an additional phase of the proceeding focusing solely on safety. Nor should the massive overhaul of the California economy proposed by WBA be adopted solely on the basis of safety. Any project bid into an RFO by any utility (e.g., fuel cells, solar, or other method of production) will include consideration of the basis of safety, as well as on the cost and effect on the environment.

3.18. Preferred Resource Descriptions and Outreach to Bidders (SCE)

SCE requests approval of certain clarifications to its existing authorized preferred resources products and processes. To further enable SCE to procure energy efficiency, demand response, and distributed generation resources to meet SCE's residual bundled procurement need within the context of its BPP, SCE added these products to the list of authorized products in Appendix A of SCE's BPP. SCE believes that through SCE's Local Capacity Requirement RFO process, it has developed improvements to enable preferred resources to participate in its competitive procurement process. SCE intends to adapt these approaches, to the extent practical and applicable, to procure preferred resources in its all-source RFOs for residual bundled procurement. However, SCE does not propose any changes to the "least-cost/best-fit" methodology that is used to evaluate offers in its bilateral or solicitation process. No party commented on this proposal.

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[13] PG&E cover letter at 13.

3.18.1. Discussion

We recognize SCE's intention and effort to follow the loading order and procure preferred resources in their bundled procurement plan. SCE should be allowed to solicit preferred resources in its all source RFO to meet the residual net short; however, we do not authorize the pre-approval of these products in the BPPs. If SCE were to procure the preferred resources products, SCE needs to seek approval for these contracts in the existing approval processes already established by the Commission for the respective programs.

3.19. Consumer Risk Tolerance Methodology Adjustment (SCE)

The Customer Risk Tolerance (CRT) is a metric used to guide the utilities in determining their appropriate level of hedging against potential electric rate increases.

D.12-01-033 ordered that the CRT be derived as follows:

1. A base load forecast scenario in kilowatt-hour (kWh) for the applicable rolling forward 12-month period is prepared.
2. The total 12-month load forecast is multiplied by the then-current CRT rate, which is expressed in cents/kWh. This represents the CRT that is compared to the prompt 12-month To Expiration Value at Risk (TEVaR) calculation.
3. The CRT rate will be 10% of the utility's system average rate.

SCE proposes changing the CRT calculation methodology used for determining the consultation requirement with SCE's PRG regarding hedging activity. SCE proposes to amend the derivation of the CRT rate from 10% of the system average rate to 10% of the ERRA portion of SCE's system average rate.[14]

3.19.1. Parties' Comments

ORA opposes SCE's proposal to change the CRT rate. ORA argues that reducing the basis to which the 10% CRT is applied reduces the CRT, which could result in increased hedging and greater ratepayer costs. Furthermore, while requesting the underlying index for setting the CRT rate to be changed to the ERRA portion of the system average rate, ORA claims SCE fails to offer data on the actual ERRA portion of rates compared to its combined system average rate or to provide historic or future nonmarket cost projections to inform the record of the impacts of its proposal.

3.19.2. Discussion

The 2010 Bundled Plan Decision, D.12-01-033, changed the CRT rate from 1 cent/kwh to 10% of the system average rate so that the threshold for engaging in hedging would be higher because the Commission agreed with ORA's analysis on how much of a monthly rate increase a typical customer could tolerate. ORA's analysis demonstrated that the customer could tolerate a higher rate increase than the previous CRT allowed.

We will not adopt SCE's proposal to change the CRT rate as established in D.12-01-033, as SCE has not clearly demonstrated that a modification is necessary or in the interest of ratepayers.

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[14] SCE 2014 Draft BPP, Appendix J, sheet J-5.

3.20. Add Resource Adequacy Sales as Non-Standard Product (SCE)

Resource Adequacy (RA) sales are an authorized product in the utilities' bundled plans. Utilities are authorized to sell RA capacity when they are long in meeting their RA compliance obligations. If categorized as a standard product, utilities must transact this product through an RFO. Currently, RA sales are a standard product in SCE's bundled plan. SCE proposes to add RA sales as a non-standard product due to its unique circumstances. By designating RA sales as non-standard product, SCE can sell this product bilaterally, subject to adequate price support in the QCR, for terms longer than one quarter and/or with delivery beginning longer than one quarter forward (*i.e.*, medium-term transactions). No party commented on SCE's proposal.

3.20.1. Discussion

While the Commission in a 2012 LTPP Decision (D.14-02-040) excluded RA capacity from the list of non-standard products, RA sales differ materially from RA purchases in terms of the available quantity, potential market participants, and time-frame for transactions. We agree with SCE that bilateral sales of RA capacity in the months leading up to RA compliance obligations could benefit ratepayers and facilitate the transfer of smaller quantities of excess RA capacity to others with RA compliance obligations. For these reasons, we will allow SCE, as well as the other utilities, to classify RA sales as a non-standard product and allow them to transact RA sales bilaterally.[15]

[15] At the same time, we emphasize that RA capacity is a standard product and that RFOs are the appropriate vehicle for RA purchases.

3.21. Linkage Rule Change (SCE)

In D.14-02-040 at 40, the Commission adopted what is known as the linkage rule:

> More specifically, for the purpose of determining the "term" of a contract, two or more contracts, including contractual options, are treated as one (linked), where:
>
> a. They specify the same resource as the primary delivery source or, (2) for an unspecified source, they are with the same counter-party; and
>
> b. They are negotiated or executed within any three consecutive month period, except if entered into as a result of separate RFOs and the contract from the earlier RFO is executed before the later RFO has received any bids (either indicative or final).

The linkage rule is intended to prevent the utilities from executing multiple deals that, if evaluated as a single medium-term or long-term transaction, would exceed BPP authorization. The linkage rule specifies that two or more contracts are treated as one (linked), if they are executed with the same resource within three months for consecutive time periods. SCE proposes to modify the linkage rule adopted in D.14-02-040. Given the tradeoff between "least-cost, best-fit" alternatives and preventing the potential for combined deals in excess of Commission authorization, SCE believes that the best approach is to instead apply the linkage rule to those transactions which are of greater consequence, and which may be the focus of the Commission's concern. With that objective in mind, SCE recommends that the Commission amend the linkage rule in D.14-02-040 for the purpose of medium-term transactions to apply to tolling agreements only. No party commented on SCE's proposal.

3.21.1. Discussion

SCE has shown that the linkage rule, as written in D.14-02-040, could inadvertently create medium-term transactions from unrelated short-term transactions, and this new constraint could impede the utilities' ability to obtain the least-costly short-term products. However, we do not agree with SCE that it should be narrowly written to apply only to tolling arrangements. For example, we are also concerned about other types of potentially linked transactions (e.g., RA capacity).

To avoid inadvertently constraining the utilities with respect to short-term bilateral transactions (which we define as those contracts of nine months or less), we will modify the linkage rule to add an additional term, as follows:

> More specifically, for the purpose of determining the "term" of a contract, two or more contracts, including contractual options, are treated as one (linked), where:
>
> a. They specify the same resource as the primary delivery source or for an unspecified source, they are with the same counter-party;
>
> b. They are negotiated or executed within any three consecutive month period, except if entered into as a result of separate RFOs and the contract from the earlier RFO is executed before the later RFO has received any bids (either indicative or final*);* and
>
> c. The combined, consecutive contract term exceeds nine months.

3.22. Correct Error in SDG&E Demand Response Accounting (SDG&E)

ORA observes that SDG&E double counted demand response programs in its forecast of system peak demand in Table A-1, which uses the CEC's 2013 Integrated Energy Policy Report (IEPR) forecast. SDG&E included the entire amount of its programs rather than adjusting the values to subtract the subset of programs already included in the IEPR load forecast, i.e. critical peak pricing and peak time rebate programs. ORA recommends that SDG&E 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* (ORA Opening Comment at 15).

3.22.1. Parties' Comments

SDG&E agrees with ORA's recommendation and proposes to correct the table in the compliance filing of the Bundled Plan to eliminate the double-counting of demand response programs included in the IEPR forecast.

3.22.2. Discussion

We adopt ORA's recommendation and require SDG&E to correct the double counting of demand response programs in SDG&E' load forecast in Table A-1.

3.23. Addition of Energy Storage Product (SDG&E)

In light of the Commission's Energy Storage Decision (D.13-10-040) and SDG&E's Energy Storage Procurement Application (A.14-02-006), SDG&E has revised its product list to include energy storage products and has updated the product discussion in Section II.A.3.[16] No party commented on this revision.

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[16] SDG&E Bundled Plan, Table 1(a) Electric Procurement Products at 20.

3.23.1. Discussion

The bundled plan process is intended primarily to oversee the procurement of existing resources with contracts of less than five years in duration. In addition, D.13-10-040 and D.14-10-045 require the utilities to file applications for energy storage procurement.[17] Thus, given that most energy storage procurement is not for existing resources, and we require applications for procurement of new energy storage resources, we believe that it is premature to include energy storage in the list of authorized products as part of the bundled plan procurement process. Therefore, we will not adopt SDG&E's revision to include energy storage products in the list of authorized electric procurement products.

3.24. Other Modification in SDG&E's BPP

Subsequent to filing its draft BPP, SDG&E determined that it had incorrectly included the full capacity of the Wellhead Escondido and Pio Pico resources in Table A-1. The Commission has found that both of these resources are subject to the Commission's cost allocation methodology (CAM). Pursuant to the CAM, SDG&E will be allocated a share of the capacity, with a portion being allocated to other load serving entities that serve load in SDG&E's service territory. Accordingly, the capacity values in Table A-1 must be revised to reflect inclusion of only the portion of the Wellhead Escondido and Pio Pico resources allocated to SDG&E (not the full capacity of the resources). SDG&E requests that it be allowed to correct the capacity values in Table A-1 in the compliance filing of its Bundled Plan.

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[17] D.13-10-040, Appendix A at 11; D.14-10-045 at 104.

The above two corrections will alter SDG&E's overall capacity position. Since the procurement limits in Appendix H are based on this capacity position, SDG&E also requests permission to update the values in the procurement limit table in Appendix H in order to ensure that it is consistent with the changes discussed above (SDG&E Reply Comments at 2-3).

3.24.1. Discussion

We adopt SDG&E's proposal to make corrections of the capacity values in Table A-1 to reflect the portion of Wellhead Escondido and Pio Pico allocated to SDG&E, as well as procurement limits in Appendix H.

4. Other Party Proposals

4.1. SCE Procurement Approach Reporting (CEERT)

CEERT proposes that the Commission require SCE to publicly detail its approach and whether SCE's "least-cost/best-fit" process (in for example, SCE's local capacity requirements RFO) has been successful in enhancing procurement of preferred resources in the BPP. CEERT believes that a broader public reporting of SCE's approach utilized for each procurement is required to give confidence to all stakeholders that the outcome expected by SCE and this Commission in advancing preferred resources is realized.

SCE opposes this proposal and believes it is unnecessary. SCE states that it already provides extensive information regarding its valuation and selection process in its bidders' conference, where the various attributes being evaluated, the preferences, and the optimization approach are described in detail. All bidders are provided this information in advance and are given an opportunity to ask questions about the process. Further, SCE describes the specifics of each valuation process to its PRG and Energy Division. In addition, SCE utilizes an Independent Evaluator to ensure that all resources are treated fairly.

We agree that the current process requires sufficient disclosure of SCE's procurement activities. Therefore, we will not adopt CEERT's proposal.

4.2. Loading Order Compliance

4.2.1. Sierra Club/CEJA Proposal

Sierra Club and CEJA propose that loading order should be considered with each transaction and that the Commission require the utilities to include a description of how they have complied with the loading order in the quarterly reports.

PG&E, SCE, and SDG&E oppose this proposal. PG&E asserts that CEJA's argument is based on a misunderstanding of D.12-01-033 and PG&E's 2014 BPP. In D.12-01-033, the Commission directed the utilities to procure loading order resources, such as energy efficiency or demand response, "to the extent they are feasibly available and cost effective."[18] Nowhere in D.12-01-033 did the Commission require the utilities to consider the loading order for each transaction. SDG&E also believes Sierra Club and CEJA have misconstrued SDG&E's 2014 BPP. SDG&E will pursue preferred resources to the extent it's feasible, available, and cost-effective.

D.12-01-033 required the utilities to procure as much preferred resources as feasibly available and cost effective before procuring conventional resources. By this standard, the utilities would have exhausted cost effective and feasible

[18] D.12-01-033 at 21.

preferred resources before procuring conventional resources. Sierra Club and CEJA's proposal to require the utilities to demonstrate compliance with the loading order with each transaction is burdensome and not required by D.12-01-033. Therefore, we will not adopt this proposal.

4.2.2. Loading Order (CAC and EPUC)

CAC and EPUC contend that both PG&E and SCE's BPPs fail to provide a mechanism for fully exhausting the Loading Order before procuring other, conventional resources. CAC and EPUC suggest that the utilities in these bundled plans seem to measure satisfactory procurement of Combined Heat and Power (CHP) resources solely by meeting their targets under the Qualifying Facility (QF)/CHP Settlement Agreement approved in D.10-12-035. CAC and EPUC also suggest that the utilities fail to recognize that they have an on-going, independent obligation to procure CHP regardless of whether they have met the procurement target under the Settlement. They recommend that the Commission direct SCE and PG&E to revise their procurement procedures so that preferred resources within the loading order are evaluated exclusively first to fill an identified shortage.

CAC and EPUC assert that the second issue concerning compliance with the Loading Order is that the bundled plans rely on the use of all-source RFOs and the "least cost/best fit" metric. They assert that these mechanisms are generally inconsistent with the Loading Order and are not designed to fully recognize the benefits of preferred resources. They recommend that the utilities must be directed to tailor their RFOs so that the "best fit" is focused on the preferred resources, and least cost is only applied within the priorities of the Loading Order.

PG&E opposes these proposals. PG&E contends that CAC offers no citation or Commission precedent to support their assertion that "least cost" is not appropriate for preferred resources and thus, for these resources, the utilities should simply look at "best-fit."

The QF/CHP Settlement, executed in part pursuant to the EAP (Settlement Agreement Term Sheet Section 1.2.1.2), included provisions for utility procurement of CHP to be based on the utilities' analysis of their market value. Foremost, the Settlement specifically gives the utilities the ability to justify not procuring CHP for reasons of high cost, lack of need, or ill portfolio fit (Settlement Agreement Term Sheet Sections 5.4 and 6.9). Review of CHP procurement was required in the Settlement Agreement, and D.15-06-028 established utility CHP procurements by considering the EAP among other objectives. We agree with PG&E that the Commission ordered the utilities to use the least cost/best fit methodology to evaluate their RFOs and that notwithstanding the requirement to comply with the Loading Order, the utilities are required to consider cost as a metric in their evaluation of the bids received in CHP-only or other RFOs. Therefore, we do not adopt CAC and EPUC's proposal.

4.3. Proposed Motion for New Products and Fossil Fuel Procurement (Sierra Club/CEJA)

Sierra Club and CEJA propose that the Commission require the utilities to file a motion in the LTPP proceeding when requesting new products, new fossil-fuel procurement and substantive changes to their BPPs.

PG&E, SCE, and SDG&E oppose this proposal. PG&E asserts that it is a collateral attack on existing Commission decisions and is without merit. PG&E argues that if Sierra Club and CEJA intend to modify Commission decisions, the correct procedure is through a petition for modification. SDG&E believes that requiring the utilities to submit a motion in the LTPP creates administrative burden and serves no discernable purpose.

New need determination is currently litigated in the LTPP proceedings and not authorized through the utilities' BPPs. The Advice Letter process is the appropriate vehicle for the utilities' requests to add new products and other changes in the years that Bundled Plans are not reviewed in the LTPP. We agree that requiring the utilities to submit a motion in the LTPP serves no discernable purpose. Therefore, we do not adopt this proposal.

4.4. BPP Confidentiality (Sierra Club/CEJA)

Sierra Club and CEJA observe that the utilities redact confidential information differently in their BPPs. They show four instances where the utilities redact information inconsistently – Qualifying Facility contractual resources, capacity balance summary, hedging strategy, and redaction of section titles. They propose that the Commission require the utilities to redact information consistently.

ORA supports this proposal. ORA asserts that redacting information that is not market sensitive hinders transparency in the public process. Utilities should ensure that the information they are redacting falls under market sensitive information addressed in D.06-06-066.

PG&E, SCE, and SDG&E oppose this proposal. SDG&E believes it violates § 454.5(g) and D.06-06-066 regarding confidential information. PG&E opposes this proposal as untimely. PG&E argues that the procedure for challenging these redactions was to file a response to PG&E's motion for leave to file confidential material under seal on October 3, 2014 under Rule 11.4(b), which CEJA did not do.

D.06-06-066 specified guidelines for redacting market-sensitive information. This guidance remains in effect and there is no need to revisit such issues here. We agree that the utilities should be consistent in redacting market-sensitive information. This issue will be considered, as appropriate, in the next refinement of the procurement rules.

4.5. Transparency and Public Participation in Future Procurement Activities (Sierra Club/CEJA)

Sierra Club and CEJA propose that the Commission ensure transparency by improving the quarterly reports and requiring transparency and oversight for proposed procurement plans. CEJA and Sierra Club recommend that the Commission mandate that the QCR revision process ordered in the 2012 LTPP Track III Decision be completed by the time the Commission approves the bundled plans. The Commission should also require formal notice and comment on proposed procurement plans submitted by utilities. Additionally, the Commission should increase transparency and boost public confidence by requiring Commission approval of the proposed procurement plan.

ORA supports the proposal to require a more transparent public participation process in the utilities' procurement plans and recommends that the utilities be required to serve any Commission-determined procurement plan on the service list of the appropriate proceeding to allow for stakeholder input and ensure transparency.

PG&E, SCE, and SDG&E oppose this proposal. SDG&E asserts that Sierra Club and CEJA's arguments in favor of formal review of process documents lacks merit. SDG&E believes that the requirement to prepare process documents in Track 1 and 4 of the 2012 LTPP creates confusion regarding the significance of the Commission "approval" of the document and should be eliminated from future procurement. PG&E argues that it has been compliant with the requirements in D.14-02-040 and filed a joint report on proposed QCR revision on May 28, 2014.

The stakeholder process for the QCR revision ordered in D.14-02-040 has been initiated, as PG&E stated. However, this process is still on-going and will require more time for Energy Division, the utilities, and parties to complete. We do not believe that there is a benefit to delaying the bundled plan process to allow the QCR revision process to be completed. Therefore, we deny this proposal.

Sierra Club and CEJA's proposal to require a formal process for the utilities' procurement plans pursuant to Commission authorization to procure new resources is outside the scope of this Phase of the proceeding. The requirement to submit procurement plans for authorized new resources was ordered by decisions D.13-02-015 and D.14-03-004 in the 2012 LTPP proceeding. Sierra Club and CEJA's proposal to require a formal process for procurement plans should be considered in the proceeding that authorized the new resources and ordered the submission and approval of a procurement plan. Therefore, we do not adopt this proposal.

4.6. GHG Offsets (Sierra Club/CEJA)

Sierra Club and CEJA recommend that the utilities minimize reliance on offsets.

SCE opposes this proposal. SCE states that there are already limitations on the extent to which utilities may rely on offsets.

CARB's Cap-and-Trade Regulation limits the use of offsets to 8% of an entity's compliance obligation.[19] D.12-04-046 sets the following requirements on utility purchase of offsets: (1) may only procure offsets certified by CARB, (2) may purchase no more than 8% of their compliance requirement in the form of offsets,

[19] Cap-and-Trade Regulation § 95854.

and (3) can only purchase offsets if the seller contractually assumes the risk of invalidation.[20] We do not find it necessary at this time to further restrict the use of offsets.

4.7. CCA and DA Departing Load Forecast

4.7.1. MCE Proposal

MCE provides three proposals. First, MCE requests that the Commission recognize MCE's long-term resource planning and procurement to meet its customers' resource needs. MCE uses a 10-year forward-looking planning period for what it calls an Integrated Resource Plan (IRP) that is adopted by the MCE board on an annual basis. The IRP quantifies resource needs over the planning period and sets procurement policies. MCE attached a copy of its draft Integrated Resources Plan. MCE requests that the Commission take official notice of it to inform the Commission and parties of issues related to PG&E's BPP and other issues.

Second, MCE recommends that in accordance with D.14-02-040, and consistent with the approach taken by PG&E, SCE should be required to modify its BPP so that its load forecast reflects reasonable amounts of departing load associated with Lancaster's CCA program.

Third, based on the history of CCA development over the last five years, MCE believes it is appropriate to modify the Commission's previous determination with respect to CCA departing load. More specifically, based on historical trends, MCE claims it is now appropriate to implicitly reflect CCA

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[20] D.12-04-046 Ordering Paragraph 7.

departing load in PG&E's load forecasts in a manner that is comparable to municipal departing load and customer generation departing load. This means unless CCA departing load materially differs from historical trends, CCA departing load cost responsibility would be set at a 2009 vintage.

SCE opposes MCE's proposal to require SCE to modify its load forecast to reflect departing load associated with Lancaster's CCA program because there were no operational CCAs in SCE's service area at the time SCE's BPP was submitted in October 2014, and no Binding Notice of Intent had been submitted to inform SCE of procurement decisions to meet its load and resource adequacy requirements.

PG&E and SCE also oppose MCE's proposal to modify departing load rules and state it is outside of the scope of Phase II.

We decline to take official notice of MCE's draft Integrated Resources Plan, as it is not a final adopted document of a governmental agency.

Lancaster's CCA program has been operating since May 2015. To be consistent with PG&E's load forecasting methodology (discussed elsewhere in this decision), we require SCE to revise its Trajectory Scenario to reflect the departing load due to CCAs such as Lancaster.

MCE's proposal to modify departing load rules is outside of the scope of the bundled plan review. This issue may be considered in the next review of procurement rules.

4.7.2. AReM Proposal

AReM has two proposals on departing load rules. First, AReM proposes that the Commission should require the utilities to: (a) develop consistent and accurate forecasts of departing DA load based on the maximum allowable under the law; (b) demonstrate that they have removed such DA departing load from their forecasts; and (c) make these forecasts publicly available.

SDG&E opposes this proposal because DA providers would benefit from a forecasting approach that maximizes the estimated departing load in the utilities' bundled plans and allows DA providers to secure a more favorable Power Charge Indifference Adjustment (PCIA) vintage (*i.e.*, an earlier vintage, which limits the commodity costs they are obligated to pay). This benefit to DA providers would significantly harm ratepayers, however, who would be required to absorb additional commodity costs in contravention of the ratepayer indifference objective.

D.14-02-040 already requires that the utilities estimate reasonable levels of expected DA load over the 10-year bundled load forecast period. AReM seeks to change it to maximum allowable under the law. AReM does not provide a persuasive argument as to why we should change the rule adopted in D.14-02-040. Therefore, we do not adopt AReM's proposal.

Second, DA departing load is capped pursuant to existing statute and the cap is full. Because this capped load quantity is deducted for purposes of bundled procurement planning, AReM proposes that any vintages created for DA customers for purposes of the PCIA should include no new utility procurement costs incurred after the issuance of D.14-02-040. In addition, subtracting CCA load from the bundled procurement requirements should mean that any PCIA vintages created for such departing load should have fixed portfolios as of the date of the forecast and the utilities should be prohibited from recovering stranded costs through the PCIA associated with any new procurement that occurs after that date. This approach would also apply for new DA departing load, if the current cap on DA load is lifted or increased.

SDG&E opposes this proposal and believes that the adoption of AReM's proposal to assign a 2014 PCIA vintage to all future departing DA load up to the statutory cap would allow future DA departing load to unfairly shift costs to utility ratepayers. It benefits DA providers at the expense of utility ratepayers and is therefore not in the public interest. SCE asserts that it has reached its total DA cap in June 2014. SCE believes that to the extent that the DA load remains at the capped level, it is appropriate to assign customers who depart for DA service to the 2014 PCIA vintage. If the statutory cap is increased to a fixed level, SCE proposes that new DA customers be assigned to the PCIA vintage year in which the increased DA cap is first accounted for in SCE's long term forecast. If the statutory cap is lifted, SCE proposes that new DA customers be assigned to vintages based on the guidelines outlined in D.08-09-012. SCE recommends that the Commission reject AReM's proposal.

We will not adopt AReM's proposal. This issue may be considered in the next review of procurement Rules in a future LTPP proceeding.

4.8. CHP as Distributed Generation (CAC/EPUC)

CAC and EPUC state that PG&E characterizes CHP as part of conventional resources, and does not identify it as a preferred resource and requests that this be corrected. They contend that the loading order is clear that CHP is a component of distributed generation.

PG&E opposes this proposal because it claims EPUC/CAC fails to provide any citation or authority to support this broad assertion that CHP is a preferred resource in the Loading Order. PG&E argues that the EAP defines the loading order as: 1) energy efficiency; 2) demand response; 3) renewable resources; 4) distributed generation; and 5) clean conventional generation. Although the EAP refers to some CHP as distributed generation, not all CHP constitutes distributed generation. Many CHP facilities are large generating facilities that simply provide some thermal energy to a nearby thermal host, which are not the type of distributed generation envisioned in the EAP.

The 2003 EAP[21] does not identify specific "Distributed Generation" resource types or technologies other than with non-technical adjectives (efficient, clean, small, local, and renewable). The EAP II [22] and 2008 EAP Update [23] are clearer, but qualitatively identify "CHP applications" as distributed generation. We agree with PG&E in a limited case that not all CHP can be characterized as distributed generation, particularly if they are large, away from load centers, and transmission-connected. Consistent with D.15-06-028, the nature of the grid conditions that motivated the EAPs in 2003 and 2008 and the value of electricity from CHP have changed.[24] D.15-06-028 reaffirmed that CHP is considered a preferred resource in the State's "Loading Order" and in statute.[25] However, we agree with PG&E and clarify that not all CHP can necessarily be classified as distributed generation. Therefore, we do not adopt CAC and EPUC's proposal.

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[21] 2003 Energy Action Plan at 7, http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.

[22] EAP II at 2, http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

[23] 2008 EAP Update at 15, http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31EBE7/0/2008_EAP_UPDATE.PDF.

[24] D.15-06-028, Finding of Fact 13.

[25] D.15-06-028, Finding of Fact 5.

4.9. Reporting Requirements for Non-Compliant Transactions (ORA)

ORA proposes that the Commission develop utility reporting requirements for non-compliant transactions. ORA recommends that the Commission direct the utilities 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:
   a. When the transaction(s) took place,
   b. The type of transaction(s) involved,
   c. The financial size of the transaction(s) and the net profit or loss at the time of this report, and
   d. 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," 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 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.

Sierra Club and CEJA support this proposal. Sierra Club and CEJA agree with ORA that noncompliant transactions must be met with a plan of action and that any costs incurred by the utility due to a noncompliant transaction should be assumed by the utility and not passed onto its customers. SCE opposes this proposal. SCE believes that the QCR process is the appropriate vehicle for reporting noncompliant transactions. PG&E supports ORA's proposed reporting requirements, but recommends modification of the timing. Given the complexity of many procurement transactions, and the time-consuming nature of the review, PG&E recommends that notice be provided to the Commission within 15 business days and that a plan for prospective action be provided within 45 business days.

We find ORA's proposal to develop a process to report non-compliant transactions reasonable because it increases transparency and accountability. Therefore, we adopt the proposal with respect to the reporting requirement. Issues regarding prudence, reasonableness, and cost-recovery should be addressed when these transactions are reviewed.

4.10. Independent Review of Hedging Plans (ORA)

ORA proposes that the Commission provide more guidance and oversight on the utilities' hedging plans. ORA argues that the current hedging oversight of requiring the utilities to use a TEVaR analysis and applying the CRT is not sufficient. The TEVaR analysis is performed using unique software programs without standardized assumptions or transparency. ORA proposes a hedging assessment performed by an independent firm with the expertise to analyze all aspects of the Commission's hedging guidelines and the utilities' hedging practices. The goal of this assessment would be to provide the Commission with a summary of the utilities' 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 to be developed by the Commission with input from stakeholders.

PG&E, SCE, and Reid oppose ORA's proposal. PG&E states that ORA made the same request in the 2010 BPP proceeding, and the decision denied this request. The utilities already review their hedging plans with the PRG. This proposal will still be costly, time-consuming, and will likely result in little additional benefit. SCE agrees with PG&E and states that SCE's TEVaR model has been reviewed and approved by a third-party, Bates White LLC, in Resolution E-4365. Reid believes that ORA has the ability to hire a consultant to review the utilities' risk management plans and has done so previously. He also argues that ORA does not discuss whether the ratepayers will be required to pay for the proposed services of an independent firm nor provide an estimated budget for this service.

We are not convinced that a new need for an independent assessment of the utilities' hedging plans has arisen since the 2010 BPP proceeding. Therefore, we do not adopt ORA's proposal.

5. Issues Outside of the Scope of Phase II

5.1. Provider of Last Resort (PG&E)

PG&E states that the BPP raises important questions about its role as a provider of last resort that should be fully explored in this proceeding or elsewhere, including alternative provider of last resort models that would improve the competitiveness of wholesale and retail markets.

MCE endorses the call to examine provider of last resort issues, noting that such issues have a key bearing on LTPP issues. MCE also noted that the CCA development had affected the provider of last resort landscape.

SCE asserts that this portion of the proceeding addresses procurement for bundled customers pursuant to AB 57 only, and thus issues pertaining to all customers are out of scope.

We agree that this proposal is outside of the scope of review of the BPPs.

5.2. Marginal Abatement Cost for GHG Emissions (Sierra Club/CEJA)

Sierra Club and CEJA suggest that utilities should evaluate emissions reductions as a way to mitigate financial risk. They recommended that each utility develop a marginal abatement cost curve to compare GHG reduction costs to potential costs incurred by continued emissions, including an assessment of potential compliance failures at least annually in the BPPs.

SCE opposes this proposal. SCE argues that the cost of carbon used in these valuations should be the market price for compliance instruments, not a marginal abatement cost (MAC) curve. As a comparison, utilities use the market price for natural gas when forecasting costs of natural gas burning resources, not a natural gas production supply curve. The market is much more dynamic and efficient in pricing natural gas and carbon than relying on production cost curves or MAC curves. The relevant analysis can be performed without the need or requirement to establish a MAC curve. Therefore, CEJA and Sierra Club's proposal should be rejected.

The issue is out of scope of the review of BPPs.

5.3. Environmental Justice Consideration (Sierra Club/CEJA)

Sierra Club and CEJA propose that environmental justice should be included as a consideration in the utilities' BPPs. The BPPs should include language that supports prioritizing renewable and preferred resources in environmental justice, or disadvantaged, communities.

PG&E, SCE, and SDG&E oppose this proposal. PG&E believes that rather than addressing this issue in the BPP, environmental justice issues should be considered in the context of specific solicitations as the issues addressed in specific solicitations may vary. SDG&E asserts that "environmental stewardship" and "benefits to minority and low income areas" are qualitative factors used in the least-cost, best-fit evaluation of potential resource additions. SCE states that Sierra Club and CEJA's comments are more appropriately addressed in the context of system procurement or procurement through preferred resources programs such as RPS. Further, siting of conventional resources is outside of the scope of SCE's residual bundled procurement.

We agree that procurement of preferred resources and siting of conventional resources are outside of the scope of the BPPs. Therefore, we do not adopt Sierra Club/CEJA's proposal.

5.4. Renewal of CHP Contracts (CAC/EPUC)

CAC and EPUC state that neither PG&E nor SCE's plan provides the means to achieve re-contracting beyond the expiration date of December 31, 2024 or preserve the availability of existing efficient CHP. CAC and EPUC also assert that many existing CHP resources have not been offered renewal contracts by their interconnected utilities. They request a decision that directs the utilities to offer a contract extension or renewal to all of their current CHP resources whose contracts have expired or will expire prior to 2024.

PG&E, SCE and SDG&E oppose this proposal. SDG&E believes this proposal is outside of the scope of Phase II and the issues are being addressed via an Administrative Law Judge (ALJ) Ruling in the 2014 LTPP proceeding. PG&E argues that CAC offers no legal or factual basis to support this recommendation. The QF/CHP Settlement included provisions for contracts extensions and re-contracting on a limited basis through 2015. After the Transition Period, which ends on July 1, 2015, existing CHP resources that have not been procured are required to participate in utility solicitations or sell their energy and capacity through existing market mechanisms. SCE concurs with PG&E that a mandatory obligation to purchase all CHP, regardless of its qualities, is in direct conflict with the CHP Settlement.

CAC and EPUC's proposal presumes that the CHP facility will necessarily shut down without a contract. We have no substantive basis to assume that an existing CHP facility would shut down absent a contract. Enabling non-competitive CHPs that have not secured a seven-year PPA by the end of the Initial Program Period to participate in the wholesale CAISO energy market (without utility contracts) is a key element of the Settlement's Transition to a post-Public Utility Regulatory Policies Act or must-take program. This issue was addressed in the current 2014 LTPP proceeding R.13-12-010 in D.15-06-028. We agree that this issue is outside of the scope of this phase. Therefore, we do not adopt this proposal.

5.5. Incorporate Demand Response into Least Cost Dispatch (ORA)

The Commission set forth seven minimum standards of behavior to guide the utilities' management of their portfolios of generation and contracted resources in D.02-10-062. Standard of Conduct 4 states "the utilities shall prudently administer all contracts and generation resources and dispatch energy in a
least-cost manner."[26] ORA proposes to evaluate all dispatchable resources under the Commission's Least Cost Dispatch (LCD) standard, including Demand Response resources with an economic trigger.

Sierra Club/CEJA support this proposal and request that LCD apply to energy storage as well. SCE opposes this proposal and states that the issues are being addressed in the utilities open ERRA review proceedings for the 2010 Record Periods. SDG&E opposes this proposal on the grounds that the proposed reporting requirement is duplicative, burdensome and would create the potential for confusion and double-counting. PG&E agrees with SCE that this issue is already being actively addressed in two other Commission proceedings, the 2010 and PG&E's 2013 ERRA compliance proceeding and thus need not be addressed here.

We agree that this issue is outside of the scope of this proceeding and belongs in the utilities' ERRA proceedings. We defer this issue to be reviewed in the utilities' ERRA proceedings.

[26] D.02-10-062 at 51.

5.6. GHGs Considered in All Source RFOs (WBA)

WBA comments on the valuation of GHG emissions in the context of SCE's all source RFO. WBA urges the Commission to incorporate GHG emissions (or the lack thereof) as a component in evaluating a resource's suitability for inclusion using the All Source RFO process. WBA suggests a need to develop a precise methodology that best quantifies the true cost or benefit of a resource's GHG emissions, which will allow for a more accurate valuation of preferred and conventional resources in an all-source RFO process. No party commented on this proposal.

This issue is out of scope of the BPPs and will not be considered here.

5.7. Clean Energy Moonshot Initiative (WBA)

WBA discusses at length their initiative on long-term energy goals and environmental policies of GHG reduction. They advocate for microgrids and fuel cells for a clean energy future in California. SCE opposes WBA's proposals on environmental policy and contends they are outside of the scope of Phase II.

We agree that WBA's initiative is outside of the scope of this phase of this proceeding, which does not include long term energy and environmental policies that lead to new resources and energy infrastructure.

6. Comments on the Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ________, and reply comments were filed on _________ by ____________.

7. Assignment of Proceeding

Michael Picker is the assigned Commissioner and David M. Gamson is the assigned ALJ and presiding officer in this proceeding.

Findings of Fact

1. The Commission authorized the utilities to submit ERR contracts with terms of less than five years through a Tier 1 Advice Letter process in D.14-11-042.
2. CARB has now held a successful GHG allowance auction, providing evidence of a competitive GHG procurement market.
3. In D.14-12-040, the Commission authorized the natural gas utilities to procure GHG compliance instruments through brokers or exchanges that have been pre-approved by the Commission through a Tier 2 Advice Letter filing.
4. The Advice Letter process for procurement limits and ratable rates can be streamlined.
5. The review of the utilities' conformed BPPs is ministerial as it would not result in changes to existing policies.
6. The PRG may require significant background in a short period of time regarding convergent bidding and related circumstances.
7. The utilities were instructed in the May 6, 2014 Scoping Memo to file BPPs based on the trajectory scenario of the Assumptions, Scenarios, and RPS adopted for use in a February 27, 2014 ruling.
8. PG&E submitted a BPP analysis based on alternative assumptions to the trajectory scenario, which included modified assumptions for departing load and distributed generation.
9. The increase in distributed generation and consistent level of DA in PG&E's alternate scenario are not significant for planning purposes and do not necessitate

a change from the trajectory scenario. However, PG&E's calculation of departing CCA load includes more accurate data than the trajectory scenario.

10. PG&E has provided sufficient information, much of which is in confidential form, to justify its proposed changes to its hedging plan.

11. PG&E's proposed inclusion of a GHG financial exposure purchase limit was calculated in accordance with the formula established in D.12-04-046.

12. PG&E has proposed in confidential filings a number of changes to its hedging program.

13. PG&E's BPP proposal to manage aspects of its portfolio other than financial risks, such as operational flexibility, through procurement of various electric products is limited to already authorized procurement.

14. All bundled procurement transactions over three months are subject to review by the PRG at this time.

15. PG&E was previously approved to access various brokerages including ICE.

16. Removing the value of the GHGs from the implied market heat rate would restore the prior metric put in place by the Commission in our earlier decisions and remove a disincentive for cost-effective procurement.

17. Because safety should be incorporated into the utility procurement process, including the offer evaluation process and the assignment of responsibilities between generators and the utilities for the safe operation of facilities, there is no need for a separate safety phase of this proceeding.

18. The CRT rate was established in D.12-01-033.

19. The linkage rule, as written in D.14-02-040, could inadvertently create medium-term transactions from unrelated short-term transactions, which could impede the utilities' ability to obtain the least-costly short-term products.

20. The bundled plan process is intended primarily to oversee the procurement of existing resources with contracts of less than five years in duration. Most energy storage procurement is not for existing resources.

21. MCE's IRP is not a final adopted document of a governmental agency.

22. Lancaster's CCA program has been operating since May 2015.

Conclusions of Law

1. Pub. Util. Code § 454.5 provides that approval of the BPPs (as appropriately modified by the Commission) obviates the need for after-the-fact reasonableness review by the Commission of the resulting utility procurement decisions that are consistent with the approved plans.

2. This decision excludes consideration of much procurement done by the utilities. This decision is not intended to result in any new generation facilities being constructed, and continues to implement the Commission's loading order and EAP.

3. The Commission's guidance regarding BPPs in D.12-01-033 at 3 remains in effect.

4. The issue of approval of ERR contracts with terms of less than five years was decided in D.14-11-042 and should not be reconsidered in this decision.

5. The utilities should be allowed to use brokers to procure GHG allowances and offsets.

6. It is reasonable to allow the utilities to each submit one Tier 1 Advice Letter for all procurement limits, including GHG procurement limits.

7. SCE's proposal to allow the utilities to file a Tier 2 Advice Letter for approval of their conformed BPPs is reasonable and should be adopted.

8. It is reasonable that each of the utilities should be required to inform their respective PRGs within three (3) business days when their 365-day rolling average

net-loss exceeds their respective limits and under the three additional circumstances described by Reid.

9. PG&E's alternative scenario revisions to reflect departing load due to CCAs are reasonable and should be adopted.

10. PG&E's proposed changes regarding risk management improvements, and certain confidential matters, should be adopted to the extent they do not conflict with D.12-01-033, which held that "Any contract that seeks to impose additional liability for nuclear accidents on Pacific Gas and Electric Company and its ratepayers must be approved by an application, not an advice letter."

11. PG&E's proposed changes to its hedging plan are reasonable and should be adopted.

12. PG&E's proposed inclusion of a GHG financial exposure purchase limit is reasonable.

13. PG&E has justified in confidential filings its proposed changes to its hedging program.

14. Utilities have been granted authority in previous decisions to procure existing flexible products.

15. PG&E has not provided sufficient rationale to justify a change to the current requirement to consult with the PRG for transactions over three months.

16. PG&E's proposal to remove the value of the GHGs from the implied market heat rate is reasonable and should be adopted.

17. SCE's proposal to change the CRT rate as established in D.12-01-033 has not clearly demonstrated that a modification is necessary or in the interest of ratepayers.

18. The linkage rule should be modified to avoid inadvertently constraining the utilities with respect to short-term bilateral transactions of nine months or less.

19. SDG&E should correct the double counting of demand response programs in SDG&E' load forecast in Table A-1 of its BPP.

20. It is premature to include energy storage in the list of authorized products as part of the bundled procurement plan process.

21. SDG&E's should make corrections of the capacity values in Table A-1 of its BPP to reflect the portion of Wellhead Escondido and Pio Pico allocated to SDG&E, as well as procurement limits in Appendix H of the BPP.

22. The Commission should not take official notice of MCE's draft Integrated Resources Plan.

23. To be consistent with PG&E's load forecasting methodology, SCE should revise its Trajectory Scenario to reflect the departing load due to CCAs such as Lancaster.

24. ORA's proposal to develop a process to report non-compliant transactions is reasonable.

25. Issues pertaining to intermittency in a properly designed microgrid system, closing the Diablo Canyon Power Plant, provider of last resort, marginal abatement cost for GHG emissions, a formal process for approval of utilities' procurement plans pursuant to Commission authorization to procure new resources, environmental justice considerations, renewal of CHP contracts, incorporation of demand response into least cost dispatch, GHGs considered in all source RFOs, departing load rules, and a clean energy moonshot initiative are outside the scope of this proceeding.

O R D E R

IT IS ORDERED that:

1. Pursuant to Public Utilities Code Section 454.5 (b), the 2014 Bundled Procurement Plans (BPPs) filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, "the utilities") are approved, as modified as follows:

    a. The utilities' request to enter into transaction with Eligible Renewable Resources (ERR) with terms less than five years through the BPP process is denied. The utilities shall remove ERR from the list of authorized products in their final 2014 BPPs.

    b. The utilities are authorized to procure allowances and offsets through brokers. The utilities shall report the brokered transactions in their Quarterly Compliance Reports and provide a strong showing of why brokered transactions are used in these reports.

    c. The utilities are authorized to each file one Tier 1 Advice Letter for their natural gas, electricity position limits and greenhouse gas procurement limits during years in which the utilities do not file an updated conformed Bundled Procurement Plan.

    d. The utilities shall notify the Procurement Review Group (PRG) within three (3) business days when their 365-day rolling average net-loss exceeds their respective limits and under the following three additional circumstances:

        1. Notice from the California Independent System Operator (CAISO) or its Department of Market Monitoring that PG&E or its scheduling coordinator is subject of an investigation pursuant to the CAISO Tariff.

2. Notice from the CAISO that the conduct of PG&E or its scheduling coordinator has been referred to the Federal Energy Regulatory Commission by CAISO pursuant to the CAISO Tariff.

3. Notice from the CAISO that PG&E or its scheduling coordinator's convergence bidding trading has been suspended or limited by the CAISO.

e. PG&E shall revise its forecasts for departing load pursuant to the Commission's trajectory scenario for load forecast to reflect departing load due to Community Choice Aggregators.

f. PG&E's Nuclear Fuel Procurement Plan is approved, and PG&E shall adhere to language in Decision 12-01-033, Ordering Paragraph 12: "Any contract that seeks to impose additional liability for nuclear accidents on Pacific Gas and Electric Company and its ratepayers must be approved by an application, not an advice letter."

g. The factors used in PG&E's limits shall not be changed.

h. PG&E's proposal to execute transactions greater than 90 days without PRG review is denied.

i. PG&E is permitted to make the changes regarding implied market heat rates in Appendix C, pp. 65-67, of its 2014 Bundled Procurement Plan with the condition that PG&E provide a report to Energy Division and the PRG showing the effect of the change on the first applicable year by December 31, 2016.

j. PG&E's proposal to establish an additional phase focusing solely on safety in Rulemaking 13-12-010 is denied.

k. SCE's modification to add demand-side energy efficiency, demand response, distributed generation, and renewable power to the list of authorized products is denied.

l. SCE's proposal to change the customer risk tolerance is denied.

m. SCE is authorized to add resource adequacy sales as a non-standard product.

n. The so-called "Linkage Rule" adopted in Decision 14-02-040 at 40 is modified as follows (additions underlined):

More specifically, for the purpose of determining the "term" of a contract, two or more contracts, including contractual options, are treated as one (linked), where:

1. They specify the same resource as the primary delivery source or for an unspecified source, they are with the same counter-party; and
2. They are negotiated or executed within any three consecutive month period, except if entered into as a result of separate Request for Offers (RFOs) and the contract from the earlier RFO is executed before the later RFO has received any bids (either indicative or final); <u>and</u>
3. <u>The combined, consecutive contract term exceeds nine months.</u>

o. SCE shall revise the Trajectory Scenario of their load forecast to reflect departing load due to Community Choice Aggregators.

p. SDG&E shall correct the double counting of demand response programs in SDG&E's load forecast in Table A-1.

q. SDG&E shall make corrections of the capacity values in Table A-1 of its Bundled Procurement Plan to reflect the portion of the Wellhead Escondido and Pio Pico plants allocated to SDG&E, as well as procurement limits in Appendix H.

r. SDG&E's proposed modification to add energy storage to the list of authorized product is denied.

2. In the event that future non-compliant transactions are discovered, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall do all of the following:

a. 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:

1. When the transaction(s) took place;
2. The type of transaction(s) involved;
3. The financial size of the transaction(s) and the net profit or loss at the time of this report; and
4. 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.

b. Within thirty (30) business days of identifying and verifying non-compliant transaction(s), provide a corrective plan of action.

c. Schedule a Procurement Review Group 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.

3. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 Advice Letter to conform their Bundled Procurement Plans to incorporate the modifications made in this decision no later than 90 days from the effective date of this decision.

4. The November 4, 2014 Office of Ratepayer Advocates (ORA) "Motion for Leave to File Confidential Version of ORA's Comments on the Proposed Bundled Procurement Plans of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company Under Seal" is granted. The November 4, 2014 L. Jan Reid "Motion for Leave to File Confidential Materials Under Seal" is granted. The November 20, 2014 ORA "Motion for leave to file confidential material under seal" is granted. The November 20, 2014 Pacific Gas

and Electric Company "Motion to File Under Seal Confidential Version of Reply Comments on Proposed Bundled Procurement Plan" is granted.

5. Rulemaking 13-12-010 remains open.

This order is effective today.

Dated ______________________________, at Sacramento, California.