STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

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

January 28, 2014

Agenda ID #12720
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 12-03-014:

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 February 27, 2014 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.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

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

KVC:sbf

Attachment

ALJ/DMG/sbf **PROPOSED DECISION** Agenda ID #12720

Ratesetting

Decision **PROPOSED DECISION OF ALJ GAMSON** (Mailed 1/28/14)

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 12-03-014 (Filed March 22, 2012)

DECISION MODIFYING LONG-TERM PROCUREMENT PLANNING RULES

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DECISION MODIFYING LONG-TERM PROCUREMENT PLANNING RULES

1. Summary

This is the Track 3 decision in the 2012 long-term procurement plans proceeding, regarding long-term procurement rules. This decision makes several rule changes for utility procurement of electricity in California:

1) Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company (collectively, the IOUs) shall estimate reasonable levels of expected Direct Access (DA) and Community Choice Aggregation (CCA) departing load over the 10-year term of the IOUs bundled plans, using information provided by the California Energy Commission and/or by a CCA in its Binding Notice of Intent. The IOUs shall then exclude this departing load from their future bundled procurement plans, and only procure for the assumed amounts of retained bundled load. Having been excluded from the bundled portfolio planning scenarios, the forecasted Direct Access and Community Choice Aggregation departing load shall not be subject to non-bypassable charges for any incremental stranded procurement costs incurred by the IOUs for the period after the date of departure assumed in their approved bundled plans.
2) In order to allow incremental capacity to bid into a new generation Request for Offers, the term “incremental capacity” is defined as: “capacity incremental to what was assumed in the underlying needs assessment.” In addition, the terms “upgraded plants” and “repowered plants” are also defined.
3) The IOUs shall submit Tier II Advice Letters seeking Commission approval to enter into a medium-term bilateral contract if the size of the contract is over 50 megawatts. This rule is in addition to all previous procurement rules.
4) Energy auctions shall no longer be required to net capacity costs for facilities subject to the Cost Allocation Mechanism. Instead, the IOUs shall use the mechanism adopted in Decision 07-09-044, known as the “Joint Parties’ Proposal,” to set the residual capacity costs that

would be allocated to benefitting customers.

5) Independent evaluators shall remain in the selection pool without term limits, subject to evaluation every three years instead of every two years.

2. Background

This proceeding is the successor proceeding to rulemakings dating back to 2001 intended to ensure that California's major investor-owned utilities (IOUs) can maintain electric supply procurement responsibilities on behalf of their customers. The most recent predecessor to this proceeding was Rulemaking (R.) 10-05-006. As stated in the order originating this rulemaking in Ordering Paragraph 3, the record developed in R.10-05-006 is "fully available for consideration in this proceeding" and is therefore incorporated into the record of this proceeding.

In the Scoping Memo for this proceeding, issued on May 17, 2012, the general issues for the 2012 procurement planning cycle were divided into three topics:

1. Identify Commission-jurisdictional needs for new resources to meet local or system resource adequacy (RA), renewable integration, or other requirements and to consider authorization of IOU 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 technology (OTC);
2. Update, and review individual IOU bundled procurement plans consistent with Public Utilities Code Section 454.5; and
3. Develop or refine procurement rules that were not resolved in R.10-06-005, and consider other emerging procurement policy topics.

The Scoping Memo, along with a Revised Scoping Memo issued May 21, 2013, divided the proceeding into four Tracks:

1. Track 1 was the "Local Reliability" track. This track

concluded with Decision (D.) 13-02-015.

2. Track 2 was the "System Reliability" track. D.12-12-010 was issued in this track adopting scenarios for analyzing system reliability. A Ruling issued September 16, 2013 cancelled Track 2 and deferred such issues to the next long-term procurement plans proceeding (LTPP) Rulemaking.
3. Track 3 is the "Procurement Rules and Bundled Procurement Plans" track. This is the decision regarding procurement rules as part of Track 3 in this proceeding. The Revised Scoping Memo did not set a schedule for filing of bundled procurement plans.
4. Track 4 is the "San Onofre Nuclear Generating Station (SONGS)" track. Track 4 will consider the local reliability impacts of a long-term outage at SONGS generators, which are no longer operational. The Revised Scoping Memo set a schedule for this track.

The Commission maintains a Procurement Policy Manual[1] which provides all of the requirements and guidance provided by the Commission to its jurisdictional entities under Public Utilities Code Sections[2] 380, 454.5, and 399.11-399.20.[3] AB 57 was codified as Section 454.5, which sets forth the statutory framework for Commission review of utility procurement plans. Section 454.5 requires that the IOUs prepare procurement plans for review and approval by the Commission and ensures that all costs associated with transactions executed by an IOU in accordance with its Commission-approved procurement plan will be fully recoverable. Procurement plans are generally prepared every other year following the adoption of official load forecasts by the California Energy Commission (CEC) in its biennial Integrated Energy Planning Report process.

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[1] This document (also known as the Rulebook) can be found on the Commission's website.

[2] All Code Section references are to the Public Utilities Code, unless otherwise noted.

[3] The Procurement Policy Manual was most recently updated on June 2, 2010.

Section 454.5(b) sets forth the elements which an electrical corporation's proposed procurement plan for its bundled customers must include. Section 454.5(d) sets forth the requirements for the commission to review and accept, modify, or reject each electrical corporation's bundled procurement plan.

Since the Procurement Policy Manual was last updated in 2010, D.12-04-046 (in R.10-05-006,the 2010 long-term procurement plans (LTPP) proceeding) further addressed rules issues, including: procurement rules relating to power plants using once-through cooling; a proposal from Southern California Edison for a new generation auction; refinements to evaluating bids where utility-owned generation and independent generation are competing; utility procurement of greenhouse gas related products; a request from the Independent Energy Producers relating to generator recovery of greenhouse gas compliance costs; and general procurement oversight rules.

The Scoping Memo in this proceeding at 11 set forth the following expectation for Track 3 of this proceeding:

> There will be two portions of Track 3. First we will consider what changes should be made to current procurement rules, as well as what new procurement rules should be adopted. Second, and after a decision on procurement rules, we will require the IOUs to file bundled procurement plans.[4]

This decision involves the first portion of Track 3, regarding procurement rules. A March 21, 2013 Ruling set forth a series of questions regarding Track 3 rules issues for parties to comment upon. The questions are delineated in sections of this decision. Parties filed comments on Track 3 rules issues on April 12, 2013. Parties filed replies to comments on April 26, 2013.

The parties which filed comments in Track 3 of this proceeding are: AES Southland (AES); Alliance for Retail Energy Markets and, Direct Access Customer Coalition (AReM/DACC); California Energy Storage Alliance (CESA);

[4] Bundled procurement plans will be next considered in the 2014 LTPP proceeding.

California Environmental Justice Alliance (CEJA); Calpine Corporation (Calpine); City and County of San Francisco (CCSF); Clean Coalition; Competitive Power Ventures, Power Development Inc. (CPV); Division of Ratepayer Advocates (now Office of Ratepayer Advocates or ORA); Green Power Institute (GPI); Independent Energy Producers Association (IEP); Marin Energy Authority (MEA); NRG Energy (NRG); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Shell Energy North America (US), L.P. (Shell); Sierra Club California (Sierra Club); Southern California Edison Company (SCE); South San Joaquin Irrigation District (SSJID); TAS Energy (TAS); The Utility Reform Network (TURN); and Western Power Trading Forum (WPTF); Women's Energy Matters (WEM).

3. PG&E September 20, 2012 Motion

On September 20, 2012, PG&E filed a Motion to move the Track 3 multi-year procurement issue to the RA proceeding. PG&E argues that there appears to be an emerging consensus among the parties that participate in the various procurement-related proceedings at the Commission that the current, one year forward RA program should be improved in at least two respects. First, PG&E maintains that the RA program should take into account the need for some level of resource "flexibility" in order for the system to be operated reliably. Second, PG&E argues that the current, one-year forward RA procurement requirement applicable to all load serving entities should be extended to a multi-year timeframe, as the ISO has expressed that the current one-year forward requirement does not provide it with adequate assurances that the resources needed to operate the system will be available.

PG&E notes that flexibility is being addressed in the RA proceeding and the multi-year procurement requirement is currently slated to be addressed in Track 3 of this proceeding. PG&E requests that the two issues be considered together in the RA proceeding where efforts are already underway to address flexibility. PG&E asserts that these two topics are too closely related to be separated artificially, and the consolidated approach will increase administrative efficiency, both for the Commission and for the interested parties. PG&E also requests that all Track 3 issues be deferred to after the completion of Track 2. On October 5, 2012, several parties responded to PG&E's Motion, both in favor and opposed to all or part.

We will deny PG&E's Motion. We deny as moot PG&E's request to defer all Track 3 issues until after Track 2 is complete, because Track 2 was cancelled per a September 16, 2013 Ruling. Instead, we will address the limited subset of Track 3 issues which were encompassed by the March 21, 2013 Ruling. We will not consider flexibility issues or multi-year contracting issues in this decision. A recent RA decision (D.13-06-024) adopted an interim definition of flexibility. Further issues regarding flexibility for RA purposes will continue to be addressed in the RA proceeding, R.11-10-023 or its successor. We also will not address multi-year contracting issues in this decision; the Commission at its November 14, 2013 meeting indicated these issues would be considered in a separate Rulemaking.

4. Maximum and minimum limits on IOU forward purchasing of energy, capacity, fuel, and hedges

4.1. Question:

Should the Commission modify the AB 57 bundled procurement guidelines to indicate minimum and maximum limits for which the three IOUs must procure for future years? If so, should these minimum and maximum limits address energy, system RA, local RA, and/or flexibility?

4.1.1. Current Rule

Ordering Paragraph 1 of D.12-01-033 approved the IOUs 2010 bundled procurement plans. Ordering Paragraph 2 of that decision stated: "Approval of PG&E's and SDG&E's bundled procurement plans includes the incorporation of position limits and maximum rates of transactions, as proposed by the companies in their comments on the Proposed Decision." The approach adopted by the decision is spelled out at. 14-15:

> PG&E and SDG&E, however, propose (in almost identical language) an alternative approach, under which they would use an approach based on that of SCE:
>
> > PG&E [SDG&E] is willing to modify its BPP in order to establish position limits similar to those of SCE. Specifically, the portion of SCE's methodology that PG&E [SDG&E] is willing to adopt is contained in Section 3 (Procurement Limits and Ratable Rates) of SCE's proposed 2012 bundled plan. PG&E [SDG&E] proposes to follow the methodology set forth in subsection (b) of Section 3, which applies to bundled system capacity procurement, and subsection (f), which applies to transaction compliance accounting and limit updates. PG&E [SDG&E] would adopt these aspects of SCE's bundled plan and apply them to PG&E's [SDG&E's] bundled procurement in the same manner as detailed in SCE's bundled plan. [Citations deleted]
>
> > This proposed approach provides additional protection to ratepayers, and allows us to find that the utilities' proposed bundled procurement plans, as modified by this decision, are reasonable under § 454.5. Accordingly, we adopt the alternative approach proposed by PG&E and SDG&E, modeled on SCE's bundled procurement plan, rather than the cost cap approach set forth in the Proposed Decision.

4.1.2. Parties' Positions

PG&E supports procurement limits on electricity and natural gas purchases for its electric portfolio, RA, and greenhouse gas (GHG) compliance instruments, including position and execution limits, but recommends that minimum limits for positions and executions be set only to the extent the Commission desires a minimum level of hedging to manage bundled customer risk. PG&E claims it is premature to consider minimum and maximum limits for flexible capacity, or to meet the one-year-ahead system RA requirement.

SCE recommends that the Commission not modify the guidelines. SDG&E states that minimum and maximum procurement limits for energy products are already addressed in SDG&E's bundled plan.

IEP recommends the Commission adopt guidelines to provide the IOUs with the authority to procure resources needed to meet procurement targets and ensure grid reliability. Calpine and NRG believe that all load serving entities should be subject to mandatory multi-year forward procurement requirements. WPTF contends the issue of forward market procurement requirements needs to be addressed both here and in the RA docket, R.11-10-023. WPTF supports both the implementation of a multi-year forward capacity obligation for all load serving entities (LSEs) and the implementation of a centralized capacity market.

AReM/DACC argues that the Commission should establish minimum limits for IOU procurement to comply with the requirements of AB 57 to procure energy, capacity and reserves sufficient to serve their bundled loads over the long term.

ORA believes the Commission should not establish a minimum limit for forward procurement in the absence of an adequate record and stakeholder process for developing the limit and allocating costs. TURN is concerned that imposing minimum and maximum limits for procuring any particular electric product or service could increase IOU costs for serving bundled customers.

Sierra Club contends the Commission should establish maximum limits for the purchase of fossil fuel resources, which should be established to implement the loading order and minimize the use of fossil fuels. CEJA offers that the Commission should include limits on forward purchasing of energy and capacity because forward purchasing of GHG compliance instruments is not a reliable way to meet the goals of AB 32 and does not safeguard ratepayers. WEM suggests that the rules for bundled procurement should limit new fossil-fueled resources to zero, except for combine heat and power (CHP) and potentially the repowering of OTC plants.

4.1.3. Discussion

We will not establish new minimum or maximum procurement levels for bundled procurement plans at this time.

The three IOUs all correctly point out that minimum and maximum procurement limits are already addressed in their bundled procurement plans. The current bundled procurement plan framework, under the Procurement Policy Manual rules established pursuant to AB 57 (as most recently updated by D.12-04-046), provides adequate assurance that the IOUs will not procure any products in excess of the forecasted need, and will not procure any products to reduce portfolio risk if such procurement is inconsistent with the Commission-approved Customer Risk Tolerance level. IOU procurement of authorized energy, natural gas, emissions and financial hedging products is restricted by predetermined volume limits and transaction rate limits approved in the bundled procurement plan, based on a forecast of future procurement needs. In effect, the bundled procurement plan already provides an upper limit on procurement.

Parties such as Sierra Club call for maximum procurement levels for fossil-fuel resources or minimum procurement levels for preferred resources. We are committed to goals related to GHG reduction and to the Loading Order prioritization of preferred resources (energy efficiency, demand response and renewable resources) over fossil-fuel resources. There are a number of proceedings which seek to implement statutes, policies and goals in these important areas. In the 2006 LTPP proceeding, D.07-12-052 at 3-4 stated:

> Going forward the utilities will be required to reflect in the design of their request for offers (RFO) compliance with the preferred loading order and with GHG reduction goals and demonstrate how each application for fossil generation comports with these goals… (W)e will require that subsequent LTPP filings for our regulated utilities not only conform to the energy and environmental policies in place, but aim for even

> higher levels of performance. We expect the utilities to show a commitment to not only meet the targets set by the Legislature and this Commission but to try on their own to integrate research and technology to strive to improve the environment, without compromising reliability or our obligation to ratepayers.

We reiterate this exhortation to the utilities and continue to expect every reasonable effort to meet or exceed environmental goals, consistent with reliability and cost. Section 454.5(b)(9) requires "a showing that the procurement plan will fulfill its unmet resource needs from eligible renewable energy resources in an amount sufficient to meet its procurement requirements pursuant to the California Renewables Portfolio Standard Program" and "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible." This obligation is ongoing.

In a 2010 LTPP decision (D.12-01-033 at 20) on bundled procurement plans, we states that "the utility obligation to follow the loading order is ongoing…even if pre-set targets for certain preferred resources have been achieved." However, in that decision at 21-22, we stated that this obligation was limited to preferred resources that are "feasibly achieved and cost effective." Similarly, in the Track 1 decision (D.13-02-015) in this proceeding, we strove to meet the objectives of Section 454.5(b)(9) while also maintaining reliability and reasonable rates. In that decision, we authorized procurement of significant levels of preferred resources (and energy storage resources), along with minimum and maximum level of fossil-fuel resources to meet local reliability needs.

We will not establish additional rules for a maximum level for fossil-fuel resources. We take ORA's point that, while there are potential benefits of mandating minimum procurement limits, the record in this proceeding is inadequate to ensure that bundled customers would not bear a disproportionate share of reliability costs. Instead we will continue to implement and balance Commission environmental, reliability and rate requirements consistent with specific needs in each bundled procurement plan, while ensuring Section 454.5(b)(9) is followed. We will also not establish minimum procurement levels for preferred (or any other) resources in this proceeding, but will review the upcoming bundled procurement plans to ensure they continue to incorporate other relevant Commission environmental directives from other proceedings.

Minimum procurement levels are already established in the RA proceeding, as shown in Rule RA.2. All Commission-jurisdictional LSEs are required to demonstrate procurement of 90% of their next year's system RA requirement and 100% of their next year's local RA requirement on a year-ahead basis, as well as 100% of their system RA requirement on a month-ahead basis. Further, per Rule G.1(c), LSEs are not to rely, on a planning basis, on the spot market for more than 5% of their energy purchase requirement (with specified exceptions). In addition, we agree with SCE that if the market is aware that the IOU has an additional minimum procurement obligation, counterparties may have an incentive to raise their prices as the IOU is required to purchase to certain levels. We agree with TURN that additional minimum procurement requirements for any particular electric product or service could increase ratepayer costs. At this time, we see no corresponding or overriding benefit to further minimum procurement requirements.

Issues regarding centralized capacity markets are not within the scope of this proceeding. Similarly, we will not consider multi-year forward contracting here. Issues regarding limits on flexible capacity are encompassed in the RA proceeding.

4.2. Question:

How may the Commission best balance issues regarding departing load in any future requirements for procurement?

4.2.1. Current Rule

Regarding procurement planning, Ordering Paragraph 8 of D.12-01-033 states: "Southern California Edison Company is authorized to use its proposed direct access assumptions, and the other utilities should procure consistently with those assumptions." That decision at 30 explains further:

> SCE includes in its forecast the maximum allowable phase-in of new direct access sales permitted under Senate Bill (SB) 695, which are greater than under the Standardized Planning Assumptions. Specifically, SCE forecasts that the Commission-authorized increase in direct access would be fully subscribed in each year until 2013, consistent with D.10-03-022. SCE argues that their assumptions are more consistent with SB 695 and D.10-03-022 than the standardized planning assumptions.
>
> We agree with MEA and SCE on this issue. It is appropriate to use more accurate load forecasts for MEA, consistent with SB 695, instead of the load forecast in the standardized planning assumptions. SCE is authorized to use its direct access assumptions for purposes of establishing position limits and ratable rates for its bundled procurement plan. The other utilities should engage in procurement consistent with SCE's assumptions for direct access. (*footnotes and references omitted*)

4.2.2 Parties' Positions

PG&E notes that each IOU's bundled procurement plan incorporates departing load forecasts and there is no need for additional Commission action on this issue. SCE agrees that its forecast of the future need to procure energy products reasonably accounts for departing load. SDG&E suggests that departing load issues associated with multi-year forward procurement requirements should be addressed in the ongoing RA proceeding.

IEP recommends establishing clear rules and procedures to explain how costs associated with IOU procurement follow departing load. WPTF believes the Commission should clarify that the IOUs are to plan for reasonable amounts of departing load and then only procure for the assumed amounts of retained bundled load.

AReM/DACC recommends that the IOUs should be required to estimate reasonable levels of expected DA (Direct Access)/Community Choice Aggregators (CCA) departing load over the 10-year term of the bundled plans and should then exclude this load from their future resource plans and procurement activities. Having been excluded from the planning scenarios, the forecasted departing DA and CCA load would not be subject to any non-bypassable charges, either stranded costs or cost allocation methodology (CAM), for procurement costs incurred by the IOUs after approval of the bundled plans.

SSJID states that the Commission requires IOUs to use reasonable assessments of future conditions, rather than the most conservative assessments, when faced with load and supply uncertainty in their procurement forecasts. Thus, SSJID concludes that PG&E should not procure capacity on behalf of SSJID because SSJID is in the process of undertaking to provide retail electric service within its existing service area. Specifically, SSJID contends it would be unreasonable and imprudent for PG&E not to account for SSJID's planned municipalization in its departing load forecasts.

MEA believes the Commission should direct the IOUs to incorporate reasonable estimates for CCA departing load in their bundled procurement plans. The IOU procurement plan should be evaluated, in part, on its resilience to varying levels of departing load without creation of stranded costs. Sierra Club recommends that the bundled plans should plan and account for a certain amount of departing load. WEM argues that the Commission should develop policies that move the utilities out of the way of others providing what customers want, or push the utilities more effectively towards revising their business models in these directions.

4.2.3. Discussion

We agree with the concept expressed by most parties that the IOUs should plan for reasonable amounts of departing load in their bundled plans and then only procure for the assumed amounts of retained bundled load. We also agree that the IOUs do, at this time, appear to take into account their expectations for departing load in their forecasts. There appears to be a dispute between PG&E and SSJID as to whether PG&E accurately accounts for departing load in their forecasts.

It is appropriate to give guidance here to clarify the IOU's obligations with regard to forecasting departing load as part of the bundled forecast. It is possible that there is a difference between the IOU's calculation of departing load and other objective measures of departing load, even after our decision in D.12-01-033. We require the IOUs, with information provided by the CEC and from other sources, to estimate reasonable levels of expected DA and CCA departing load over the 10-year term of the bundled plans. For CCAs specifically, the Commission has adopted an Open Season and Binding Notice of Intent (BNI) process to trigger the exclusion of potential CCA load from IOU bundled procurement. *See*, D.04-12-048, at 53-55 and Findings of Fact 27-29, at 201-202; D.0512-041, at 30-36 and Attachment B, as modified by D.06-02-006. Once a CCA has submitted a BNI, its customers are no longer responsible for utility bundled procurement costs incurred after that date.

The IOUs should exclude this forecasted departing load from their future procurement activities, and only procure for the assumed amounts of retained bundled load. Having been excluded from the bundled portfolio planning scenarios, the forecasted departing DA and CCA load would not be subject to non-bypassable charges for any incremental stranded procurement costs incurred by the IOUs for the period after the date of departure assumed in their approved bundled plans.

Specific disputes, such as that raised by SSJID, can be litigated when an IOU files its bundled procurement plan, which will occur in the next LTPP proceeding.

5. Impacts of transparency on forward procurement

5.1. Question:

Should the Commission require the three major electric IOUs to provide more public transparency into the levels of future procurement for which each has entered into a contract? What confidentiality rules could be changed or removed? In particular how can IOUs provide visibility to the California Independent System Operator (CAISO) regarding their midterm procurement contracts?

5.1.1. Current Rules

The current rules governing confidential treatment of IOU data are set forth in D.06-06-066. Appendices 1 and 2 to D.06-06-066 provide rules for determining the confidential or public treatment for different types of utility and energy service provided (ESP) procurement information.[5] With regards bilateral or RFO-based procurement information, section VII subsections A and B specify treatment of information in contracts with affiliates and with non-affiliate market parties, respectively. Generally, pricing and contractual terms and conditions are confidential for three years. Other information such as identity of counterparty, location and name of generating facility involved, and megawatt (MW) size and length of contract (term in months or years) is public immediately. Pricing and market sensitive terms and conditions of contracts become public three years after first delivery under the contract.[6]

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[5] D.06-06-066 is linked here: http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/57774.PDF

[6] Some fields in the matrix were modified by D.08-04-023, but not the two discussed in this section.

5.1.2. Parties' Positions

SDG&E and PG&E contend the question of whether confidentiality rules adopted in D.06-06-066 should be changed or removed is outside the scope of this proceeding. SCE does not support changing the Commission's current confidentiality rules, because they provide a sufficient level of transparency to the public and can adequately provide visibility to the CAISO.

IEP recommends that the IOUs clearly define the product they are seeking and should provide information about how certain characteristics of the product (or the developer, for some bid elements like viability or security) will be weighed in the evaluation process. IEP maintains that greater transparency about the prices of completed procurement will provide the market with the information it needs to respond to surplus (reflected in low prices) or scarcity (reflected in high prices).

Calpine believes information sharing regarding the IOUs' forward procurement plans is necessary but not sufficient to address the CAISO's intermediate-term reliability concerns. One function of a capacity market or other formal forward procurement obligation would be for the CAISO to validate forward procurement (*i.e.*, not only receive information about IOU procurement but ensure that the associated resources have tariff and/or regulatory obligations to be available and satisfy performance requirements).

WPTF concurs that greater transparency is needed with regard to the levels of future procurement for which each IOU has entered into contracts. WPTF believes such transparency, including in RFOs, will provide clearer signals to the market with regard to future planning and will enable prospective suppliers to better focus their future bid activities.

CCSF opines that the forward procurement process requires more transparency so that CCAs and ESPs can accurately assess the capacity and costs that will be assigned to their customers from past purchases. MEA encourages increased transparency in the IOUs' procurement. MEA states that its procurement information is publicly available and transparent, and the Commission should require that IOU procurement be similarly publicly available and non-confidential.

ORA believes the Commission should not require the IOUs to provide more public transparency regarding the levels of future procurement for which each has entered into a contract. ORA suggests the Commission pursue increased transparency by providing aggregated procurement data based on information gathered in the quarterly compliance reports, but not change or remove any existing confidentiality rules. ORA supports providing the CAISO with access to confidential information relating to the contract terms, pricing, and conditions of the IOUs' electric short, medium, and long-term procurement.

TURN agrees with the goal of providing the public more transparency as to the levels of future procurement. One step TURN suggests now is to aggregate the IOUs' procurement data along with those of other LSEs – to the extent they are knowable – and make this aggregated information public to the extent possible. TURN believes California would benefit greatly if the CAISO had more information about the IOUs' mid-term procurement activities and positions, particularly relating to those contracts that provide financial support to existing capacity.

Sierra Club believes agencies with regulatory obligations with respect to IOUs, such as CAISO and the Energy Commission, as well as the public, should have access to significant information about mid-term and other procurement contracts. CEJA urges the Commission to require further transparency within the procurement process to ensure the ability for meaningful public participation by communities affected by procurement. CEJA requests that the Commission require the disclosure of all non-confidential information submitted to the Procurement Review Group (PRG) to inform the public about RFO solicitations and evaluations. CEJA urges the Commission to increase transparency by making the environmental evaluation of projects in the RFO process publicly available, and to mandate disclosure of all bid evaluation criteria.

Clean Coalition supports the Commission's presumption that that information should be publicly disclosed. All pricing information for all power purchase agreements (PPAs) should be transparent to serve the interests of ratepayers. WEM feels that the most urgent need is for the Commission to pry open the utilities' near-absolute secrecy in regard to the distribution system, because almost all of the "distributed" preferred resources are attached to that system rather than transmission.

5.2. Question:

How can bids and offers RFOs are released publically? What other information could be released?

5.2.1. Current Rule

The current rules governing confidential treatment of IOU data are set forth in D.06-06-066. Appendices 1 and 2 to D.06-06-066 provide rules for determining the confidential or public treatment for different types of utility and ESP procurement information. Section VIII deals with the bid and valuation data produced by utilities and bidders in utility solicitations for capacity and energy. Bid data as well as other quantitative data of offer valuation is confidential for three years after the final winning bid is chosen and the contract is final.

5.2.2 Parties' Positions

PG&E does not believe disclosure of RFO bidding and pricing information is in the best interest of customers. PG&E believes the current amount of disclosure regarding RFO offers strikes the appropriate balance and no additional rules need to be adopted. SCE claims that bids and offers into RFOs are market-sensitive procurement information that is specifically protected under the IOU Confidentiality Matrix and therefore the Commission should not require it to be disclosed. SDG&E contends that the Commission had previously found that it is statutorily obligated to protect RFO bid data from disclosure.

IEP recommends that bids and offers submitted in IOU RFOs should be treated as confidential data to increase the level of competition and to promote innovation. Calpine opines that information should be made available so that market participants could replicate the market valuation and other components of the analysis and ranking of offers that the IOUs perform in their solicitations.

WPTF suggests that winning bid/offer information could be released five years after the fact on an anonymous basis that conceals the identification of the successful bidders. CCSF favors release of information to stakeholders about bids and offers into request for offers.

ORA recommends that bids and offers into RFOs should not be released publicly as the disclosure of bids and offers could negatively affect negotiations between the IOUs and power suppliers to the detriment of ratepayers.
Sierra Club recommends that this information be made public on the Commission website. The data should include bids, offers, price, volume, location, and date of delivery. Clean Coalition agrees that bids and offers into RFOs should be released online.

5.2.3 Discussion of Questions 5.1 and 5.2

The two preceding questions sought stakeholder input regarding whether to provide greater information to stakeholders, market participants, and other interested parties in California regarding utility procurement policies, recent procurement activities, and pricing and bid information. There appears to be two different types of information that are the subject of stakeholder interest: Utility procurement information, conducted either via bilateral negotiations or RFOs, and market participant bids and final contracts with pricing information or other terms and conditions that are market sensitive.

Section 454.5 (g) states:

> The commission shall adopt appropriate procedures to ensure the confidentiality of any market sensitive information submitted in an electrical corporation's proposed procurement plan or resulting from or related to its approved procurement plan, including, but not limited to, proposed or executed power purchase agreements, data request responses, or consultant reports, or any combination, provided that the Office of Ratepayer Advocates and other consumer groups that are nonmarket participants shall be provided access to this information under confidentiality procedures authorized by the commission.

The Commission has not to date allowed public disclosure of RFO bid and offer information, as such disclosure could reasonably be expected to affect the market to the detriment of IOUs and their ratepayers. Nothing has changed in this regard. We do not find it to be in the public interest to provide disclosure at this time. Certain providers of or advocates for preferred resources appear to believe they could benefit from disclosure of bid and offer (and other related) information, which may provide some advantage for such resources. The Commission has a number of policies in place and statutory requirements which provide avenues for additional preferred resources. It is more appropriate to pursue policies in these ways than to disrupt market functions through disclosure of currently confidential information.

Careful thought is required to balance the interest of market sensitivity of certain pricing and contractual terms between the utilities and their counterparties, with the benefits of increased transparency for market forecasting and procurement oversight. The market will benefit from greater reporting of procurement activity, particularly in the forward time frame where it is currently less open to the public.

The CAISO will also benefit from greater reporting of procurement information. The CAISO, as the entity responsible for ensuring reliable grid operation, must plan around which generating resources will be available to them and how those resources might operate. In the absence of contracts, there is reasonable uncertainty about which generating resources will continue to be operating and in what capacity within the energy market. The market behavior of individual generating facilities impacts planned operation of other facilities; information regarding which facilities were contracted (and which were not) is of importance to planning for grid operations in future years.

Therefore we intend to promote greater reporting of the information that the Commission regularly collects from the utilities, either as aggregate or in specific when advisable. As discussed at the November 14, 2013 Commission meeting, we intend to address issues related to providing the CAISO with access to certain utility contracting information in a related Rulemaking (the "Joint Reliability Plan" Rulemaking). Below in this decision we articulate a plan to reform certain data requesting guidelines, with an eye towards aggregating data via the quarterly compliance reports (QCRs) and reporting out that data in ways that are consistent and usable, while protecting market sensitive information.

In addition, the Commission is concerned that the non-disclosure agreements that the IOUs require bidders in their RFOs to sign have impeded the ability of market participants to bring concerns regarding the conduct of RFOs to the attention of the Commission and other state officials. While this Commission has no desire to be drawn into commercial negotiations regarding the prices and specific contractual terms and conditions being discussed between the IOUs and potential contractual partners, it is not in the public interest for parties participating in RFOs to be precluded from bringing more general concerns about the conduct of an ongoing or past RFO to the attention of the commission. Therefore, any non-disclosure agreement that the utility requires an RFO participant to sign must not bar the participant from reporting such concerns, nor may a utility arbitrarily reject the offer of a participant that engages in such a discussion with appropriate officials.

6. Long-term contract solicitation rules

6.1. Question:

Should the Commission adopt a rule that explicitly indicates that existing power plants may bid upgrades or repowers into new-generation RFOs?

6.1.1. Parties' Positions

PG&E states that RFOs for new generation (typically referred to as Long-Term RFOs) are generally designed to meet an incremental need for new system, local or flexible capacity. PG&E's position is that limitations regarding past long-term RFOs (only for new or repowered resources that are capable of addressing the incremental need) should remain in place, but existing facilities (including upgrades to existing facilities) should continue to be considered in short-term or intermediate-term solicitations. However, PG&E cautions that allowing existing resources to compete in new-generation long-term RFOs may lead to over-procurement, increased costs for customers, higher emissions, and/or a failure to meet the needs of the RFO.

SCE recommends that the Commission only allow capacity (whether developed at an existing power plant site or at a new site) that is incremental to what was assumed in the underlying "need determination" analysis to compete in "new generation" RFOs, so long as such incremental MW can provide the necessary attributes that the Commission has authorized the utility to procure. SDG&E does not object to allowing existing facilities to bid upgrades or repowers into new-generation RFOs. An existing facility may provide value to IOU ratepayers if it: (i) has a useful life extending beyond its current contract; or (ii) is able to lengthen its useful life by upgrading or repowering various facility components. SDG&E recommends that the Commission make clear that allowing upgrades or repowers to bid into new-generation RFOs does not change or override any additional requirements in an RFO such as locational requirements or operational characteristics.

IEP believes that distinctions among generating units based on age or vintage, or new vs. repower, are unnecessary in a product-oriented energy market. IEP recommends that if existing generators and repowers are excluded from bidding in long-term procurement solicitations, then a reasonable short- or medium-term capacity market (*e.g.*, 3-5 years) should be made available to these projects. Calpine recommends that the Commission reform long-term procurement rules to eliminate discrimination between different vintages of capacity. In addition, long-term procurement should focus on homogeneous products with uniform terms (*e.g.*, generic, local, or flexible capacity for 10-year terms).

AES Southland calls for the Commission to ensure that any upgrades or repowers that are bid into new generation RFOs result in additional incremental generation. AES Southland proposes that a generation project not be permitted to bid into a new generation RFO if that generation appears on the CEC's current California Power Plants Database of existing, operating plants in California as of the date of the RFO, except to the extent that the repower or upgrade would provide significant incremental capacity to the CAISO balancing authority area, either by expanding the generation capacity at a generation facility, or by extending the useful life of a generation facility, as a result of significant capital investment.

TAS Energy recommends adapting existing utility procurement rules to allow for retrofits including additions of energy storage systems to existing power plants by means of competitive procurement process such as requests for offers and bilateral contracts. CPV calls for IOU solicitations to be open to both existing and new generation to ensure that the broadest range of projects are afforded available commercial opportunities. The term of the contract should be commensurate with the needs of IOU but should also be influenced by the type of facility. An upgraded facility might only be eligible for a shorter duration contract relative to a repowered facility, while a new facility should be offered a longer term contract.

WPTF believes upgrades and repowers should be allowed to compete, just as any other way of meeting the RFO issuer's need should be permitted to participate. However, WPTF opposes the underlying implicit concept in the question that suggests that the utilities should conduct "new generation" RFOs. Rather, utilities should be required to issue RFOs for a need, whether that need is capacity, energy, ramping capability, location or a combination of some or all of these products. Any entity that can meet the need(s), as specified, should be allowed to bid.

ORA recommends that the Commission explicitly allow existing power plants to bid upgrades of those resources into new resource RFOs, providing that the quantity being offered is incremental to the existing rated capacity of the resource. TURN also recommends that the Commission should facilitate the IOU competitive contracting for upgrades or repowers of existing power plants.

Sierra Club recommends that the Commission make a distinction between a long-term repower and an upgrade that may provide a relatively short-term capacity fix while California transitions to low carbon future. CEJA urges the Commission to adopt a rule that explicitly indicates that existing power plants may bid upgrades or repowers into new-generation RFOs. GPI suggests the Commission's singular goal in this particular kind of solicitation should be in procuring the lowest-cost energy possible. This means that the offers need to be refocused from their present orientation to the machinery that produces the needed product, to instead focus squarely on the needed products themselves, regardless of how they are produced.

6.1.2. Discussion

Most parties recommend that the Commission allow certain upgrades and repowers to bid into long-term RFOs. While current rules do not specifically prohibit the combination of RFOs for existing or new facilities, we hereby clarify that certain upgraded and repowered plants are allowed to bid in new generation RFOs. We clarify the rules so as to oversee the administration of RFOs that fill defined reliability needs in the most cost effective way.

Allowing for the incremental capacity of existing plants or repowered plants to participate in long-term RFOs appropriately acknowledges the varied technological capabilities and improvements possible with today's generation stock, and may alleviate some need to build additional capacity. In addition, it may be possible for an existing power plant to add capabilities (*e.g.*, energy storage, more optimal ramp rate, or start up times) that would enhance the operation of the plant and increase its value to the system.

In discussing this issue, first we need to define the term "incremental capacity." We will take SCE's recommendation that the definition should be "capacity incremental to what was assumed in the underlying needs assessment." In other words, these are net additions. We agree with SDG&E that an existing facility may provide value to IOU ratepayers if it has a useful life extending beyond its current contract or is able to lengthen its useful life by upgrading or repowering various facility components. The following terms are defined herein:

- <u>Upgraded plants</u>: Upgrades are defined as expanding the generation capacity at, or enhancing the operation of, a generation facility, so long as such incremental MW can provide the necessary attributes that the Commission has authorized the utility to procure. An upgraded plant or a plant with incremental capacity additions would be a plant where the main generating equipment is retained and continues to operate.
- <u>Repowered plants</u>: Repowers are defined as capital investments that extend the useful life of a generation facility, after the planned retirement date. A repowered facility is a facility where the main generating equipment

(such as the turbine) is changed out for new equipment.

Parties want to ensure neutrality between types of facilities that are competing against one another in a solicitation for capacity. Some parties doubt that utilities define capacity needs specifically enough to ensure that valuations can be neutral with regards whether the offered product meets the identified needs. We urge the utilities to remove whatever ambiguity or lack of clarity there is in RFO documents, so as to ensure that bidders know which services, quantities, or locations are the target of the RFO. While we are unaware of specific examples in this proceeding of RFOs that cause bias towards or against a type or vintage of facility through lack of clarity in bidding documents or bid valuations, parties are encouraged to bring complaints to the attention of Energy Division for investigation.

6.2. Question:

How should the existing and upgraded components of the repowers be valued differently in an RFO? How can additions such as energy storage be added to existing facilities and be valued against other types of offers?

6.2.1 Parties' Positions

PG&E suggests the same principle should apply to energy storage that is incorporated into repowers and upgrades of existing facilities. If the storage technology results in a facility with a remaining useful life equivalent to a new resource, it should be eligible to compete through a long-term RFO. SCE recommends that only the net additions to what was assumed in the underlying need determination analysis would be eligible to be counted towards meeting the identified need. Once the generation is found to be eligible to participate in the new generation RFO, SCE plans to apply the same valuation and selection methodology to all eligible generation that can fill the identified need (*i.e.*, provides the necessary attributes that SCE is seeking via its new generation RFO). SCE plans to value any energy storage additions proposed at existing facilities in a similar manner to all other new resources that it procures. SDG&E comments that upgrades and repower proposals do create some complexity in the evaluation, but the product they provide should be valued no differently than any other offer.

IEP believes the answer to the question depends on if the Commission develops a product-oriented procurement model to disaggregate the cost basis of unit bids. Competition among those that can provide the products or services requested will reveal the value in the first case, whereas the second case requires a much broader discussion. The simplest and most useful tool for determining the benefit associated with energy storage is to have transparent, time-of-delivery factors applied in bid evaluation so that bids are valued based on their ability to deliver (or absorb) energy when needed and subject their facilities to economic dispatch. Calpine recommends that the existing and upgraded components of a facility not be treated differently in long-term solicitations.

AES Southland suggests that the Commission should not use different evaluation methodologies for determining the value of existing versus upgraded components of repowers in an RFO. Instead, it should strive to develop a generally applicable set of bid evaluation metrics that would allow the utilities, and the Commission, to quantify the benefits of upgraded or repowered generation as compared to new generation. Like upgrades and repowers, storage additions should be evaluated pursuant to a general set of evaluation metrics that would allow the Commission and utilities to compare the benefits of storage additions to other solutions to energy and capacity needs.

TAS Energy recommends that, as these cost savings would be reflected in the bid, retrofits should be valued comparably with other resources accordingly. In the case that the retrofit is an energy storage system, it would be consistent with other proceedings and determinations for this system to be evaluated along with other cost-effective preferred resources including energy storage resources.

CPV recommends that the attributes and associated cost of the aggregate generation (rather than its components) should be the driver in the RFO, and evaluation of storage should be no different than that of generation.

CESA recommends developing a means to transparently value the addition of storage to existing generation facilities, by measuring the value of adding capacity or economic value via competitive procurement process such as requests for offers or bilateral negotiations. CESA states that it is imperative to ensure that additions and retrofits are able to participate in the RFO process are explicitly stated to be eligible be included in RFO's, and that power plants then currently under contract would not have their existing contract reopened to account for the new investment in additions or retrofits to the power plant. Rather, a separate overlay contract could be offered to the entity bidding the addition or retrofit project for investment, separately from the existing power plant's existing contract or contracts.

WPTF contends this question confuses need with the method of meeting the need. WPTF believes that repowers should not be valued "differently." Rather, a proposal that includes repowers should be evaluated as to whether or not the proposal does or does not meet the technical needs, as described in the RFO. The same principle should apply with regard to energy storage offers.

ORA notes that resolving issues and developing uniform guidelines for evaluating incremental upgrades would take significant time. ORA in the interim supports providing the IOUs a degree of flexibility to address these evaluation challenges. ORA recommends that energy storage arising from new investment should be valued as a new resource so that it can be bid into a long-term RFO, whether it is located at an existing facility site, or elsewhere.

Sierra Club opines that repowers of fossil fuel plants should not be valued differently, but upgrades should be valued for the role that the upgrades will play in the system. If an upgrade provides short term value that facilitates the opportunity for more preferred resources to be placed on the system, it should be a given a value for this function. Similarly, energy storage should be valued for the additional benefits that it can provide to the system that are not typically valued in the current RFO process, and that are environmentally and operationally superior to the performance of natural gas plants. CEJA recommends that RFOs should allow consideration of energy storage constructed at existing facilities because it can provide additional flexibility and ancillary services.

6.2.2 Discussion

As the responses indicate, this is a complex issue. At this time, we find it to be unnecessary or premature to decide on any new or different valuation for repowers or upgrades in long-term RFOs. In particular, as the energy storage industry develops further, it may be appropriate to develop new valuation rules for such technologies. But we have too little knowledge or information about this fledgling industry to come to any conclusions at this time. However, we do wish to clarify that an offer of incremental capacity should be evaluated based on the cost and value of the incremental capacity alone, and not some combination of the existing and incremental capacity of the unit in question.

6.3 Question:

Should contracts for repowering or upgrading of facilities be restricted to the same length of contracts as new facilities? If not, please explain why there would be different contract lengths or different terms, and how these differences would be reflected in the valuation of the bids.

6.3.1 Parties' Positions

PG&E contends the investment and risk criteria for a retrofit or upgrade to an existing resource is substantially less than for a new or repowered resource. Thus, PG&E believes contracts for existing facilities, including facilities that have incremental upgrades, can be shorter in duration than a contract for a new or repowered resource. SCE plans to apply similar terms and conditions to all eligible generation that can fill the identified need and provide the necessary attributes. SCE does not plan to offer different lengths of contracts to incremental generation as a result of repowering or upgrading of facilities than what it would offer to new facilities. SDG&E recommends that contract term length for repowered or upgraded facilities should be restricted to the remaining useful life of the overall asset.

IEP contends the length of the contract should be determined more by the identified needs of the IOU than by the nature of the offered resources. IEP recommends that bidders of all types, including repowered or upgraded facilities, should have an equal opportunity to bid varying terms of service in response to the IOU's defined needs. Calpine believes that, to the extent that a resource is able to satisfy the defined need, the resource should be able to participate in the resource solicitation regardless of the vintage and/or type of resource.

AES Southland recommends that a repowered or upgraded facility bidding into a new generation RFO should be restricted to the same length of contracts as new facilities. However, AES Southland suggests that RFOs provide a range of minimum and maximum acceptable terms that both new generation and repowered generation could bid into the RFO, and that generation should be permitted to bid more than one term option into the RFO as well. TAS Energy recommends that contracts for repowering or upgrading of facilities should receive the same restrictions and guidance as all other new facilities, with no difference in the length of contract offered. CPV recommends that the IOU's solicitation should specify a minimum and a maximum term into which bidders can exercise their judgment on what makes the most sense for their project.

WPTF does not support narrowly contracting for new resources, repowers or upgrades specifically, but supports the principle that new, repower and upgrade proposals be treated indiscriminately. The Commission can provide clarity by defining contract minimum and maximum terms so that projects can bid in at varying terms with different price structures.

ORA supports flexibility in contract terms that would allow full resource participation and give IOUs the ability to determine which resources best adhere to the least-cost best-fit evaluation criteria. Sierra Club suggests that contracts for upgrades can be for a more limited duration. CEJA opines that contracts for upgraded or repowered facilities should be allowed to bid for different length contracts. GPI states there is no reason to impose different rules or restrictions on facilities just because they are upgrades or repowers of existing facilities.

6.3.2 Discussion

Currently, there are no restrictions on contract lengths for new facilities. We are not convinced that there is any purpose at this time to constrain contract lengths for IOU contracting for upgrades and repowers, as compared to other new resources. Contracts for upgrades or repowers that meet our criteria should be allowed to bid for different lengths of time. The IOU can evaluate such bids based on its needs.

6.4 Question:

Is there any information (additional or subtracted) from the RFO or application templates that would need to be changed? Would Energy Division review the RFO differently?

6.4.1 Parties' Positions

PG&E opines that protocols may need to be changed for future RFOs, and to some degree, application templates. The portions of the protocols that may need to be amended include eligibility requirements and contract options, both of which are dependent on the identified procurement needs for a future solicitation, especially taking into consideration whether the need is longer-term versus short-or intermediate-term. Also, future solicitations should be specific regarding the operational characteristics that a portfolio of procured resources is required to have.

SCE suggests the Commission does not need to change the RFO process or the RFO approval application templates to allow upgrades at existing power plants or repowered sites to compete in new generation RFOs. SDG&E agrees that the RFO application and templates do not require amendment, except to add clear definitions for the following terms: upgrade, repower, and energy storage, and that no change to the Energy Division's current RFO review process is necessary.

IEP suggests that to the extent that a minimum or maximum term of service is desired, the minimum/maximum must be prescribed in the RFO. Additionally, the eligibility requirements for bidders must be clear. AES Southland suggests that the Commission require utilities to develop a robust list of evaluation metrics that should be expressly set forth in each RFO. In turn, those metrics should be evaluated in any application submitting a contract from that RFO to the Commission for approval.

TAS Energy advocates that the RFO process explicitly include a provision that assets currently under contract would not have their existing contract reopened to finance investment in new generation through upgrades to the site. Rather, a separate contract, or overlay contract must be offered to the entity bidding the retrofit/upgrade project for such investment, separately from the existing site's operating contract. CPV recommends greater flexibility as to type of generation and term ought to be added to the RFO process.

6.4.2 Discussion

There is no clear reason to change any aspect of the RFO process or application template at this time as a result of our allowing bids for repowers or upgrades. If any changes become necessary, they can be undertaken through

Energy Division.

6.5 Question:

How should cost allocation issues be addressed?

6.5.1 Parties' Positions

PG&E contends that, to the extent that an upgraded or repowered facility provides system or local benefits, the costs and benefits associated with the facility should be allocated to all benefitting customers (*i.e.,* bundled, DA and CCA). SCE argues that the Commission's current CAM rules should continue to apply to procurement of all new resources authorized by the Commission for system or local area need. SDG&E recommends that if an upgrade or repower of an existing power plant is bid into a new-generation RFO and the Commission determines that the resource is needed to meet local or system area reliability needs for the benefit of all customers in the IOU's service area, the total capacity cost of the repowered or upgraded resource should be allocated to all benefitting customers through the CAM established pursuant to § 365.1(c)(2).

Calpine opines that if suitable forward RA procurement requirements that apply to all LSEs are implemented, then the resulting forward RA market, whether bilateral or centralized, would allocate the cost of forward capacity procurement, regardless of whether the capacity is new, existing, upgraded or repowered. In contrast, to the extent that the IOUs undertake forward procurement on behalf of all customers, not only bundled customers, the cost of such procurement would be recovered through non-bypassable charges.

AReM/DACC recommends that the Commission should insist that the costs of all such upgrades and repowerings are to be recovered solely from the bundled load customers who require these plants to serve their load.

MEA suggests that preexisting facilities which have undergone an upgrade or repower should not be considered for CAM treatment. Sierra Club contends that cost allocation issues should be addressed in a separate proceeding that addresses the costs of all procurement mechanisms at the same time.

6.5.2 Discussion

This decision addresses CAM issues beginning in section 8.

7 Specification of the Rules that, if followed, would allow the IOUs to execute bundled procurement contracts with specified additional review by the Commission[7]

7.3 Question:

Please comment on the following potential new or modified rules to ensure competitive bundled procurement transactions:

1. The IOUs must submit an advice letter or application if they follow their established AB 57 bundled procurement plan authorization, and:
   a. The contract unit price is a higher than a particular percentage (such as 80%) of the CAISO Capacity Procurement Mechanism or other administratively or market established price,
   b. The RFO did not attract sufficient participants, or
   c. The total MW procurement is over a specified level of MW.

7.3.1 Parties' Positions

PG&E contends that rules requiring added review and approval by the Commission would be duplicative, add significant delay to the procurement process, increase procurement costs, and could affect the reliability of the electric system. SCE claims that requiring an advice letter or application, even though an IOU has met its AB 57 bundled procurement plan upfront standards and criteria, would erode that statutory framework. SDG&E claims the proposal violates

AB 57 and is contrary to Commission precedent. SDG&E believes the rules

[7] For clarification purposes, the wording of this section title is slightly different from the wording of the associated question in the Ruling.

currently in place effectively ensure that IOU transactions are reasonable and there is no demonstrated need for the new rules proposed.

MEA does not support these modified rules unless such transactions are excluded from stranded cost treatment; *i.e.*, no costs associated with such transactions would be paid by CCA customers. ORA disagrees with this proposal to reduce the amount of oversight over individual procurement contracts to streamline the contract approval process.

Sierra Club argues that creating mechanisms that reduce the ability of the Commission and the public to review action approved by the Commission reduces the Commission's ability to provide effective oversight. CEJA urges the Commission to not reduce oversight of bundled procurement contracts.

7.3.2 Discussion

Medium-term contracts are contracts of three consecutive months or greater and under five years in duration. Long-term contracts are contracts of five years or more in length. Long-term contracts must be submitted with an application to the Commission for preapproval, whereas short-term and medium-term contracts do not need preapproval. We currently do not impose oversight via advice letters over medium term contracts except for contracts with OTC units. Per D.12-04-046, PPAs with OTC plants with contract duration of greater than two years must be submitted to the Commission's via a Tier III advice letter.

We find there is a gap in Commission oversight. By providing utilities and counterparties with little scrutiny of contracts of significant size with large cost implications, this gap exposes ratepayer to more risk than is appropriate. We conclude that we should impose greater oversight of medium term bilateral contracts. Utilities will now be required to submit Tier II Advice Letters seeking Commission approval to enter into a medium-term bilateral contract if the size of the contract is over 50 megawatts. This rule is in addition to all previous procurement rules._

We also clarify rules for certain multiple contracts. For the purpose of medium term and long term contracts, multiple contracts entered into at the same time for the same resource and for consecutive time periods are considered one contract and may not be treated as different transactions for Commission approval. 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).

D.03-12-062 granted authority for the use of negotiated bilateral contracting in three limited circumstances. One of these circumstances is that an IOU may use negotiated bilateral contracts to purchase longer term non-standard products provided it justifies why a standard product that could have been purchased through a more open and transparent process was not available or in the best interest of ratepayers. The Commission has refrained from broadly defining non-standard products; however, the intent of the Commission and language of Public Utilities Code Section 454.5(B)(5) was to give utilities flexibility in procuring products only in cases where they are difficult to procure via a competitive solicitation. We understand that products like RA capacity and energy tolling are widely available and are not difficult to procure via a competitive solicitation. Therefore, the utilities should treat RA capacity and energy tolling as standard products and reflect this in their AB 57 bundled procurement plans.

7.4 Question:

Should the Commission impose this rule: Any bilateral contract for a facility that did not make the shortlist of an RFO or an offer that has subsequently been negotiating with the utility for longer than six months since making the shortlist of an RFO must seek Commission approval through a Tier III advice letter or application.

7.4.1 Current Rule

D.03-12-062 granted authority for the use of negotiated bilateral contracting in three limited circumstances.

1. For short-term transactions of less than 90 days duration and less than 90 days forward, the IOUs are authorized to continue to use negotiated bilaterals subject to the strong showing standard.
2. Second, utilities may use negotiated bilateral contracts to purchase longer term non-standard products provided they include a statement in quarterly compliance filings to justify the need for a non-standard product in each case. The justification must state why a standard product that could have been purchased through a more open and transparent process was not in the best interest of ratepayers.
3. Third, IOU authority is expanded for use of negotiated bilaterals for standard products in instances where there are five or fewer counterparties who can supply the product. This authority is limited only to gas and pipeline capacity.

D.04-07-028 at 17 added one more circumstance: "In addition to the limited circumstances enumerated in D.03-12-062 at Conclusion of Law 15, we authorize the utilities to engage in bilateral negotiated contracts for capacity and energy from power plants where the purpose is to enhance local area reliability."

7.4.2 Parties' Positions

PG&E argues that this proposed rule is unnecessary because current procurement rules significantly limit bilateral transactions and generally would not allow a bilateral transaction with a facility that did not make the shortlist of an RFO (outside the existing 30 day post-RFO limit). SCE contends that direct bilateral contracting is already appropriately restricted in the IOUs' AB 57 bundled procurement plans. SDG&E contends that the proposed rule is arbitrary and unnecessary, and would create administrative burden.

IEP agrees with the idea that bilateral contracts for a facility that did not make the shortlist of an RFO, as well as bilaterals selected outside of competitive processes, should be subject to the greater scrutiny of a Tier III advice letter or application. WPTF argues that the Commission should be reluctant to approve bilateral contracts that are untested through a competitive solicitation.

ORA does not support this proposal, stating that it is unclear how this proposal would enhance the current IOU contract review process and what improvements this makes. Sierra Club supports requiring an application in this situation to ensure oversight of the bilateral contract.

7.4.3 Discussion

We are not persuaded that additional procurement oversight is warranted based on the triggers suggested in the question. We agree with the utilities in that additional triggers for oversight may not be supportable at this time, and would be duplicative or redundant given the intent of the procurement rules the Commission imposes. We will not impose restrictions of this nature or create oversight triggers of this nature at this time.

7.5 Question:

What rules are needed to determine whether an IOU transaction is reasonable and therefore does not require additional review and Commission action?

7.5.1 Parties' Positions

SCE claims that all of the existing rules have been in place for several years and are working very well, thus no other rules are needed to determine whether an IOU's bundled procurement transaction is reasonable. SDG&E and PG&E agree that current rules are sufficient and no new rules are required.

IEP argues that contracts that are not the result of a competitive procurement process should be subject to greater scrutiny. WPTF states that the simplest test of reasonableness is to conduct a competitive solicitation, which by definition should result in reasonable IOU transactions.

MEA believes the Commission should review and approve any IOU transaction with a term of 12 months or longer and any transaction that could impose costs on CCA customers. ORA recommends that the Commission's Least Cost-Best Fit methodology and approval of the IOUs' bundled procurement plans should continue to be used as guidelines within the context of an advice letter or application to determine whether an IOUs' procurement transaction is reasonable. ORA does not support making exceptions to these rules that would further reduce the Commission's oversight or the up-front review process of each procurement transaction.

7.5.2 Discussion

We agree with parties who contend that current rules for determination of reasonableness of utility transactions are sufficient and not in need of revision.

8 Cost Allocation Methodology (CAM)

8.3 Questions:

The following questions related to the CAM were asked in the ALJ Ruling:

1. Is the CAM currently implemented in a manner that is sufficiently transparent or least cost?
2. Should the Commission reform the CAM energy auctions? If so, how?
3. How does the capacity allocation interact with other allocated costs such as energy efficiency and demand response funding?

4. At what stage in procurement should procurement be deemed CAM eligible, and what criteria should govern Commission decision regarding CAM allocation?
5. How should the Commission address flexibility in regards to the CAM? For example, should resources built in one IOU's service territory spread costs across all the California Public Utilities Commission's jurisdictional load-serving entities?
6. Should the CAM rules be differentiated to best account for benefit and cost allocation among community-choice aggregators and electric-service providers, based on their different business models or portfolio of other contracts? If so, how?

8.3.1 CAM Overview[8]

D.06-07-029 in the 2006 long-term procurement proceeding decision adopted the CAM, which allows the costs and benefits of new generation to be shared by all benefiting customers in an IOU's service territory. The Commission designated IOUs to procure the new generation through long-term PPAs, and the rights to the capacity were allocated among all LSEs in the IOU's service territory. The allocated capacity rights can be applied toward each LSE's RA requirements. In exchange for those benefits, the LSEs' customers – termed "benefitting customers" – pay for the net cost of the capacity.[9]

The basic framework for the CAM was set forth in D.06-07-029 as follows: The IOU would contract with an Independent Evaluator to oversee an RFO for new resource contracts. At the conclusion of the RFO, the IOU would sign a long-term contract with the generator of a new resource. The IOU would seek contract approval from the Commission, and at that time, select whether or not it

[8] Portions of this overview are taken from D.13-02-015 at 98 – 100.

[9] The energy and capacity components of the newly acquired generation are disaggregated. The net capacity cost is calculated as the net of the total cost of the contract minus the energy revenues associated with the dispatch of the contract. The non-bypassable change levied is for the net capacity cost only, and the non-IOU LSEs maintain the ability to manage their energy purchases.

intends for the CAM to apply to the contract. The Commission's decision on the IOU's application determined the applicable CAM based on allocating the appropriate net capacity costs to all benefiting customers in the IOU service area.[10] The IOU would then request Commission approval to conduct periodic auctions with an Independent Evaluator for the energy rights of the resource, essentially selling the tolling right – the energy component – and retaining the RA benefit, which it then shares with all customers paying for the capacity.[11] D.06-07-029 at 26 explained that "benefiting customers" referred to all bundled service, DA, CCA customers and "other customers who are located within a utility distribution service territory but take service from a local publicly-owned utility subsequent to the date the new generation goes into service." D.06-07-029 at 26 (footnote 21) specified that current customers of publicly-owned utilities were exempt from the CAM.

Subsequent decisions clarified and amended the CAM. D.07-09-044 presented in greater depth the procedures for the energy auctions. The procedures established a backstop for the auctions. Should an auction fail to produce a successful bid for the energy products, the capacity costs would be calculated via a specified alternative mechanism.[12] D.08-09-012 set forth that customer generation departing load was exempt from the CAM. That decision clarified that only large municipalizations were subject to the CAM, while exempting other classes of municipal departing load.

SB 695, signed into law in 2009, requires that the net capacity costs of new generation resources deemed "needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's

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[10] D.06-07-029 at 52-53.

[11] D.06-07-029 at 31-32.

[12] *See* D.07-09-044, Appendix A for specifics relating to the Joint Parties' Proposal, the alternative to the auction mechanism.

distribution service territory" must be passed on to bundled service customers, DA and CCA customers.[13] In order to align the CAM with the requirements of SB 695,

D.11-05-005 did the following:

a. Removed the right for the utility to elect or not elect CAM treatment for a resource that meets the conditions of the statues;

b. Widened the scope of the CAM to apply to UOG resources; and

c. Extended the duration of CAM treatment to match the duration of the underlying contract, eliminating the 10-year cap.[14]

SB 790 in 2011 codified the Commission requirement that the costs to ratepayers for CAM procurement must be allocated to ratepayers in a "fair and equitable" manner.[15]

Currently there are several different ways that utilities procure capacity on behalf of the customers in their service territory, both bundled and unbundled. There are demand response programs, which are funded and administered by the utilities, and whose costs are allocated to all distribution level customers in their service territory. This is done in light of the fact that all customers in their service territory may participate, and all customers in their service territory may enjoy the grid reliability benefits of these demand response programs.

Separately, the Commission created a CAM mechanism for new generation that is constructed pursuant to the LTPP for grid reliability. Finally, the CHP settlement adopted in 2011 required the utilities to procure CHP facilities to create the benefits of GHG reduction enjoyed by all customers in their

[13] Stats. 2009, ch. 337.

[14] D.11-05-005 reaffirmed that SB 695 does not require any revisions to the determinations made in D.08-09-012 regarding non-bypassable charges and the CAM process.

[15] Stats. 2011, ch. 599.

service territory. The net capacity costs of CHP procurement are also allocated to all customers in their service territory. From time to time the Commission also requires the utilities to procure facilities under special circumstances.

The Commission administers a variety of centralized procurement programs, each with impacts to bundled and non-bundled benefitting customers. The Commission may create more programs of that nature in the future, and allocate further costs to benefitting customers. No Commission determinations have been made as to how the different types of centralized procurement (CHP procurement, demand response, new generation resources pursuant to LTPP, and the recently approved energy storage procurement mandate) relate and how all these types should be evaluated in combination with the goal of providing cost effective reliability and adherence to the Commission's Loading Order.

Pursuant to D.12-06-025, Ordering Paragraph 4, LSEs are differentiated in terms of coincidence adjustment based on types of load served or load shapes. Therefore, the determination of LSE RA obligations is already differentiated between types of LSEs. In terms of CAM, the LSE's proportionate share of CAM capacity allocation depends on their forecasted peak load (with coincidence adjustment) relative to service area peak. Thus there is a slight differentiation among LSEs with regard to each LSE's CAM capacity allocation. D.12-06-025 determined that LSEs contributed to reliability need (and thus RA obligations) individually relative to the load profiles of their individual customers.

In D.13-02-015, we discussed a number of proposals by parties to make significant changes to the CAM, but declined to do so at that time. In the record of this proceeding (both Track 1 and Track 3) several parties question how the Commission makes determinations of CAM eligibility and how costs are allocated to customers. Many parties also question under what conditions the Commission should determine that a particular procurement activity creates benefits for customers.

The Commission has broadened the application of CAM considerably in recent years. As new facilities authorized under CAM have come online, the costs and CAM capacity benefits have burgeoned in recent years. In 2007, less than 500 MW of capacity were allocated via the CAM; by 2013, approximately 5000 MW were allocated through this mechanism. This figure is expected to increase to around 9000 MW by 2018.[16]

8.3.2 Parties' Positions

Overall, the utilities unanimously oppose significant changes to most CAM-related issues, other parties continue to propose innovative alternatives to perceived inequities in the current CAM process. TURN does not see any positive value in revisiting CAM issues at this time.

AReM/DACC states that they have a significant concern that all ratepayers -- including DA and CCA customers who must pay for CAM projects, energy efficiency and demand response programs -- are being double charged when utility procurement authorizations are predicated upon forecasts that presume energy efficiency and demand response will not make the expected contribution to load reductions. AReM/DACC also suggests that another element of CAM flexibility the Commission should consider would be to afford ESPs and CCAs the opportunity to self-fulfill their System or Local reliability needs and avoid CAM charges based on IOU procurement.

AReM/DACC recommends that the Commission should direct that: 1) procurement required to meet bundled customer needs is not subject to the CAM; 2) the only procurement that may be afforded CAM treatment is that which is specifically ordered by the Commission for reliability purposes and that has been demonstrated to benefit all customers; and 3) determination of whether

[16] *See* the Commission's posted Final 2014 CPUC Net Qualifying Capacity list.

customers who are served by ESPs or CCAs receive any benefit from IOU procurement must include an assessment of whether the customer's competitive supplier is already providing reliable service to those customers and meeting all the regulatory and system requirements as a load serving entity.

AReM/DACC argues that there is no process for distinguishing between system and bundled resource needs, nor a realistic test to determine who benefits from IOU procurement, as required under SB 695 in order for CAM to be used at all. AReM/DACC proposes to give the PRG and the CAM Group greater authority to reject utility procurement that is not economic or that does not represent the least-cost option for all ratepayers.

CCSF does not support having bundled customers or CCA distribution customers of one IOU be subject to CAM non-bypassable charges from procurement by another IOU. CCSF argues that the Commission has failed to precisely define the standard for CAM set forth in Section 365. l(c)(2)(A), thus allowing the IOUs to interpret the statute to support CAM for any resource that provides any degree of reliability.

SSJID contends that municipal departing load should be exempt from all CAM allocations because POUs develop and procure resources to meet the requirements of their own customers, and such resources provided by POUs have system-wide benefits equivalent to IOU-developed and procured resources. SSJID argues that charging municipal departing load for IOU capacity costs without charging IOU customers for capacity developed by the municipal departing load's Public-owned utility(POU) service provider is contrary to the Commission's indifference principle because it results in bundled customers benefiting from municipal departing load and ensuing POU capacity development.

WPTF believes that resources should be evaluated for CAM eligibility on the basis of its primary purpose. That is, if the resource was added primarily to provide supply to bundled customers, then the tangential reliability improvement should not be sufficient to justify CAM treatment. Further, WTPF argues that there is an urgent need for the Commission to develop specific criteria by which competitive suppliers are deemed to have met the reliability needs of the customers they are serving such that IOU procurement on their behalf is unnecessary and of no benefit to them – and therefore exempt from any CAM allocation of costs or net capacity.

MEA argues that the Commission must propose a clear methodology for determining the "fair share" of CAM benefits and costs so that customers of a CCA are not subjected to paying over-procurement costs. MEA recommends that the Commission determine specific reliability (operational and locational) needs which, if a resource filled such a need, would meet the CAM eligibility requirements in the Long Term Procurement Plan proceeding. This determination would be made prior to the evaluation of any specific facility. To reach this determination, MEA proposes that the Commission must evaluate the current status of RA in each of the IOUs' footprints using the following method:

- First, the Commission would undergo an analysis of unmet needs.
- Second, the Commission would determine the drivers of the unmet need; for example, if retirement of utility controlled generation is the driver of a need, then the IOU would be responsible for that procurement.
- Third, the Commission would take the remaining unmet need and offset it against known RA contracted resources which may be held by IOUs or other market participants.
- What would remain is a unique RA attribute or various unique RA attributes which are not met by existing RA rules, and which is not driven by bundled load. This is the CAM-eligible need. The CAM-eligible need should be clearly specified in MW or a range of MWs, and the RA attribute which would meet the CAM eligibility requirements.

MEA argues that the CAM should not reach beyond the footprint of a given IOU. MEA states that both energy efficiency and demand response have impacts on the RA needs of a LSE, both from a peak load perspective and from an average demand perspective. MEA notes that under the energy efficiency model, it is understood that any entity providing energy efficiency programs provides a benefit to all customers. MEA sees CAM as a one-way street, where an IOU's procurement can "benefit all customers" but the CCA's procurement which also benefits all customers is not acknowledged under the current methodology.

MEA proposes two alternatives:

1) Each LSE is required to procure its own RA in accordance with Commission-mandated requirement and no LSE is allowed to allocate those costs to another LSE unless an exigent circumstance arises; or
2) To the greatest extent possible, any CAM allocation of IOU procurement is offset, in the case of CCAs, with procurement undertaken by the CCA and the value that procurement provides. To accomplish this, the Commission could adopt an optional mechanism for CCAs who are willing to provide additional documentation to the Commission such as through an advice letter filing so that the CAM cost and capacity allocation could be offset by the CCA's own procured resources. MEA believes an optional mechanism is appropriate in order to respect jurisdictional authority and CCA procurement autonomy.

MEA also recommends allowing for third party demand response and energy efficiency resources to compete in an all-source request for offers to fill the identified CAM resource need.

ORA supports a process by which the Commission should assume sufficient preferred resources will materialize to meet system and local area need rather than not, and direct the IOUs to develop their preferred resource programs in a manner that will produce those results. Reduction of the need for new system and local area reliability resources through EE and DR procurement will minimize CAM procurement. ORA recommends that the Commission direct the IOUs to work with CAISO to determine a priority ordered listing of the most electrically beneficial locations for preferred resource deployment (supply or demand side) in a systemic way to maximize these resources' ability to reduce system and local area need. For local capacity requirements (LCR), such a listing should use a reasonable level of electrical aggregation—at the very minimum the LCR sub-area or if possible, a finer electrical-location granularity such as substations.

8.3.3 Discussion

In this section, we consider the CAM issues raised in this proceeding in general. We give general direction regarding the future of CAM here; in the next sections we specifically address issues related to the CAM auction and CAM resource procurement outside of a utility's territory (questions 2 and 5 above). We note that many CAM-related issued were resolved in Track 1 of this proceeding (D.13-02-015); we do not provide for relitigation of these issues here.

The questions in this section highlight the way that planning for system reliability must be coordinated, and that all capacity that is procured is seen transparently. The costs allocated to benefitting customers for these disparate capacity and energy procurement programs must be weighed against each other, to ensure that the most cost effective choices are made and that there is sensitivity to how much central procurement is warranted and appropriate.

Because various parties have continued to question the basis upon which the Commission determines the eligibility of a particular resource procurement for CAM treatment, we take this opportunity to explain our policy further. Bundled procurement undertaken pursuant to a utility's AB 57 bundled procurement plan is normally not subject to the CAM. On the other hand, procurement that a utility is authorized or directed to undertake in the "system track" of the LTPP, to meet local or system (including flexibility) reliability needs, will ordinarily be subject to the CAM. Thus, the answer to the fourth question in this section: "At what stage in procurement should procurement be deemed CAM eligible, and what criteria should govern Commission decision[s] regarding CAM allocation?" follows directly from these basic principles. When the Commission in the LTPP (or other appropriate proceeding) authorizes or directs a utility to procure resources to meet system or local reliability needs, the CAM applies. Absent such authorization or direction, CAM does not apply, unless otherwise stated in a specific Commission decision. Since bundled plans rarely if ever direct particular procurements, this distinction should be reasonably transparent to all parties.

Routine procurement to meet a utility's near-term resource adequacy requirements for its bundled service customers would not normally be subject to CAM, nor would such procurement by a non-IOU LSE. On the other hand, long-term utility procurement undertaken to develop new or expanded infrastructure to meet system or local reliability needs in its distribution service area will typically be subject to CAM, and the RA value of such resources will be allocated to all LSEs. To our knowledge, ESPs and CCAs have not engaged in such long-term infrastructure procurement, except perhaps in the RPS context. IOUs, ESPs and CCAs each meet their own individual RPS procurement requirements, and the costs of those contracts are not normally subject to CAM treatment.

One issue which was raised in Track 1 of this proceeding was whether there should be a cap on CAM allocations. This approach was rejected in D.13-02-015.[17] Other changes to CAM were also rejected in that decision.[18] A proposal related to CAM opt-out for ESPs and CCAs was not adopted in

[17] *See* D.13-02-015 at 109-110.

[18] *See* D.13-02-015, Findings of Fact 50, 51 and 52.

D.13-02-015, but was not rejected. Finding of Fact 54 stated: "In AReM's CAM opt-out proposal, it is unclear how AReM's five-year contract term/project life requirement would adequately ensure investment in new resources." Finding of Fact 55 stated: "It is not clear that a CAM opt-out could be implemented without undue administrative burden." Conclusion of Law 23 stated: "The record is insufficient to resolve outstanding questions about a CAM opt-out at this time." We do not have sufficient additional record in this Track of the proceeding to conclusively analyze CAM opt-out proposals.

8.4 Question:

Should the Commission reform the CAM energy auctions? If so, how?

8.4.1 Current Rule

Pursuant to D.07-09-044 and the Joint Party Proposal (JPP) adopted in that decision, utilities have a choice to use the energy auction or a mechanism that relies on MRTU for energy pricing to set the energy revenue which would debit against contract costs to create the net residual capacity costs for allocation under the CAM. The JPP mechanism for calculating net capacity costs outlines the principles to be applied in energy auctions used to determine net capacity costs.

8.4.2 Parties' Positions

PG&E recommends that the energy auction process for the CAM be eliminated. PG&E advocates for a net cost allocation methodology to determine the net capacity costs of specific contracts without the need for an energy auction, as used in other recent cases, for all CAM-eligible resources and the energy auction should be eliminated. SCE notes that it is the only IOU that has held energy auctions. In SCE's experience, energy auctions have served their intended purpose and the energy auction process has worked well. Therefore, SCE does not see a need to reform the CAM energy auctions at this time. SCE seeks to allow the utilities to make a request to refrain from conducting an energy auction when an energy auction is neither appropriate nor necessary.

SDG&E comments that, in previously considering application of the CAM to IOU procurement, the Commission permitted parties to establish a proxy calculation similar to the non-auction cost calculation mechanism adopted in D.07-09-044 in the JPP. SDG&E proposes that the JPP (or an administrative methodology based on the JPP) be deemed to be a fully-available alternative to the use of an energy auction to determine the net capacity costs for resources subject to the CAM. SDG&E recommends eliminating the restriction that the administrative methodology may be used only if an auction is unsuccessful or has not yet occurred.

WPTF believes the Commission should examine carefully how to value the energy component and the residual capacity costs, whether through an auction or otherwise. WPTF argues that by ascribing too little value to the energy component, the IOU is able to layer more net capacity costs on its competitive CCA and ESP suppliers, resulting in an unnecessary and unfair cost shifting to retail choice customers. WPTF emphasizes that it is important for the Commission to ensure that the full value of energy and other related products is netted from the contract price, as proposed by MEA, and AReM/DACC in the recent phase of this proceeding.

AReM/DACC's fundamental concern with the energy auction and the proxy calculation used when there is no auction is that they rely on the short-term value of energy to produce an imputed capacity value from a long-term contract price. D.07-09-044 requires that the back-to-back toll product available for the energy auction be limited to a term not to exceed five years. AReM/DACC believes that the Commission should consider modifying this restriction to allow the auction products of a longer duration, and should consider implementing a longer minimum term (currently at one year) to better reflect the incremental hedging value of the PPA. AReM/DACC also believes that JPP should be reexamined so that the full value of energy and other products is netted from the contract price.

Whether or not the Commission decides to reform the CAM energy auctions, MEA believes the Commission ought to ensure that CAM-eligible procurement is driven solely by reliability needs.

8.4.3 Discussion

In D.13-02-015, we considered potential changes to the CAM energy auction. At that time, we found: "The record does not provide an adequate and persuasive basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism." (D.13-02-015, Finding of Fact 53.) With the additional comment in this Track of the proceeding, we are now prepared to act on this issue. We will now eliminate any requirement that a utility undertake a CAM energy auction as a tool to net capacity costs for CAM facilities.

For reasons of transparency and accuracy, parties' comments largely recommend removal of the CAM energy auction. While there may be benefits to such energy auctions (*e.g.*, the hedging benefits of longer term tolling agreements relative to the short term JPP), there are also benefits to having shorter term ways to net capacity costs if situations change.

We are concerned with protecting all ratepayers, and need to ensure that all ratepayer groups (including DA and CCA load) are treated equally. This is the reason that the CAM was developed in the first place – to ensure that all ratepayer groups were treated equally. We conclude that it would be unfair to create a system that allows one ratepayer group to allocate costs to other ratepayers when there is reason to believe that those costs are not sufficiently justified or that the costs are likely to mismatch actual market value.

While the JPP might arrive at costs that are not always indicators of real value, given the complexity of the CAISO markets, the mechanics of the JPP allow for a forecast and a true up later. On the other hand, the energy auctions arrive at the highest bid, regardless of future energy prices, and there are insufficient safeguards to ensure that the final award is accurate or that the auction itself is fair and robust. There are elements of the auction that may not present true equality between bidding parties. It is also unclear if the tolling agreements that result from the energy auctions abide by the CAISO tariff or allow for implementation of CAISO tariff the way a toll with the original purchaser would. For example, requirements for generators to submit economic bids to count for flexibility for can be problematic when the owner of the plant sells a tolling agreement, where the purchaser might not be the scheduling coordinator. The replacement requirement for RA resources that take planned maintenance may lead to compliance problems when the facility is not scheduled by the same party that owns the tolling agreement.

For these reasons, we remove the requirement for an energy auction as a tool to net capacity costs for CAM facilities, and instead allow all utilities to utilize the mechanism adopted in the JPP to set the residual capacity costs that would be allocated to benefitting customers.

8.4.4 Question:

Should resources built in one IOU's service territory spread costs across all the California Public Utilities Commission's jurisdictional load-serving entities?

8.4.5 Parties Positions

PG&E recommends that the Commission should determine if the flexibility need being met by the resource is a system or local reliability need, and if the resource meets that reliability need in a manner that benefits all customers of the IOU being ordered to procure it. If so, PG&E recommends that the net capacity costs are to be allocated to the bundled, DA, and CCA customers in the distribution service territory of the IOU ordered to procure the resource, and not to the bundled, DA, and CCA of customers in the distribution service territory of other IOUs.

SCE recommends that, to the extent that a system need exists for new flexible generation resources, but it is preferable to site all the new resources in one IOU's service territory, the Commission should take action to ensure an equitable allocation of cost to all CPUC-jurisdictional customers by requiring each IOU to contract for new flexible generation resources on a load ratio share basis in the identified IOU's service territory. Alternatively, SCE suggests the Commission can authorize one IOU to contract for the required new flexible generation resources and allocate a load ratio share of the CAM costs to the other two IOUs for recovery from their system customers.

SDG&E considers it to be premature to address this issue at this time.

AReM/DACC recommends that, along with ensuring that the application of CAM takes into account whether an ESP or CCA is already meeting the reliability needs of their customers and therefore should be exempt from CAM, the Commission should consider would be to afford ESPs and CCAs the opportunity to self-fulfill their system or local reliability needs and avoid CAM charges based on IOU procurement.

CCSF does not support having bundled customers or CCA distribution customers of one IOU subject to CAM non-bypassable charges from procurement by another IOU. MEA believes the CAM should not reach beyond the footprint of a given IOU because small LSE's such as MEA would face a significant burden in monitoring procurement proceedings of all three IOUs in order to represent the interests of their customers.

8.4.6 Discussion

We agree with PG&E, CCSF, and MEA that the criteria to justify CAM procurement should be specific enough that the procurement can be focused on one IOU service area or another, and that it is unreasonable for one IOU's customers to subsidize the reliability improvements of another. A concern with applying the CAM in this context is that the customers paying for the CAM facility would see only incremental benefit from the facility, while another IOU's customers would not pay for the reliability improvements they enjoy.

While it is sometimes advisable to focus procurement in a certain place, we find it reasonable to require each IOU to manage the reliability of its own service area. We do not expect to require all IOUs to share the costs of incremental new facilities, but instead to authorize construction by each IOU for the load nearest them. It is not efficient or effective for a customer to receive Local RA credit for a facility in another service area, since the LSE serving that customer would not have the applicable Local RA obligation to offset. This proposition seems to violate principles of cost causation, and creates possibility of excess procurement.

9 Energy Resource Recovery Account (ERRA) compliance filing requirements

9.3 Question:

Should the Commission require more consistency among the QCR's for the three major electric IOUs? If so, what areas of the QCRs currently lack consistency?

9.3.1 Current Rule

The current format and timing of the QCR submission was set via Commission decision D.07-12-052. There was a template adopted there that specified the format of the reports and the content of the attachments.

9.3.2 Parties' Positions

PG&E does not see a need to make changes to the QCR at this time. SCE and SDG&E claim there is a high degree of consistency currently exists among IOUs' QCRs.

ORA recommends that the Commission should develop a more consistent and standardized reporting template for the QCRs filed by the IOUs. One particular area where ORA believes the QCRs lack consistency is in the reporting format for newly signed electricity contracts.

CEJA urges the Commission to require consistency in the format for energy resource recovery account compliance reports among the three major IOUs to allow interested members of the public and regulators to easily review the information presented.

9.4 Question:

Are any changes to information filed in QCRs necessary to ensure that IOU procurement is compliant with Commission rules?

9.4.1 Current Rule

The current QCR format was adopted by D.07-12-052. The format has grown large, with utilities filing multiple attachments with a large amount of information. There is also a standing monthly data request that the utilities have been submitting since its issuance in 2004. To some extent these two data submissions are duplicative. In addition there are numerous data requests that Energy Division staff submits to the utilities for various elements of their procurement data.

9.4.2 Parties' Positions

PG&E, SCE and SDG&E agree that there is no inconsistency among the IOUs in the information presented in the QCRs.

MEA finds the current QCRs to be largely useless to the public due to assertions of confidentiality over the most relevant procurement information. Consistent with MEA's earlier comments regarding the need for greater IOU procurement transparency, the IOUs should include more substantive information in the public versions of the QCRs. CEJA recommends that the

Commission require that the quarterly compliance reports include information on the three major electric IOUs' loading order compliance.

9.5 Question:

Should the QCR evaluation process be moved from a quarterly evaluation to an annual, semiannual (or other term) process?

9.5.1 Current Rule

The current rule places the QCR submission on quarterly basis.

9.5.2 Parties' Positions

PG&E, SCE and SDG&E all maintain that the QCR evaluation process should remain a quarterly evaluation. PG&E contends the quarterly cycle is the optimum in terms of ensuring the IOUs' transactions are expeditiously reviewed against the IOUs' Commission-approved procurement plan's upfront standards, consistent with Public Utilities Code Section 454.5(c)(3).

CEJA urges the Commission to continue requiring the quarterly compliance reports every quarter.

ORA recommends the following: 1) The Commission should require each IOU to submit a Contract Amendment Compliance Report prepared by an authorized Independent Evaluator as an appendix to the IOU's Energy Resource Recovery Account Annual Compliance Application; and 2)The Commission should require an independent process evaluation of each IOU's Least-Cost Dispatch methods, procedures, documentation, software models, and model assumptions once per two years.

9.6 Discussion of Questions 9.1, 9.2 and 9.3 (ERRA filing requirements)

It is necessary to balance the need for greater information access with the difficulty in producing that information and in evaluating it. Commission staff (as well as stakeholders or PRG members) must be able to use the information submitted in a useful way. Even if the Commission aggregates and publishes reports for the public in the interests of managing transparency, the information must at first be clear and usable. In addition to PRG members who have a use for procurement information related to procurement oversight, the CAISO has a use for mid to long term procurement information to inform CAISO decisions about backstop procurement or forecasts of potential resource retirement.

In our evaluation of the QCR format, we find that there is sufficient consistency as to format, but there may be needs for added consistency as to purpose and meaning. We find that the QCR submissions are sufficiently standardized as ordered by Commission decision. However, the information presented is complicated and voluminous. Information presented in the QCRs is often also available from other sources, so it is unclear what the best way to get the data and minimize reporting is. Currently it is unclear as to how to best effectuate the purpose of the QCR submissions (procurement oversight and assurance that the utilities are following their procurement rules) so several areas of the QCR reports could be redundant or unnecessary. A reevaluation of the purpose and content would aid Commission staff in making best use of the QCR data. This reevaluation is likely to reveal that needs have changed since the QCR format was last amended in 2008; for example, some information may be needed once per year, and some information needed quarterly. We will seek to standardize how the Commission receives and stores utility procurement data.

At this time, no changes to content or timing are adopted. We will require Energy Division to begin investigating opportunities to understand and potentially reduce the QCR reporting to just the most useful elements, to eliminate redundant reporting, and to create guidelines that enable consistency across the utility QCR submissions.

We adopt a process for QCR revisions. The process should occur within the next 90 days, be cooperative, and create a QCR guide similar to the guide for RA reporting. We require the utilities to devote a portion of an upcoming

PRG meeting to this task, by discussing the information they currently submit in the QCRs with PRG members, describing why the data is submitted (particularly data that is also available online or data that is submitted pursuant to other data requests) and to ensure that PRG members have had a chance to comment on the content and format of the QCRs for their purposes as PRG members.

There are a variety of purposes for QCR information, including the auditing functions of ensuring that the procurement rules are met. Energy Division staff will lead a dialogue to ensure that all users of the QCR data are able to continue achieving their goals with whatever new guidelines are promulgated.

10 Refinements to the Independent Evaluator (IE) program

10.1 Question:

Please comment on the following proposal:

i. The rules for whom or which entity may qualify to be in the IE pool remain the same;

ii. The IOUs may not limit the IE's interactions with the Commission, specifically in terms of nondisclosure agreements that restrict information sharing;

iii. IEs are positioned on particular assignments through a random selection process, removing IOU influence over which IE may be assigned; and

iv. IEs may remain in the selection pool for 10 years (rather than up to 6 years), subject to evaluation every 3 years (maintain current requirement for reassessment).

10.2 Parties Comments

PG&E endorses keeping the current rules for IE qualification in place. PG&E supports having an IE remain in the selection pool for ten years and subject to evaluation every three years. SCE agrees that the rules pursuant to D.04-12-048 and D.07-12-052 for whom or which entity may qualify to be in the IE pool should remain the same. SCE is not aware of any specific IOU behavior that has sought to limit an IE's interactions with the Commission. SCE believes

that, consistent with the guidance provided in D.04-12-048, the IE selection process should be based on the skills offered by the IE, not a randomized process that would preclude the ability to match an IE's experience and knowledge to a particular solicitation process and energy products. SCE supports a proposal for IEs to remain in the selection pool for ten years, subject to evaluation every
three years.

SDG&E does not recommend modifying the requirements for IE qualifications or assignments. SDG&E states that its nondisclosure agreement does not restrict IE interactions with the Commission; SDG&E claims that it does not attempt in any way to restrict information-sharing between the IE and the Commission.

WPTF considers the proposal cited as an improvement over the existing rules. WPTF recommends having the Commission's Energy Division, rather than the utilities, oversee the hiring and oversight of IEs in this LTPP.

Sierra Club recommends that, rather than perpetuating a system that has structural conflicts of interest built in the system, the Commission require its staff auditors to evaluate IOU procurement. CEJA requests that the rules for qualifying for the IE pool be modified to include qualifications to review other types of resources and environmental considerations including environmental justice.

IEP supports this proposal.

ORA agrees that the IOUs should not limit the IE's interactions with the Commission, specifically in terms of nondisclosure agreements which may restrict information sharing with the Commission. ORA opposes a random selection process of IEs on particular assignments because it may not select the best-fit IE, all factors taken into consideration, for a specific project. ORA does not oppose SCE's proposal to allow IEs to remain in the selection pool for up to three years, but opposes allowing IEs to remain in the selection pool for 10 years on the basis that this would impede other potential IE candidates from competing for an IE role.

CEJA supports parts (ii) and (iii) because these proposals may reduce potential conflicts and allow for an independent evaluation. CEJA does not support part (iv) because of the potential for conflicts that arise after participating in the process for a number of years.

10.2.1 Discussion

We agree with PG&E that it is not necessary to change the rules for whom or which entity may qualify to be in the IE pool. The current rules pursuant to D.04-12-048 and D.07-12-052 ensure that experienced and well-qualified candidates are selected for the pool.

There is no evidence that IOUs have limited the IE's interaction with the Commission in terms of nondisclosure agreements that restrict information sharing. New rules facilitating IE interaction with the Commission are not necessary.

Currently, IEs are assigned projects by matching their expertise and experience with the needs of a project. We agree with SCE and ORA that it is beneficial to match the IE's expertise and skills with details of a particular assignment. Using a random selection process for IE assignment does not provide such benefit. Therefore, the Commission will retain the current process for IE assignment.

Existing rules allow IEs to remain in the selection pool indefinitely while subject to re-evaluation every two years, pursuant to D.07-12-052. We do not find a need to limit the terms of IEs in the pool. We agree with PG&E and SCE that IEs can be re-evaluated every three years instead of two years to provide more opportunity for IEs to demonstrate their performance. Therefore, the Commission will continue to allow IEs to remain in the selection pool without term limits, subject to evaluation every three years instead of every two years.

11 Comments on Proposed Decision

The proposed decision 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 ____________________.

12 Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and David M. Gamson is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. IOU procurement of authorized energy, natural gas, emissions and financial hedging products is restricted by predetermined volume limits and transaction rate limits approved in the bundled procurement plan, based on a forecast of future procurement needs. In effect, the bundled procurement plan provides an upper limit on procurement.

2. Procurement levels for fossil-fuel resources or preferred resources are addressed through Commission policies in various proceedings (including other phases of this one) which seek to implement statutes, policies and goals in these areas.

3. While there are potential benefits of mandating minimum procurement limits, it is not possible at this time to ensure that bundled customers would not bear a disproportionate share of reliability costs.

4. Minimum procurement levels are already established in the RA proceeding. Additional minimum procurement requirements for any particular electric product or service could increase ratepayer costs.

5. IOUs are expected to plan for reasonable amounts of departing load and

then only procure for the assumed amounts of retained bundled load. IOUs appear to take into account their expectations for departing load in their procurement forecasts.

6. There may be a difference between the IOU's calculation of departing load and other objective measures of departing load, thus necessitating clarification of rules.

7. The current rules governing confidential treatment of IOU data are set forth in D.06-06-066.

8. The Commission has not to date allowed public disclosure of RFO bid and offer information, as such disclosure could reasonably be expected to affect the market to the detriment of IOUs and their ratepayers. Nothing has changed in this regard.

9. Allowing for the incremental capacity of existing plants or repowered plants to participate in long-term RFOs may alleviate some need to build additional capacity. Allowing for such capacity to participate in long-term RFOs may enhance the operation of the plant and increase its value to the system.

10. There are no current restrictions on contract lengths for new facilities.

11. There is a gap in Commission policies regarding review of medium term bilateral procurement contracts of three consecutive months or greater and under five years in duration (with the exception that power purchase agreements with OTC plants with contract duration of greater than two years must be submitted to the Commission's via a Tier III advice letter).

12. While there are benefits to CAM energy auctions, such as the hedging benefits of longer term tolling agreements, there are also benefits to having shorter term ways to net capacity costs if situations change.

13. The CAM was developed to ensure that all ratepayer groups were treated equally.

14. The energy auctions arrive at the highest bid, regardless of future energy

prices, and there are insufficient safeguards (such as a forecast and a true up) to ensure that the final award is accurate or that the auction itself is fair and robust.

15. There are dynamics to the energy auction that may not present true equality between bidding parties.

16. Applying the CAM process to resources located in another IOU's service area could result in customers who pay for the CAM facility seeing little or no benefit from the facility, while another IOU's customers do not pay for the reliability improvements they enjoy.

17. It is not efficient or effective for a customer to receive Local RA credit for a facility in another service area, since the LSE serving that customer would not have the applicable Local RA obligation to offset.

18. Utilities currently have no authorization to construct facilities outside their service area for reliability purposes, and demand response programs focus on customers that the utilities bill directly.

19. Quarterly compliance report submissions are sufficiently standardized but the information presented is complicated and voluminous.

20. A reevaluation of the purpose and content of quarterly compliance reports would aid Commission staff in making best use of the data in these reports.

21. The current rules pursuant to D.04-12-048 and D.07-12-052 ensure that experienced and well-qualified candidates are selected for the IE pool. However, evaluation of IEs every two years provides limited opportunity for IEs to demonstrate their performance.

22. There is no evidence that IOUs have limited the IE's interaction with the Commission in terms of nondisclosure agreements that restrict information sharing.

Conclusions of Law

1. It is not necessary to establish new minimum or maximum procurement levels for bundled procurement plans at this time, as there is no corresponding or

overriding benefit to further minimum procurement requirements.

2. The Public Utility Code Section 454.5(b)(9) requirement of "a showing that the procurement plan will fulfill its unmet resource needs from eligible renewable energy resources in an amount sufficient to meet its procurement requirements pursuant to the California Renewables Portfolio Standard Program" and that each utility "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible" is ongoing.

3. Issues regarding centralized capacity markets are not within the scope of this proceeding. Similarly, multi-year forward contracting requirements should not be considered in this proceeding. Issues regarding limits on flexible capacity are encompassed in the RA proceeding.

4. It is necessary to clarify requirements from D.12-01-033 regarding calculations of departing load in utility procurement forecasts.

5. It is not in the public interest to provide public disclosure of RFO bid and offer information at this time.

6. It is in the public interest to promote greater reporting of the information that the Commission regularly collects from the utilities regarding procurement activities, either as aggregate or in specific, to the market and the CAISO, to the extent that confidentiality is not compromised.

7. In order to allow incremental capacity to bid into a new generation RFO, the term "incremental capacity" should be defined as: "capacity incremental to what was assumed in the underlying needs assessment." In this context, the following terms should also be defined:

- Upgraded plants: Upgrades are defined as expanding the generation capacity at, or enhancing the operation of, a generation facility, so long as such incremental megawatts can provide the necessary attributes that the Commission has authorized the utility to procure. An upgraded plant or a plant with incremental capacity additions would be a plant where the main generating equipment is retained and continues to operate.

- Repowered plants: Repowers are defined as capital investments that extend the useful life of a generation facility, after the planned retirement date. A repowered facility is a facility where the main generating equipment (such as the turbine) is changed out for new equipment.

8. It is in the public interest to impose greater oversight of medium term bilateral contracts. Utilities will now be required to submit Tier II Advice Letters seeking Commission approval to enter into a medium-term bilateral contract if the size of the contract is over 50 MW. This rule is in addition to all previous procurement rules.

9. It would be unfair to create a CAM system that allows one ratepayer group to allocate costs to other ratepayers when there is reason to believe that those costs are not sufficiently justified.

10. Energy auctions should no longer be required to net capacity costs for CAM facilities. Instead all utilities should use the mechanism adopted in the JPP to set the residual capacity costs that would be allocated to benefitting customers.

11. Except as currently provided for in the CHP settlement, it is unreasonable to use the CAM process so that one IOU's customers subsidize the reliability improvements of another; it is reasonable to require each IOU to manage the reliability of its own service area.

12. At this time, no changes to content or timing of quarterly compliance reports should be adopted, pending Energy Division review of opportunities to reduce such reporting to the most useful elements, to eliminate redundant reporting, and to create guidelines that enable consistency across the utility submissions.

13. There is no need to change the IE rules regarding: a) which entity may qualify to be in the IE pool; b) IE interaction with the Commission; and c) the

current process for IE assignment.

14. It is reasonable to allow IEs to be re-evaluated every three years instead of two years to provide more opportunity for IEs to demonstrate their performance.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company (collectively, the IOUs) shall estimate reasonable levels of expected Direct Access and Community Choice Aggregation departing load over the 10-year term of the IOUs bundled plans, using information provided by the California Energy Commission and/or by a Community Choice Aggregator in its Binding Notice of Intent. The IOUs shall then exclude this departing load from their future bundled procurement plans, and only procure for the assumed amounts of retained bundled load. Having been excluded from the bundled portfolio planning scenarios, the forecasted Direct Access and Community Choice Aggregation departing load shall not be subject to non-bypassable charges for any incremental stranded procurement costs incurred by the IOUs for the period after the date of departure assumed in their approved bundled plans.

2. In order to allow incremental capacity to bid into a new generation Request for Offers, the term "incremental capacity" is defined as: "capacity incremental to what was assumed in the underlying needs assessment." In this context, the following terms are also defined:

    1. <u>Upgraded plants</u>: Upgrades are defined as expanding the generation capacity at, or enhancing the operation of, a generation facility, so long as such incremental megawatts can provide the necessary attributes that the Commission has authorized the utility to procure. An upgraded plant or a plant with incremental capacity additions would be a

plant where the main generating equipment is retained and continues to operate.

2. Repowered plants: Repowers are defined as capital investments that extend the useful life of a generation facility, after the planned retirement date. A repowered facility is a facility where the main generating equipment (such as the turbine) is changed out for new equipment.

3. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall submit Tier II Advice Letters seeking Commission approval to enter into a medium-term bilateral contract if the size of the contract is over 50 megawatts. This rule is in addition to all previous procurement rules.

4. Energy auctions shall no longer be required to net capacity costs for facilities subject to the Cost Allocation Mechanism. Instead Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall use the mechanism adopted in Decision 07-09-044, known as the "Joint Parties' Proposal," to set the residual capacity costs that would be allocated to benefitting customers.

5. No later than ninety (90) days after the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company devote a portion of an upcoming Procurement Review Group meeting to creation of a quarterly compliance reporting guide similar to the guide for Resource Adequacy reporting.

6. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall re-evaluate Independent Evaluators every three years.

7. The September 20, 2012 Motion of Pacific Gas and Electric Company to move Track 3 multi-year procurement issues to the Resource Adequacy proceeding (Rulemaking 11-10-023 or its successor), and other matters, is denied.

8. Rulemaking 12-03-014 shall remain open.

This order is effective today.

Dated __________ _____ _____ _____ , at San Francisco, California.