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Decision 06-07-029 July 20, 2006

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 06-02-013 (Filed February 16, 2006)

OPINION ON NEW GENERATION AND LONG-TERM CONTRACT PROPOSALS AND COST ALLOCATION

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OPINION ON NEW GENERATION AND LONG-TERM CONTRACT PROPOSALS AND COST ALLOCATION

Executive Summary

The electricity market crisis of 2000-2001 cut short the restructuring process envisioned by Assembly Bill (AB) 1890, and numerous developments since then have left California with a hybrid market structure subject to significant legislative mandates. Direct Access (DA) was frozen by the Legislature, several non-bypassable charges have been imposed on migrating customers, and the bankruptcies and litigation that followed the crisis have resulted in acquisition of new power plants by the investor-owned utilities (IOU). These developments have left some questioning what is the future of the California electricity market.

With this decision today, the Commission seeks to signal that it is committed to the fundamental principles that have guided electricity market restructuring in California and elsewhere: competition and customer choice. In particular, we intend to pursue policies to develop and maintain a viable and workably competitive wholesale generation sector in order to assure least cost procurement for bundled utility customers. At an appropriate juncture, in another proceeding, we intend to explore how we may increase customer choice, by reinstituting DA or via other suitable means. In the interim, we will strike a balance between requiring that electric service providers (ESP) are "responsible citizens" while ensuring that our actions do not undermine the ESP's business model.

However, determining the appropriate market model and developing the necessary institutional infrastructure takes time and a more extensive record than we have developed thus far in this proceeding. Phase II of this proceeding, in tandem with Phase II of the Resource Adequacy (RA) proceeding, Rulemaking (R.) 05-12-013 will tackle the longer term market structure questions.

Our foremost responsibility is to assure continued reliable service at reasonable cost. At this point in time, we are faced with the urgent need to bring new capacity on line as soon as 2009, at least for Southern California. We therefore devoted Phase I of this proceeding to working with the known need and we found that in order to maintain adequate capacity and reserves throughout the state, 3,700 megawatts (MW) of new generation must come on line beginning in 2009. The required new resources are *in addition* to the investments the IOU's are expected to make in energy efficiency and renewable generation and are consistent with the State's Loading Order policy, the goals established in Energy Action Plans I and II, the Commission's greenhouse gas policy, and Commission decisions implementing these policies.

Given the significant savings resulting from making use of pre-existing transmission and gas interconnections at brownfield sites, we strongly encourage market participants to take advantage of opportunities to repower older facilities. For the purposes of upcoming requests for offers (RFO), new generation should be understood to encompass both greenfield facilities and repowers of existing units, where feasible and appropriate.

The more challenging question we faced was how to assure timely construction of the necessary capacity without compromising our longer term goals of achieving competition and customer choice. The only complete solution presented to the Commission was the Joint Parties' proposal (JP). The JP would make the IOUs the entities responsible for acquiring new generation capacity, on a temporary basis, for bundled and unbundled customers alike. While other parties offered critiques of the JP, their alternative solution can be summarized simply as "stay the course": continue with ongoing market reforms and somehow or other the new capacity will get built.

Given the urgent need for new capacity and the lengthy lead-times required both for new construction and to develop and implement new market institutions, we conclude that staying the course is too risky. Developers have indicated that they require long-term contracts to undertake new projects, and both ESPs and IOUs are unwilling to sign long-term contracts in the current regulatory and market framework. ESPs' customers are on short-term contracts and ESPs are currently unable to recruit new customers with the suspension of DA. IOUs are concerned that without assurances that the associated costs of long-term contracts can be passed on to customers that have already left bundled service, or that adequate capacity would be available to serve DA customers that opt to return to bundled service, long-term contracts are too risky.

This presents a recipe for stalemate and, ultimately, scarcity. We therefore conclude that immediate and affirmative Commission action is required to assure construction of adequate new capacity during the time in which we are transitioning to more robust and durable market institutions.

Accordingly, we will adopt a modified version of the JPs' proposal *on a limited and transitional basis*. This new cost-allocation mechanism will not apply to commitments made after new institutions are decided upon, developed and in place. We will not approve this cost allocation for any additional utility-owned generation, since that generation is essentially dedicated to bundled customers. We adopt recommendations from the Indicated Parties in order to limit the procurement role of the IOUs. The proposal's salient feature is that it divides the management of the energy and capacity components of the newly acquired generation, so that the IOUs are not responsible for the energy management of the new capacity by default. Instead, the energy component of new generation contracts would be managed by the entity that values the energy the most, as revealed through an auction or other bidding process. This practice is consistent with both ESPs and IOUs managing their energy purchases separately. Implementation details for this proposal will be worked out in Phase II of this proceeding.

We are supportive of the proposal that load serving entities (LSEs) that can demonstrate that they are fully resource adequate over a sufficiently long time horizon should be allowed to opt-out of the cost-allocation system. In Phase II of R.05-12-013, we will consider proposals for how an opt-out system can be designed and implemented, concurrent with our consideration of multi-year resource adequacy and capacity markets.

Phase II of this proceeding will provide guidance for how the IOUs are to conduct their forthcoming procurement processes.

Our intent is that the long-term market rules and institutions to be developed in Phase II of the RA proceeding will supersede these temporary arrangements. That proceeding will examine creating multi-year RA requirements for all LSEs as well as capacity markets and other arrangements for assuring that sufficient generation is built when and where it is needed. Potentially, cost recovery for plants built pursuant to these temporary arrangements ordered in this decision may be completed under the new structure, with a seamless transition, depending on the details of the new structure.

I. Introduction

As we announced in the Order Instituting Rulemaking (OIR) initiating this rulemaking, "The first order of business for this proceeding will be to examine the need for additional policies that support new generation and long-term contracts for California, including consideration of transitional and/or permanent mechanisms (e.g., cost allocation and benefit sharing, or some other alternative) which can ensure construction of and investment in new generation in a timely fashion."

Simultaneously with this focus on new generation, the Commission also indicated its interest in capacity markets and exploring the concept and mechanisms of capacity markets in Phase II of the companion procurement R.05-12-013.

The State's energy policies — as noted in the Commission's and the California Energy Commission's (CEC) Energy Action Plan II (EAP II)[1] and the CEC's Integrated Energy Policy Report (IEPR) – uniformly point to the need for the State to invest in new generation in both northern and southern California.

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[1] In EAP II, a policy statement issued jointly by both the Commission and the CEC, established a set of priorities for the energy policy for the State. See http://www.cpuc.ca.gov/PUBLISHED/REPORT/50480.htm.

In EAP II, we state, "Significant capital investments are needed to augment existing facilities, replace aging infrastructure, and ensure that California's electrical supplies will meet current and future needs at reasonable prices and without over-reliance on a single fuel source." Even with the emphasis on energy efficiency, demand response, renewable resources, and distributed generation, investments in conventional power plants will be needed. The State will work to establish a regulatory climate that encourages investment in environmentally-sound conventional electricity.

Key Actions 3 and 4 implementing "Electricity Adequacy, Reliability and Infrastructure" state we will "encourage the development of cost-effective, highly-efficient, and environmentally-sound supply resources [after incorporating higher loading order resources] to provide reliability and consistency with the State's energy priorities," and "establish appropriate incentives for the development and operation of new generation to replace the least efficient and least environmentally sound of California's aging power plants."

Therefore, we are adopting a cost-allocation mechanism, on a limited and transitional basis, that allows the advantages and costs of new generation to be shared by all benefiting customers in an IOU's service territory. We designate the IOUs to procure this new generation. The LSEs in the IOU's service territory will be allocated rights to the capacity that can be applied toward each LSE's RA requirements. The LSEs' customers receiving the benefit of this additional capacity pay only for the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract.

In light of the adoption of this new cost allocation mechanism, we order Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) to proceed expeditiously to procure new generation, as previously authorized in Decision (D.) 04-12-048. We also order PG&E, SCE, and San Diego Gas & Electric Company (SDG&E) to include in their 2006 long-term procurement plans (LTPP), resource plans that demonstrate whether there is additional system need for new capacity in their service territories in the next four to five years.[2] Based on this additional system need, we will also consider in Phase II of this rulemaking, whether the transitional policies we adopt herein should be extended to additional MWs of new generation. Finally, we note that the Commission is considering capacity markets and multi-year resource adequacy requirements (RAR) in Phase II of R.05-12-013.

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[2] Additional guidance on Phase II plan filings will be forthcoming via a scoping memo.

II. Background

A. Progress Towards Resource Adequacy and Long-Term Procurement

The following overview of our resource adequacy long-term procurement decisions sets the context for the action we take today. In D.04-12-048, we approved the LTPPs and signaled our preference for the IOUs to have a mixed portfolio of resources, including contracts that were short, medium and long term in length. While we authorized the IOUs to enter into long-term contracts, we did not order them to do so. It now appears that long-term contracts are necessary to solicit investment in new generation in California.

The Commission opened this rulemaking in February 2006, as a successor proceeding to previous procurement proceedings, R.01-10-024 and R.04-04-003. In D.04-01-050, considered under R.01-10-024, the Commission required each LSE within the utilities' service territories to be responsible for procuring, under Commission oversight, sufficient reserves to provide reliable service to its customer's load. In that decision, the Commission had considered a proposal suggested by The Utility Reform Network (TURN) to impose a non-bypassable surcharge so that all customers within the utility service territory would pay their fair share of the costs of acquiring needed reserves. TURN's proposed surcharge would have been similar to other surcharges approved by the Commission, such as SCE's Historic Procurement Charge (HPC) approved in D.02-07-032 and the Cost Responsibility Surcharge (CRS) approved by the Commission in, among other decisions, D.02-11-022. TURN proposed to allow ESPs who have acquired sufficient reserves to "opt-out" of paying this surcharge.

Although the proposed decision in this matter had advocated the adoption of the TURN approach, PG&E, SCE, and other parties raised several implementation issues in their comments. These parties' concerns were that

(1) the utilities would be saddled with the cost of acquiring resources for ESPs without the ability to collect from the ESPs, and (2) it would be difficult to procure resources over a longer time-period if ESPs could "opt-out" of the program on a yearly basis. In light of these implementation issues, the Commission modified the proposed decision, and required each LSE to be directly responsible for acquiring its own reserves to meet its own RA obligation.

In R.04-04-003, the Commission implemented the RAR described in D.04-01-050, through the adoption of RA policies and rules. (See, i.e., D.04-10-035 and D.05-10-042 *et seq.*) The Commission currently has a forward RAR that is "year-ahead" in nature. Critics have argued, however, that limiting the RAR to the year ahead creates a potential for resource scarcity. The critics portend, for example, if there is not sufficient capacity to meet all the LSEs' demands, one or more LSEs could be caught short. In this hypothetical scenario, PG&E and SCE fear that an ESP or a community choice aggregator (CCA) unable to meet its RAR because of lack of available capacity will turn back its customers to the IOU. If the entire system is short capacity, then the IOU will be unable to meet its RAR regardless of how well it planned for the needs of its bundled customer load. With a short amount of time between when a shortfall is discovered and when the capacity is needed, no new generation could be brought online in time.

In R.04-04-003, the Commission reviewed and approved the IOUs' LTPPs, and in D.04-12-048, the Commission extended the IOUs' procurement plan authority on a rolling 10-year basis, and authorized the IOUs to enter into short-, medium-, and long-term contracts provided they complete the required compliance filings. In that proceeding, the IOUs expressed considerable concern regarding the stranded costs that might occur if the IOUs invested in long-term contracts and then experienced a large amount of departing load. In D.04-12-048, Section IV.A.2.a, the Commission discussed the stranded costs issue, as well as the fact that ESPs do not have a business model that supports investment in long-term contracts. The Commission concluded that utilities should be allowed to recover their stranded costs from all customers for a period of either the life of the contract or 10 years, whichever is less. (See D.04-12-048, Conclusions of Law 13-16.)

By establishing a year ahead RAR and determining that departing load was required to pay for stranded cost investments, the Commission had good reason to believe that it had removed barriers to long-term contracting. After D.04-12-048 was issued, both SCE and PG&E issued long-term RFOs. However, in Application (A.) 05-06-003, SCE requested cost-recovery for above-market costs from all customers, not just its existing bundled customers. Evidently, SCE needed assurance that already *departed* (not just *departing*) load would pay for the cost of new generation. After issuance of the Scoping Memo limiting the scope of the application, SCE withdrew its application and cancelled its long-term RFO. PG&E continued with its long-term RFO, and recently brought seven contracts to the Commission in A.06-04-012. PG&E has requested similar cost-recovery treatment from all customers for its long-term contracts.

In addition to the fact that SCE has not signed any long-term contracts to promote new generation, since the issuance of D.04-12-048, California has not seen sufficient investment from non-utility sources in new generation. To provide context, the California Independent System Operator's (CAISO) Department of Market Monitoring (DMM) released its assessment of the potential revenues a new generation resource could have earned in California's spot market in 2005. The DMM's April 2006 report indicates that "potential spot market revenues fell significantly short of the unit's annual fixed costs." The DMM looked at costs and expected revenues for both combined cycle and combustion turbine units and concluded that expected revenues do not justify investment in new generation absent long-term contracts:

> The DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2005 indicates potential spot market revenues fell significantly short of the unit's annual fixed costs. This marks the fourth straight year that the DMM's analysis found that estimated spot market revenues failed to provide sufficient fixed cost recovery for new generation investment. This result underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment.[3]

The DMM is very concerned about the effect that the lack of long-term contacting is having on California, particularly in Southern California.

> Though a significant amount of new generation capacity was added to SP15 in 2005 (2,376 MW) and California realized more new generation investment in 2005 than any other ISO (footnote deleted), new generation investment within Southern California has not kept pace with the significant load growth in that region and unit retirements. This has resulted in a higher reliance on imported power from the Southwest, Northwest, and Northern California. This dependence on imports, coupled with tight reserve margins, makes Southern California very vulnerable to reliability problems should there be a major transmission outage. Moreover, much of the existing generation within Southern

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[3] California Independent System Operator (CAISO), *2005 Annual Report on Market Issues and Performance, April 11, 2006*, Executive Summary, ES-2. Available at: http://www.caiso.com/17d5/17d58bdd1270.html.

> California is comprised of older facilities that are prone to forced outages, especially under periods of prolonged operation as occurred during the extraordinarily long heat wave in July, with loads exceeding 40,000 MW for all but two days beginning July 11 and into early August 2005. Additional new generation investment and re-powering of older existing generation facilities would significantly improve summer reliability issues in Southern California but such investments are not likely to occur absent long-term power contracts. The California spot market alone is not going to bring about the major investments needed to maintain a reliable electricity grid.[4]

The CAISO's upcoming Market Redesign and Technology Upgrade (MRTU) is expected to significantly improve the market mechanisms that drive the California's energy markets. It is too early to tell, however, whether MRTU will result in spot market prices and market certainty that will support major investments in new generation without long-term contracts.

The CEC's Transmittal Report for the 2005 IEPR[5] indicated that there were no regulatory barriers to IOU's engaging in long-term contracting. Many parties have stated that the IOUs appear to be the most-likely entities to sign long-term contracts. However, SCE and PG&E state they are unwilling to move forward with long-term contracts if it means that their customers are burdened with the above market costs of those units. TURN has stated that it would be unfair to bundled customers to require the IOUs alone to invest in long-term

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[4] *Id.*

[5] CEC's IEPR Transmittal Report, November 2005, "Commission Final Transmittal of *2005 Energy Report* Range of Need and Policy Recommendations to the California Public Utilities Commission," Publication # CEC-100-2005-008-CMF., December 16, 2005. Available at: http://www.energy.ca.gov/2005_energypolicy/documents/index.html.

contracts if those contracts cost more than existing generation. Numerous ESPs offer a different perspective. They contend that since DA is currently suspended, DA customers are not responsible for load growth, and therefore, no ESP customers should have to pay for any portion of the needed system expansion.

The above events indicate that we need an additional transitional policy to encourage investment in new generation resources now. Today, we address this issue on an interim basis, and we will address it on a long-term basis in Phase II of the RA proceeding, R.05-12-013.

B. Procedural Background

On February 16, 2006, the Commission initiated this rulemaking to integrate procurement policies and consider long-term procurement plans. To ensure adequate contracting for new resources, we invited proposals on ideas for policies to support new generation and long-term contracts. Proposals were received on March 7th and 8th. The Commission scheduled a workshop for March 14, 2006, to discuss the proposals.

The Assigned Commissioner's Ruling on March 29, 2006 permitted parties to comment on proposals discussed and examined at the workshop as well as to offer "new proposals." Comments following the workshop were received on April 10, 2006.[6] Reply comments were received on April 19, 2006.[7]

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[6] Joint Parties Comments including PG&E, SCE, NRG Energy, Inc. (NRG), TURN; The Coalition of California Utility Employees (CUE) and The Californian Unions for Reliable Energy (CURE); and AES Corporation (AES); Joint comments by Indicated Parties that includes California Large Energy Consumers Association (CLECA, California Manufacturers and Technology Association (CMTA), City and County of San Francisco (CCSF), Coral Power, L.L.C. (Coral), Division of Ratepayer Advocates (DRA), Energy Users Forum, J. Aron & Company (J. Aron), Silicon Valley Leadership Group (SVLG) and Strategic Energy, L.L.C. (Strategic); Aglet Consumer Alliance (Aglet);

Footnote continued on next page

III. Summary of Proposals and Comments

The pre-workshop proposals can be grouped into two categories: proposals advocating that the Commission should enact new policies now to support investment in new generation, or proposals suggesting that the Commission should "stay-the-course," to allow other policies, such as resource adequacy and the 2004 long-term procurement plans, which are already in place, to stimulate sufficient new generation.

A. The Joint Parties' Proposal

In advance of the March 14, 2006 workshop, a JPs' Proposal was presented by SCE, PG&E, NRG, TURN, and AES. The JPs argued that the Commission should adopt their cost and benefit proposal as a limited, interim mechanism to ensure that new generation gets built on time. The JPs intend that

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Alliance for Retail Energy Markets (AReM); California Clean DG Coalition (CCDG); CEC; Californians for Renewable Energy (CARE); CAISO; CLECA and CMTA; Cogeneration Association of California and Energy Producers and Users Coalition (CAC/EPUC); Davis Hydro; DRA; Good Company Associates on behalf of TAS (TAS); Green Power Institute (GPI); Independent Energy Producers Association (IEP); Merced Irrigation District and Modesto Irrigation District (MID); Joint Comments of MID, South San Joaquin Irrigation District, Northern California Power Agency (NCPA) and The California Municipal Utilities Association (CMUA) (Joint POU Parties); Mirant California, L.L.C., Mirant Delta L.L.C. and Mirant Potero L.L.C. (Mirant); PG&E; RCM Biothane (RCM); SDG&E; Sempra Global (Sempra); SVLG; SCE; TURN; Western Power Trading Forum (WPTF); and Women's Energy Matters (WEM).

[7] Replies were filed by Aglet; AReM; Indicated Parties; CLECA and CMTA; CARE; California Small Business Roundtable (CSBRT) and California Small Business Association (CSBA); CAC/EPUC; Constellation Energy Commodities Group, Inc., Constellation Generation Group, L.L.C. and Constellation Newenergy, Inc.(Constellation); Davis Hydro; DRA; FPL Energy, LLC. (FPLE); IEP; Joint POU Parties; MID; PG&E; SDG&E; Sempra Global; Joint Parties (same as April 10th); SCE; TURN; WEM.

their interim plan will be replaced by a Commission-adopted market structure that will support new generation investment, such as capacity markets or another durable market mechanism.

The Joint Parties ask the Commission to rule that as a transitional mechanism, the utilities, or another entity if feasible, may procure new generation within an IOU's distribution service territory, with the costs and benefits associated with these new resources allocated to all benefiting customers. Under the JP, "benefiting customers" is defined as all bundled-service customers, DA customers, CCA customers and others who are located or locate within the distribution service territory of an IOU but take service from a local publicly-owned utility (POU) as defined in Pub. Util. Code § 9604(d), subsequent to the commitment date for new generation. Pursuant to D.04-12-048, the JP also propose to recover the net costs of the new generation from Customer Generation Departing Load (CGDL) and Municipal Departing Load (MDL) customers.[8] PG&E filed a separate proposal advocating that the IOUs are the only viable entities than can procure new generation.

Under the JP, not only costs, but also benefits, would be allocated. Capacity and energy are purchased by the IOU as a bundled product through a contract for a new generating unit. All LSEs would be entitled to receive a share of the RAR credit. RA capacity credit would be divided among LSEs by a share of coincident peak, adjusted on a monthly basis to facilitate load migration. Implied in the JP is that the Energy Division (ED) and CEC would distribute the

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[8] Joint Proposal, March 7, 2006, p. 1, fn. 2.

RAR credit through the existing notification mechanisms[9] established in our RA program.

The JPs' proposal is based on the premise that new generation is needed now in order for all LSEs, not just the three IOUs, to meet their individual RAR and to insure system reliability. The JPs argue that the new generation is needed to ensure reliability and allow some aging units to retire, regardless of the source of the load growth.[10] The JPs believe that in order to get new generation financed and built, the investor needs a long-term commitment. While an IOU is an entity with the resources to make such a commitment, PG&E and SCE believe that it would be unfair for their customers to pay the premium that new generation commands as compared with existing resources, while the entire state benefits from such an investment.

Under the JP, both utility-owned generation and power purchase agreements (PPA) for non-renewable portfolio standard (RPS) generation[11] would be eligible for recovery under this mechanism.[12] The JP argues the Commission should not allow an opt-out mechanism for any aspect of the

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[9] Currently, the ED notifies each LSE of its RA obligation, in cooperation with the CEC collaborative staff.

[10] Many ESPs argue that due to the suspension of DA, their customer load is not growing, therefore load growth is by bundled customers only.

[11] RPS eligible generation is subject to cost-allocation mechanisms established in Commission decisions in the RPS proceedings and the JP does not include RPS generation.

[12] SCE indicated that it is only interested in applying this mechanism to PPAs, and to limit the mechanism to a 10-year period. PG&E wants the mechanism to apply to utility-owned generation and PPAs, for the life of the contract and/or asset.

requirement because any opt-out mechanism would require a review of how the LSE was deficient over a multi-year period, which is not currently definable.

The JP envisions the IOU managing the energy contracts and committing and dispatching the energy against forecast market prices in merit order according to least-cost dispatch principles and Commission and CAISO requirements. Any energy not scheduled or experiencing an outage would be submitted to the CAISO consistent with the must-offer obligation of RAR. Then the net cost of this new generation capacity would be determined by adding the fixed cost and variable costs [linked to daily gas index] of the capacity and energy, then subtracting the energy and ancillary services revenues. Then the net costs of just resource adequacy capacity would be allocated to all customers. The costs would be allocated on a 12-month coincident peak among each rate group apportioned to all retail customers on a non-bypassable wire charge (NBC) per kilowatt hour (kWh).

The JP is not meant to be an impediment to a future market structure which may be implemented. The JP proposes that the resources developed under this interim mechanism would be submitted into a future market in a manner which ensures that the benefits and costs are allocated among benefiting customers. The JP anticipates that certain ratemaking issues would need to be clarified in subsequent proceedings. For example, the IOUs would need to be authorized in future Energy Resource Recovery Account (ERRA) proceedings to establish a net cost balancing account. In the case of utility-owned generation, there would have to be separate entries into the Utility Generation Balancing Account (UGBA).

In separate comments supporting the JP, SCE provided schedules for a "fast track" and a "standard track" that it would use to issue long-term RFOs.[13] Under the fast-track, SCE would submit an application by February 2007 for new resources that might come online by 2010. Under the standard track, SCE would submit an application by January 2008 for new resources that might come online by 2012. The purpose of the two-track system is to allow some resources that may already have permits and transmission interconnection studies complete to come online sooner, while also allowing for a wider range of opportunities to bid into the standard track solicitation.

In separate comments supporting the JP, as well as in A.06-04-012, PG&E stated its interest in having the cost-allocation mechanism apply retroactively to all of the new contracts recently selected in its long-term RFO.

B. Other Proposals

In addition to the Joint Parties, 15 other parties submitted pre-workshop proposals.[14] Numerous proposals promoted the concept of "stay the course." Several of the key points raised in the pre-workshop proposals were also raised in post-workshop comments which are set forth in Appendix C. Some key issues from the pre-workshop proposals include:

- Constellation urged the Commission to recognize that the hybrid market structure is part of the problem because it creates an uneven playing field between utilities with

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[13] SCE Proposal, March 7, 2006, p. 14.

[14] Constellation, DRA; WPTF; AReM; IEP; Calpine Corporation (Calpine); Mirant; Sempra; SDG&E; Aglet; California Cogeneration Council (CCC); Davis Hydro; TAS; WEM; and CARE.

guaranteed returns and investors without guaranteed returns.

- DRA urged the Commission to recognize that the uncertainty of customer base is driving the need for cost allocation policies.

- WPTF warned that there are no quick fixes, and it does not see a real urgency for immediate Commission action.

- AReM cautioned that the Commission should continue to support existing RA and LTPP policies. AReM also noted that ESPs cannot be expected to make long-term investments due to uncertainty about the continuation and expansion of DA.

- IEP argued that the Commission is asking the wrong question. According to IEP, cost allocation proposals are not the solution to the problem of lack of investment in new generation. Rather, it is the lack of regulatory stability and rules. IEP urged that the Commission should require all-source solicitations (that do not exclude existing resources) and improve the RFO and evaluation process to ensure fair and equal treatment.[15]

- WPTF, IEP, Sempra Global, Mirant, and SDG&E are among those that argued that the Commission should move on immediately to implementing a capacity market in R.05-12-013.

- SDG&E argued that new policies are not required, since SDG&E was able to build new generation.

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[15] The Commission is planning on addressing RFO procedures in Phase II of this proceeding.

- Aglet suggested the Commission order the utilities to build new generation.

- CCC urged the Commission to adopt a Combined Heat and Power portfolio standard.

- Davis Hydro suggested the Commission should adopt proposals to enable pent-up demand for green power.

- TAS urged Commission to approve contract plant expansion using Turbine Inlet Cooling technology to expand capacity.

- WEM suggested the Commission prioritize new energy efficiency programs before adopting policies that support fossil resources.

- CARE supports a return to the IOUs making investments in new generation, along with entering into long-term contracts, but asks the Commission to ensure that the cost burdens for the new generation do not fall unfairly on the bundled ratepayers.

C. The Indicated Parties' Proposal

At the workshop on March 14, 2006, another proposal was introduced as the "Investco plan." The Investco plan responded to and modified the JP so that the entity that would procure the new generation would still be an IOU, but that the capacity and energy would be separated into two contracts. The Investco entity would assume the energy risk along with the tolling rights for a 10-year term. The IOU would hold an RFO and select a contract for a PPA tolling agreement. The entire contract would be unbundled to split it into these two components – the 10-year resource adequacy counting rights held by the IOU and a 10-year energy tolling contract held by the Investco entity.

The Investco plan was further modified by the Indicated Parties (IP)[16] and renamed the Distco plan in post-workshop comments.

The Distco plan's recommendation, as presented by the IPs, is predicated on the IPs belief that if the Commission must do something to get new generation built, the JP as proposed is not satisfactory. The Indicated Parties fault the JP because it only addresses the need for reliability, but fails to ensure that the energy component of the backstop resources is managed in the most efficient manner possible. The IPs are concerned that the JP forces all energy from the new plants to be valued at the spot market prices over 10 years. To address this deficiency, the IPs state that the IOUs must unbundle the capacity and the energy from any new generation project, consistent with the Commission's encouragement of resource adequacy unbundled products, as well as attempt to optimize the energy value through an auction process. Pursuing a forward contracting model for the energy revenues will minimize customer exposure to spot market prices.

Among other modifications to the Investco model, the Distco plan provided for an annual or multi-year auction for the tolling rights to the energy rights of the plant for a term of up to five years (instead of selling it all at once for the full 10 years), and it allowed utilities to participate in the auction. These modifications addressed the concerns raised at the workshop that no entity might be interested in buying a 10-year tolling contract for the energy, as proposed by the Investco model.

[16] The Indicated Parties included CLECA, CMTA, CCSF, Coral, DRA, Energy Users Forum, J. Aron, SVLG and Strategic.

Specifically, under the Distco plan, PPAs would be eligible resources that could bid into a utility solicitation process for new resources. Once chosen, the net RA capacity costs (total project costs minus the energy revenue benefits) from the project would be socialized to all utility customers through a non-bypassable wires charge just like the JP. Under the Distco plan, however, the IOU would not manage the energy dispatch process and only credit all customers with spot market revenues. Instead, the IOU would conduct an annual or multi-year auction that would allow market participants to bid on the energy component of the contract.[17] Utilities' procurement departments would be allowed to participate in the auctions on behalf of bundled customers. If no bids were received, or if no bids were received that exceeded a minimum threshold, the default would be for the IOU to manage the energy dispatch and revenues in accordance with the terms of the JP. If an acceptable bid was received for the energy for a term of one or more years, then the net cost of the RA capacity (which is spread to all customers) would be fixed for the term of the energy contract.

The IPs believe a principle benefit of their Distco plan is the fact that the IOUs are not "managing the energy" and potentially using the large volumes of energy to flood the energy markets. The costs of the new capacity are spread to all customers, and the benefits of the energy are paid for by those who value the

[17] The winning bid would receive an Energy Conversion Agreement at a fixed price of $/kW month and have the right to toll the unit as desired. The Resource Adequacy "counting" right would be retained by the IOU, to be credited as "RA capacity" to all customers that pay for the capacity.

energy the most, which in turn minimizes the net cost of the capacity that is born by all customers.

D. Post-Workshop Comments

In general, the comments can be categorized into three groups: those urging the Commission to act now to effectuate new generation for California; those advocating that the Commission "stay the course"; and those recommending that the Commission do nothing now, but making suggestions in case we do. Post-workshop comments are summarized in Appendix C.

IV. Adoption of Modified Proposal

A. Discussion

We have carefully weighed the cogent arguments presented at the workshop and in the comments that urge the Commission to promote regulatory certainty in California by enforcing the policies already in place, i.e., the resource obligations and planning directives established in our earlier decisions. In particular, we have established RAR for all LSEs,[18] we authorized the IOUs to procure consistent with their LTPPs and we authorized cost recovery accordingly for 2005 through 2014.[19] In addition, to address concerns for burdens on bundled customers from migrating customers, we allowed the IOUs to recover stranded costs from all customers for a 10-year period. When D.04-12-048, the RAR decisions and AB 57 are read in concert, the IOUs have no barriers to either building new generation or entering into long-term contracts for new generation. Yet, despite all the steps the Legislature and this

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[18] See D.04-10-035, D.05-10-042 *et seq.*

[19] D.04-12-048.

Commission have taken to see that the state has adequate electric resources, it is clear that there is a need for new generation as early as 2009.

We are, however, concerned that if we jump too quickly into taking steps that appear to be protecting IOUs from any risk in investment in new generation, it could be interpreted as signaling an end to a hybrid electricity market in California. SVLG warns us of policy changes towards reintegration. In that climate, there is little potential for any non-utility to invest in new generation resources for California. We recognize that granting the IOUs too much price guarantee and risk protection, may undermine the development of a more competitive market.

IEP and WPTF caution us that there are no quick fixes, and they would prefer that we address problems with the IOUs' RFOs that exclude existing generation from bidding instead of adopting a new proposal. SDG&E also does not think we need any new policies since they were able to get new generation built. However, we note that SDG&E's new resources are partially supported through reliability-must-run (RMR) contracts, which is slightly different, yet analogous to the JP on cost shifting principles. This Commission has stated its preference to moving away from RMR, rather than perpetuating it.

Aglet and other parties suggest that the Commission just order the utilities to build new generation. While it is well within the Commission's legal authority to order the utilities to build without cost-allocation treatment, we do not expect that strategy will likely yield new generation by 2009.

CMTA/CLECA argue that we should investigate whether the IOUs have "complied" with our orders in D.04-12-048. But as TURN noted, it is more important that the Commission figure out how to ensure new generation needed for system reliability gets built when it is not in the interest of any LSE or its customers to take on such an obligation.

While we find these arguments well thought out and presented, we are still faced with a real scarcity issue. We must therefore make a careful analysis of what is at risk: if we do nothing, we could be putting the state in jeopardy of being short the generation facilities needed to assure adequate capacity and energy as early as 2009, or we could take the initiative now to promote new "steel in the ground" and take the chance that some will question our commitment to competition and customer choice. Allowing the fear of risks to create a stalemate, however, does not ensure that new generation will be built in the necessary timeframes needed by California.

Therefore, to assure grid reliability for the state as a whole, we adopt a plan to remove many of the remaining risks or barriers, perceived or real, to investment in new generation. We do not do this enthusiastically, but from necessity. Our ultimate goal is a robust and competitive wholesale market and a competitive retail market. Until that is a reality, we adopt an interim plan to encourage new generation. We intend this to be a short-term solution.

B. The Adopted Proposal

The interim proposal we adopt below contains the skeleton of the JP, as modified. We revised the JP to avoid some of the problems cautioned by those advocating the "stay-the-course" position.[20] We accepted some of the revisions

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[20] In particular, we found the suggestions made by CLECA, CMTA, CCSF, Coral Power, DRA, EUF, J. Aron, SVLG and Strategic Energy, along with Sempra to be persuasive and adopted many of the modifications to the JP advanced in their comments.

offered by the Indicated Parties, and then added further adjustments as suggested by the parties at the workshop and in their comments.

1. We adopt the provisions of the JP that the Commission designates an entity to procure new generation within an IOU's distribution service territory, with the costs and benefits associated with development of these new resources allocated to benefiting customers.[21] We designate the IOU as the entity to procure new generation, until modified by Commission decision. The LSEs in the IOU's service territory will be allocated rights to the capacity that can be applied toward each LSE's RAR requirements. The LSEs' customers receiving the benefit of this additional capacity pay only for the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract.

[21] Benefiting customers are defined as all bundled service customers, DA customers and CCA customers. Benefiting customers are also other customers who are located within a utility distribution service territory, but take service from a local POU subsequent to the date the new generation goes into service.

2. New generation approved by this Commission and eligible for the cost allocation mechanism will receive cost recovery for a period of up to 10 years. We limit the maximum term of any cost paid by all customers to the term of the contract, or 10 years, which ever is less, from the time that the new unit comes online.

3. We intend this cost allocation mechanism to be in place for the term of the contract or up to 10 years, whichever is less, from the time the new unit comes on line. However, the mechanics of this cost allocation mechanism may charge depending on the new market-based system which may evolve.

4. We determine that the administrative cost of selecting the contract (i.e., the procurement administrative costs for contract negotiation and selection) will be born by only the bundled customers, because there is no way to easily separate out these costs. Furthermore, these costs are intermingled with the rest of the IOU's procurement activities. While these costs may be a slight burden on the bundled ratepayer—relative to the cost of the contract and the magnitude of the analysis required to unbundled the cost of contract selection from the cost of the contract—we find that it is reasonable to make this determination.

5. As previously determined in D.04-12-048, all currently bundled customers are responsible for any long-term commitments entered into by the IOUs for 10 years, unless otherwise modified by the Commission. Nothing we adopt herein relieves or adds to that responsibility. Contracts ineligible for this cost allocation mechanism, or contracts to which the IOU elects not to apply this cost allocation mechanism at the time it seeks Commission approval of the contract, are still subject to the rules of D.04-12-048. Numerous parties representing potential IOU departing load weighed in to this proceeding to

argue that their customers should not be responsible for new resource commitments. In D.04-12-048, we already determined that future departing load is responsible for the resource commitments entered into by the IOUs on their behalf whilst they are still bundled customers.[22]

6. The IOUs are required to administer a competitive solicitation and select new resources for long-term contracts. We direct the IOUs to utilize a third-party independent evaluator (IE) to oversee any competitive RFO that produces a contract subject to this cost allocation mechanism. We continue the requirement that the IOUs must bring any contract to the Commission for approval via an Application if the contract is greater than five years, and be subject to other procedural rules such as oversight by the procurement review group and the IE. We do not expect that any contract for new resources would be for less than five years; however, we will only allow contracts brought to the Commission for approval via an Application to be considered for the cost-allocation mechanism adopted here.

7. Each IOU may fill its new generation need by way of a competitive RFO, which is open to any fuel type or technology from both green sites and repowered brown sites.[23] In D.04-01-050, we strongly encouraged repowering if possible, and we continue to believe that repowered projects are beneficial. We do not explicitly require IOUs to give preference to repowerings, but we expect that IOU RFO evaluation procedures will value

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[22] See D.04-12-048, Conclusions of Law 13-16.

[23] In comments, parties representing other resources, such as co-generation facilities, wanted further clarification that all-source solicitations could also include co-generation as well as renewables sources. All-source means "all source," and we see no need for further elucidation at this time.

the economic benefits of repowering. The IOUs should be flexible with the on-line dates (including in SCE's fast track solicitations) so that potential viable resources, especially repowered sites, are not excluded if there is a short gap in which an existing power plant continues to produce power, before the new plant gets built and comes on-line.[24]

8. IOUs are encouraged to hold all-source solicitations to select long-term contracts but only new or repowered facilities of any resource type are eligible for the cost-allocation mechanism.

9. If the utility signs a "hybrid" contract which includes some years of service from an existing unit, and some years of service for a new unit on the same or on a near site—the cost-allocation method adopted herein only applies to the part of the contract with the new facility. Any part of the contract that uses the existing facility must be paid fully by bundled ratepayers.

10. We do not prohibit the utilities from owning their own generation, nor building their own power plants. However, we concur with Mirant, Sempra, AReM and other parties that recommended we not allow utility-owned generation to qualify for this cost-benefit allocation mechanism. We do not allow resources chosen

[24] Numerous parties have complained to the Commission that the IOUs are designing their RFOs to specifically exclude certain bidders, in particular existing resources. It is our intention to address RFO procedures in Phase II of this proceeding, but in the interim, our guidelines from D.04-12-048, Section VIII(D) are to be followed. We specifically stated "all resources (IOU-built, Turnkey, Buyout and PPA) must participate in an all-source or RPS solicitation. However, the IOUs have the flexibility to tailor their RFOs to reflect their specific resource needs." (Page 128.)

by the IOU that are utility built or utility owned[25] to be eligible for this cost recovery mechanism. As many parties noted, there are numerous long-term energy benefits to utility-owned generation, and it is difficult to isolate just the first few years worth of capacity value of a 30-year or longer utility-owned asset. We recognize that this determination affects PG&E the most because (1) SCE has already stated that it will only consider PPAs in its future LT RFOs and (2) PG&E has already selected two projects that will be utility-owned projects.[26]

11. Each IOU may fill its new generation need with resources that are within or outside of the CAISO's identified local reliability areas. However, given that all LSEs are expected to have local RAR as a result of the decisions in Phase I of R.05-12-013, we encourage the IOUs to give strong consideration, if not outright preference, to resources that reduce the local RAR for all LSEs. If a new unit subject to the cost-allocation mechanism falls within a local area, the local RA counting benefit will also go to all LSEs that are paying for the resource. The IOU should justify why any new contract procured on behalf of the entire system does not address local RAR.

12. On the subject of contract confidentiality and disclosure, we defer to the outcome of the Confidentiality proceeding, R.05-06-040 and D.06-06-066. Numerous parties requested that we find that all contracts subject to this cost allocation mechanism be deemed public. We do

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[25] The utility may participate in the all-source RFO, and may be a winning bidder. The restriction is only on having the costs of a utility built or owned resource recovered under the cost allocation mechanism adopted today.

[26] In A.06-04-012, PG&E requests Commission approval, among others, for the following two contracts: a Purchase and Sale Agreement (PSA) with E&L Westcoast Colusa, and an Engineering Procurement and Construction (EPC) contract with Wartsila Humboldt.

not make that determination here because the Confidentiality proceeding is already considering closely related matters.

13. We find that IOU conduct in RFOs (i.e., RFO processes) are not the subject of this decision. However, we reiterate our commitment to review RFO processes in Phase II of this rulemaking.

14. We find that the energy and capacity from any new resources should be unbundled, with the costs and benefits of the RA capacity component socialized to all customers connected to the utility's distribution system, and the costs and benefits of the energy component assigned to those that value the energy the most, as demonstrated through an auction or similar mechanism.

15. The IOU should charge the benefiting customers the net cost of capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the total contract. All RA counting benefits and net costs are spread to the LSEs whose cutomers are allocated costs based on share of 12-month coincident peak, adjusted on a monthly basis to facilitate load migration. The contract costs paid and RA benefits received by DA (or CCA and muni load) and bundled customers should be based on a share basis equal to the credit share received.

16. We agree that the energy component of the contracts for new resources can be managed by an IOU. However, as recommended by the Indicated Parties, we chose to separate the energy component so the risks can be assumed by individual market participants. We require that each IOU must file an Implementation Proposal for Commission approval in the LTPP proceeding (or a separate proceeding if notified by the Commission) for how it will plan to conduct periodic auctions, for the

energy rights for each of the resources acquired under this interim proposal. These auctions will provide the right for another entity to manage the energy component of the contracts. Essentially the IOU will sell the tolling right, and retain the RA benefit which it will share with all customers paying for the capacity. The IOUs must retain an independent third party to administer the energy auction. The auction will be overseen by the IOU, the procurement review group and the third-party evaluator. The cost of administering the auction shall be considered part of the IOU's procurement expenses unless the IOU contracts with a third party, in which case, the cost of the auction shall be considered part of the cost of the contract. The IOU's own procurement group will be allowed to bid on the auction for the energy. The purpose of the auction will be to maximize the energy value and minimize the residual cost of the RA capacity. The auctions should be periodic, so as to capture the fluctuations in the energy market. If there are no bids accepted for the tolling right to the contract, then the IOU will manage the energy dispatch in accordance with the original terms of the JP, i.e., it will be valued at spot market prices, until time for the next periodic auction, or one year, whichever comes first. The Commission's Energy Division (ED), in consultation with the Assigned Commissioner, shall hold a workshop prior to the IOUs' filing their Implementation Proposals, and subsequent workshops as needed.

17. The IOU's Implementation Proposal filed with the Commission must include a proposal for how the RA credit and costs will be calculated and allocated. The IOU proposal will include how it will notify all LSEs, the Commission's ED, and the CEC of the amount of RA capacity that is expected to be available and when. As part of the normal notification of RAR, the ED and CEC could provide each LSE with a credit that it can use towards either its system RAR compliance showing, and if applicable its local RA showing. The IOU is obligated

to auction the rights to the energy, unless the Commission directs otherwise.[27]

18. The ratemaking mechanisms to implement this cost proposal will be addressed in Phase II of this proceeding as well as in proceedings for each IOU's general rate cases and other relevant proceedings.

19. If an IOU identifies and selects a new power plant project outside of a competitive solicitation, i.e., through a "unique fleeting opportunity" ("UFO") such as Mountainview or Contra Costa 8, that "UFO" is ineligible to be considered for this cost-allocation treatment. Such opportunities must be weighed on their merits for currently bundled customers only.

C. Other Issues

1. Other Market Participants

We encourage other market participants to develop new generation in California, even without long-term contracts with IOUs. Nothing we do today prohibits IOUs (or ESPs) from contracting with other new resources that come online without the aid of long-term contracts with the IOUs. It is our expectation that as MRTU, and other market mechanisms evolve—investors will find it attractive to invest in California's energy market even without long-term contracts. In fact, we may find that the State has underestimated its forecast for future demand growth in the outer years, and if higher demand growth comes to pass – additional new resources may be needed by all LSEs even to satisfy their RAR. Additionally, we know that we are unable to predict retirements of aging

[27] In the draft decision, the IOU could determine that it no longer wanted to auction the rights to the energy. In response to comments, that option has been removed.

power plants, which may also change the supply/demand outlook. While many have stated that new power plants require long-term contracts—we remain open to the possibility (and indeed hopeful) that eventually some power plants may be built without long-term contracts from IOUs. For example, WPTF cited a new power plant that is being developed by GE and Calpine in Romoland, CA. Although this power plant is not yet included in the CEC's supply forecast due to the early stage of its construction, we find this news encouraging in that it portends the development of non-IOU sponsored new power plant investment. We will revisit the IOU's LTPPs in Phase II and biennially thereafter, and if we find that additional power plants are coming on-line (or retirements are not imminent), we will readjust our directives to the IOUs.

2. Public Good

We reject the Joint Parties characterization that the new resources constitute a "public good." To do so raises many legal and political issues that may actually prove to be impediments to our going forward with our decision. We are confident that the proposal as set forth below is based on sound legislative and Commission authority and precedent and does not need the designation as a public good in order to support the cost-allocation methodology we adopt.

3. Future Extension of Mechanism

We find that important goals for Phase II of this Rulemaking will be both to examine bundled customer need, as a repeat to the 2004 LTPP, and also to look carefully at the bundled customer need in the context of regional system need. We will review the need for new system resources in each IOU's territory and we may find that it is prudent for the IOUs to add additional resources to benefit the entire system. If so, we may authorize a continuation of the transitional mechanism to cover the next round of contracts.

4. Opt-Out Mechanism

We find that the concept of an opt-out mechanism to this cost and resource adequacy benefit allocation methodology is appealing, but we are unable to adopt such a plan today. While we would like to agree with WPTF, Sempra and others and say that "any LSE that can demonstrate that it is fully resourced with new generation for the 10-year time frame may opt-out of the cost allocation mechanism," the reality is that we have no viable enforcement program or mechanism for doing so. We do not currently have a multi-year RA program wherein an LSE could demonstrate it is fully resourced for the next four or 10 years. A forward looking RA showing that allowed LSEs to list "new" resources for three to four years out might be based on "expected" online dates, and would not be enforceable. Another version of an opt-out mechanism proposed by Sempra would be an extension of the RAR that would require all LSEs to demonstrate that a portion of their resource portfolio was sourced by new resources. We will defer an opt-out mechanism to Phase II of R.05-12-013, where we will consider it concurrently with capacity markets and multi-year resources adequacy.

We will determine at that time whether it is possible to allow an opt-out mechanism to apply to contracts that have already been approved to be covered by this cost allocation mechanism, or whether it can only apply to future RFOs, as of the time adopted. The latter case is supported by the JP, but we decline to make that determination without full knowledge of the nature and scope of the opt-out mechanism.

5. Need Determination

We reaffirm the already established immediate and urgent need for new resources. This is not, however, an exact science and we heed the cautions proffered by so many parties that if we are going to take this bold interim step, that we not use over-inflated estimates of need, but use conservative estimates until a record supports a larger increase. We will proceed using the need numbers from our last LTPP decision, D.04-12-048, and/or the numbers further supported by the CEC's 2005 IEPR. At the time of the LTPP filings in 2004, SDG&E had no need for more long-term resources within the referenced time frame. When PG&E, SCE and SDG&E file their 2006 LTPPs, they will have the opportunity to propose, and support, new need assessment numbers.

The CEC and the CAISO both participated in a discussion of the need determination issues at the workshop on March 14, 2006. Both the CEC and CAISO concur that there is an urgent need for new resources in South of Path 15 (SP-15). The need for new resources in North of Path 15 (NP-15) is driven by both load growth, as well as expected retirements.

In D.04-12-048, we determined that SCE[28] and PG&E[29] should continue to fill their net short with short-, medium-, and long-term contracts. In

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[28] D.04-12-048, OP 5 states, "We find that SCE's LTPP resource plan is reasonable, subject to the compliance requirements covering its demand forecast, demand response, energy efficiency and other factors set forth in this decision and other Commission decisions in those designated proceedings. SCE has demonstrated that its primary residual resource need through 2011 is for peaking, dispatchable and shaping resources. SCE has considerable need for peaking and shaping resources, which should be obtained through short-, medium- and long-term acquisitions. SCE's strategy of relying primarily on short- and mid-term contracts during this planning period is reasonable, but it may be prudent to add some long-term resources. SCE is authorized to present

Footnote continued on next page

that decision, we found that it would be prudent for PG&E to add new long-term resources – and we specified that 1,200 MW of new peaking generation, and 1,000 MW of new peaking and dispatchable generation in 2010 was needed. We left open the opportunity to PG&E to justify slightly higher amounts.

We find that it is not necessary to revisit in this decision our previous need determination for PG&E since we already authorized PG&E to justify additional resources, above the 2,200 MW, when it brings in its Application following a RFO.[30] Although our determination for 2,200 MW was based on PG&E's bundled customer need, not entire system need, we do not find it necessary to revise the need determination number at this time since we will revisit need determination in Phase II.

In D.04-12-048, we did not specify a precise amount of new resources for SCE, since SCE believed it was "long" on long-term contracts due to the number of Department of Water Resources (DWR) contracts in its

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such a case to the Commission as an implementation of its LTPP by way of an application following a RFP."

[29] D.04-12-048, OP 4 states, "We find that PG&E's LTPP plan is reasonable and we approve PG&E's strategy of adding 1,200 megawatt (MW) of capacity and new peaking generation in 2008 and an additional 1,000 MW of new peaking and dispatchable generation in 2010 through RFOs because it is compatible with PG&E's medium resource needs, does not crowd out policy-preferred resources, and is a reasonable level of commitment given load uncertainty. Those commitments may need to be increased or expedited for PG&E to meet its 2006 resources adequacy obligations. Depending on the nature of the bids obtained, PG&E is authorized to justify to the Commission why higher levels might be desirable. Nothing in this decision precludes PG&E from offering local reliability contracts, should they become necessary, pursuant to D.04-10-035."

[30] PG&E filed A.06-04-012 in April 2006. Included in that application was a request for approval of 2,250 MW of new resources.

portfolio. However, we left it open to SCE to return to the Commission with an application for new long-term contracts. In SCE's filing in this Rulemaking on March 7, 2006, it indicated a willingness to procure up to 1,500 MW of new long-term contracts on behalf of all benefiting customers. SCE indicated it would launch a two-track system for its LT RFO. SCE's first long-term RFO would be on a "fast track" with an expected online date of mid-2009, and SCE's second long-term RFO would be on a "standard track," with expected online dates of 2012-2013.

Attached in Appendix A and B are excerpts from the CEC's Integrated Energy Policy Report (IEPR) Transmittal Report and the CEC Supply and Demand Five Year Outlook. The CEC's IEPR Transmittal Report was developed in November 2005 and is intended to provide recommendations to the CPUC for use in the 2006 procurement and related proceedings, including developing and documenting the range of need for the three largest investor-owned utilities. Following the format of the 2004 procurement proceeding, the CEC's Transmittal Report focuses on the contractual needs of the IOU's bundled customers, although it can be combined with the CEC's Supply and Demand Five-Year Outlook on system needs to better understand system need by IOU territory. In the text of the Transmittal Report, the CEC urges significant use of new long-term contracts (signed by the IOUs) to allow for 14,000 MW of aging power plant replacement statewide.

The CEC analysis for SP-15 shows a need for new resources almost immediately. The CEC analysis for SP-15 includes both SCE and SDG&E territories, and we would prefer that future CEC analysis of the need for system resources in SP-15 be split into the SDG&E and SCE territories, consistent with our procurement paradigm. We would also prefer to have a better understanding of whether the future resource requirements are located within or outside of the region's local load pockets, as identified in the CAISO's Local Reliability Analysis studies. Regardless of which load pockets the SP-15 need is in, as shown in Appendix B, Slide 2, the CEC identifies the need for about 1,783 MW of new resources by 2010 to avoid a Stage 1 emergency situation (7% reserve margin) during adverse conditions (which includes a 1 in 10 load forecast). The planning reserve margin under normal conditions is 22.7% in 2006, and reduces to 15% by 2010. However, the adverse scenario reserve margin is only 2.4% in 2006, and is –5.5% by 2010. The adverse scenario reserve margin is very low. The figures presented above do not incorporate the CEC's revised (upward) 2007 demand forecast which we expect will further worsen the outlook for planning reserve and adverse scenario reserve margins. All of the CEC analysis assumes no additional retirements in SP-15 before 2010. In all likelihood, the state will need more than 1,783 MW in SP15 to allow for retirements, ensure against execution and plant building risk, and maintain at 15%-17% planning reserve margin and adequate adverse condition reserve margin. We recognize that SP-15 is neither the sole responsibility of SCE nor SDG&E, and we currently understand SDG&E is under contract to add new resources to SP-15 in the 2009 timeframe (i.e., Otay Mesa).

Based on the CEC's 2005 IEPR, which is supported by other data submitted by these parties in this rulemaking, we find that we can repeat our determination from D.04-12-048 that SCE is allowed to bring to the Commission an Application for new long-term resources. We further find that SCE's needs to procure at least 1,500 MW of new resources by 2009-2010, and that this finding is very conservative given the IEPR Transmittal Report and CEC's Supply Demand Outlook in SP-15. As with our order to PG&E in 2004, we leave it open to SCE to justify more MW, either in its application for approval of the contracts, or preferably in the Phase II of this docket.

For both SCE and PG&E, we urge the utilities to consider to be mindful of the need for resources that address the need for local reliability, as discussed in Phase I of R.05-12-013. In that docket, we are in the process of implementing local RAR. To the extent that the IOUs are going to procure new resources on behalf of all customers, we expect that they will give high priority (if not outright preference) to resources that meet local RA obligations. The IOUs should justify why any new contract procured on behalf of the entire system does not address local RA requirements.

6. Legal Authority

In conjunction with their JP, the Joint Parties provided legal support for their cost-allocation scheme citing AB 380, codified as Section 380 in the Public Utilities Code, for the Commission's authority to approve the plan. The applicable section of the code is as follows:

> An electrical corporation's costs of meeting resource adequacy requirements, including, but not limited to, the costs associated with system reliability and local area reliability, that are determined to be reasonable by the commission, or are otherwise recoverable under a procurement plan approved by the commission pursuant to Section 454.5, shall be fully recoverable from those customers on whose behalf the costs are incurred, as determined by the commission, at the time the commitment to incur the cost is made or thereafter on a fully non-bypassable basis, as determined by the commission.[31]

[31] Cal. Pub. Util. Code § 380(g).

In summary, Section 380 allows an IOU to recover the costs it incurs to sustain "system reliability and local area reliability" from all customers "on whose behalf the costs are incurred." We construe benefiting customers as defined in Section IV.B.1 as those customers on whose behalf the costs are incurred.

Joint Parties posit that the Legislature's intent is clear from the statutory language that they did not want to limit recovery for system and local area reliability to just an IOU's bundled customers, but authorized recovery from a larger group of customers. Therefore, Joint Parties argue that the JP is consistent with the Legislative intent of AB 380 since it provides for an equitable cost allocation for the new capacity needed for system reliability from all benefiting customers.

We agree with the Joint Parties that Section 380 clearly authorizes the Commission to adopt a cost-allocation methodology that spreads the cost of new generation. In addition, we read Section 380 as mandating that as part of the Commission's obligation to establish RAR that we must support "new" generating capacity and equitably allocate the costs. The pertinent portion of Section 380 that addresses RA is as follows:

> (b) In establishing resource adequacy requirements, the commission shall achieve all of the following objectives:
>
> (1) Facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed.
>
> (2) Equitably allocate the cost of generating capacity and prevent shifting of costs between customer classes.

While we have adopted RAR for all LSEs, we have not specified that any portion of the capacity must be "new." Sempra, in its comments, points this out, and this may be an area that we address in the future. In the interim, the cost-allocation methodology we are adopting in this decision is intended to support new generating capacity.

To further bolster their claim that the cost allocation proposal in the JP is consistent with law and Commission precedent, the Joint Parties reiterate the Commission's mandate that rates it imposes must be "just and reasonable" and cannot be unfair or discriminatory. The Joint Parties cite to a number of cases where the Commission imposed recovery surcharges upon benefiting customers when costs are incurred by the IOU for the benefit of all customers, not just for its bundled-service customers.[32]

More recently, in D.04-12-048, the Commission found that it was appropriate and reasonable for the IOUs to recover the net costs of long-term commitments from all customers, including departing customers.[33] As a corollary to that finding, the Commission allowed the IOUs to recover costs related to enhancing reliability from all customers in their respective service areas who benefit from the reliability, not just from those taking bundled service.[34]

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[32] Joint Parties Proposal, March 7, 2006, p. 13, citing D.02-11-022(addressing charges for direct access customers); R.03-09-007 (addressing charges for CCA); D.03-04-030 (addressing charges for distributed generation departing load); D.03-07-028 (addressing charges for municipal departing load) and D.05-12-041 (addressing charges for CCA).

[33] D.04-12-048, pp. 58 -60.

[34] *Id.*, at 63.

Joint Parties also point to the "physical interconnectedness of California's electricity system."[35] From their perspective, it is not the sufficiency of the largest entity's resources that ensures reliability, as much as it is the sufficiency of all entities' resources. Since a fully resourced LSE can be subjected to an outage because of an under-resourced LSE, all LSEs benefit, and all LSE's customers benefit from new generation that contributes to system reliability.

We agree with the Joint Parties that Section 380 supports the adoption of the cost allocation formula set forth herein, and in addition, we read Section 380 as mandating that we take proactive steps to facilitate new generating capacity and the cost sharing mechanism we prescribe is the appropriate way to equitably allocate the cost and keep rates just and reasonable.

7. Affiliate Transactions

Sempra and other parties requested that the Commission limit the applicability of this cost allocation mechanism to non-affiliate transactions. It was only in D.04-12-048 that the Commission lifted the ban on affiliate transactions. Although we are sympathetic to the concerns of parties that fear the IOUs will just use this cost-allocation mechanism to support affiliate projects, we are committed to being vigilant against affiliate abuse issues. We established an IE process in D.04-12-048 for the RFO process to protect against affiliate preference, and we do not yet have evidence in the record that would cause us to not trust the IE process. By this decision, we further require the IOUs to use an IE to oversee any RFO that produces a contract subject to the cost allocation mechanism.

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[35] Joint Parties' Comments, April 19, 2006, p. 3.

Therefore, we do not find it reasonable to reverse course and limit this cost mechanism to non-affiliate transactions. We caution the IOUs to make sure their contract evaluation and selection procedures are above approach and we urge the IOUs to provide information about their bid selection process to as broad an audience as possible.

8. Market-Based Approaches

We are mindful of the optimism shared by several parties that a functioning, centralized capacity market will create the proper market signals to promote investment in new generation in California. While we adopt the cost-allocation methodology set forth herein, and a process for determining the mechanics of the methodology, we are hopeful that a market-based approach, such as a functioning, centralized capacity market, or satisfactory alternative, is in place soon. However, out of a need to ensure that new generation does get built, we adopt a cost-allocation methodology that is designed to provide an incentive for investment now.

We are forging ahead towards a market-based approach. However, a functioning new market, whether it is a capacity market or another market institution, takes time to design and implement as evidenced by models from other states and regional systems. Once implemented, a new market may take time to yield its desired policy results. For example, it is not yet clear that capacity market models in place in the eastern markets have yielded new generation investments. Therefore, we find that until there is a functioning market-based institution in California, we must use a transitional mechanism in order to ensure sufficient new generation for California.

Many parties indicated in their comments that they favored some form of a capacity market, not just to stimulate new generation, but also to insure that the energy costs are paid by those who need and value the energy. We note that under some capacity market design proposals, the cost of new generation is borne by all customers if there is a determination that there is a forecasted capacity shortfall in the system.[36]

The Commission signaled its interest in researching and examining capacity markets when it issued a staff white paper on capacity markets in August 2005 and invited comments on the paper.[37] Those comments indicated a wide range of views on how to move forward with the design and implementation of capacity markets. In December 2005, the Commission opened R.05-12-013 to consider both local RAR, Phase I, and capacity markets-along with multi-year RA and other issues-in Phase II. Therefore, the issue in this Rulemaking is limited to what the Commission should do in the intervening time to support new generation investments in California.

9. Non-Utility ESP

Although the future state of the retail market is not within the scope of this proceeding, it is worth mentioning here that this cost-sharing plan should make the IOUs indifferent to the reopening of DA once the legacy of the DWR contracts expire. If DA customers are participating in the cost allocation plan, then there will not be a cost differentiation based on the cost of capacity of new

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[36] Under some capacity market design proposals, the CAISO would be responsible for contracting for new generation resources and spreading the costs to all customers, if it was determined that there was a forecast capacity shortage in the four-year ahead time frame. Under some models, the capacity authorized today as eligible to receive cost-allocation treatment may be seamlessly folded into the new mechanism; however, it is impossible to determine now if that will be the case.

[37] The Capacity Markets White Paper was issued in R.04-04-003.

generation between the price the IOUs charge their bundled customers and the price DA can offer. However, if the IOUs have to pass on the entire cost of the new generation to just their bundled customers, with no wider cost allocation scheme, then the cost of energy from an IOU will necessarily be more expensive that that from a competing DA provider. Because the non-utility LSEs do not have RAR requirements that necessitate them entering into long-term contracts, the non-utility LSEs would not have to pay the price of a contract for new generation. This situation will create an unacceptable inequitable balance between IOU bundled ratepayers and other ratepayers. However, under our new cost-allocation proposal, there will be no “free riders” vis-à-vis the cost of capacity of new generation, and the IOU’s bundled customers will not be solely responsible for the costs of new generation that benefits the system as a whole.

10. PG&E’s Situation

PG&E is in a unique position. The Commission just approved[38] a settlement agreement for the procurement of the CC8 facility that will be a PG&E-owned resource with a capacity of 530 MW. In addition, PG&E completed a long-term RFO pursuant to the need identified in the 2004 LTPP, and has contracts for an additional 2,250 MWs. Sempra and other parties argue that we should not allow this cost-allocation mechanism to apply “retroactively” to the PG&E long-term RFO. We disagree with Sempra, and we will allow PG&E to designate up to 2,250 MW of new generation that is not utility-owned from the recent LTPP RFO to be eligible for the cost-allocation methodology established in this decision. CC8 is not eligible for the cost allocation mechanism since it is a

[38] D.06-06-035.

utility-owned resource. In A.06-04-012, PG&E has signed a Purchase and Sale Agreement (PSA) with E&L Westcoast Colusa, and an Engineering Procurement and Construction (EPC) contract with Wartsila Humboldt. Both projects will result in utility-owned power plants that are not eligible for this cost allocation. All three projects will count towards PG&E's needed MW.

11. SCE's Situation

SCE indicates that under the fast-track RFO, new resources would be brought to the Commission via an Application by February 2007 that might come online by 2010. We order SCE to file an Application no later than February 2007 seeking Commission approval of new resources, or the Commission will exercise its oversight authority to determine why SCE is delinquent in its compliance with today's Commission order.

SCE also wants to pursue new resources by way of a standard track RFO. SCE may conduct both RFOs to fill up to 1,500 MW of new generation as long as the utility files an application seeking Commission approval of some new resources to the Commission by February 2007. If SCE's application filed by February 2007 does not seek approval of 1,500 MW, SCE must justify in its application why it does not do so, including, inter alia, stating whether or not it received other bids in the fast track solicitation that are not included in the application (and the bid details), and why it is preferable for SCE to wait to seek approval of the remaining MW under its standard track solicitation.

The state, through the Governor and the legislature, and this Commission have signaled their joint commitment to reducing greenhouse gases (GHG). Although the Commission might not have a decision on its new GHG policy in place before SCE completes its fast-track RFO, we expect SCE and the other IOUs to follow the Commission's GHG policy, as enunciated in R.06-04-009, when they design RFOs and chooses the winning bidders.

12. SDG&E Concerns

In their comments to the draft decision, SDG&E and TURN request that the Commission extend this cost allocation mechanism to SDG&E's Otay Mesa facility. SDG&E elected Otay Mesa in its 2003 Grid Reliability RFP, and it has been assuming that the plant will receive RMR treatment, which is analogous but not identical to the cost allocation treatment adopted today.

We decline to extend this cost allocation mechanism to the Otay Mesa facility at this time, given that we limit application of this cost allocation mechanism in this decision to the need findings of the 2004 LTPP proceeding. SDG&E may propose additional need in Phase II of this proceeding and if approved, that need may be subject to the cost allocation treatment adopted here.

13. POU Concerns

Our definition of benefiting customers subject to the cost allocation mechanism does not apply to POU customers, unless the customer is subject to D.04-12-048, as modified by D.05-12-022. As noted in D.04-12-048, Ordering Paragraph 9, IOUs are required to forecast and plan for departing load as they file their biennial long-term procurement plans which establish each IOU's long-term resource needs.

14. Cogeneration Concerns

The CAC/EPUC requested that we allow cogeneration to bid in the all-source RFOs. We require that all new generation RFOs subject to this cost-allocation mechanism be open to any fuel and any technology. CAC/EPUC also request that cogeneration as departing load be exempt from this charge. We do not adopt this proposal at this time.

15. Concerns about RFOs

IEP and others requested that we examine RFO processes in this proceeding. We defer the review of IOUs RFO processes to Phase II of R.06-02-013.

16. Hearings

The OIR issued February 16, 2006, preliminarily determined that the proceeding was ratesetting, and that the issues may be able to be resolved through a combination of workshops and formal comments (as well as evidentiary hearings).[39] The schedule that was included in the OIR established dates for a prehearing conference, the filing of proposals on policies to support new generation, a workshop to discuss the proposals, post-workshop briefs, and a draft decision. No evidentiary hearings were forecast at that time. It was anticipated that the draft decision would reflect the record developed and informed by the proposals, the transcript from the workshop and the post-workshop comments and reply comments.

On March 29, 2006, the assigned Administrative Law Judge (ALJ) issued a ruling amending the comment schedule and setting an outline for the comments. Section VII of the outline asked parties to comment on whether there are "any issues of material fact that would benefit from evidentiary hearings, if so, please identify the issues and discuss hearing time needed for development of [the] record."[40]

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[39] OIR, February 16, 2006, p. 15.

[40] ALJ Ruling, March 29, 2006, p. 2.

Of the numerous parties submitting comments, only a few addressed Section VII with any substance. Many of the parties requesting hearings stated that evidentiary hearings are necessary on the issue of "need." We agree that if we were making a new finding of "need" in this decision, the record would have benefited from a robust examination of each IOUs' need numbers. However, we are not adopting new need numbers in this decision, but are relying on the numbers from the 2004 LTPP and/or the CEC's 2005 IEPR, both instances where need was heavily litigated and a record was developed on the subject. Furthermore, the need figures for SCE and PG&E are extremely conservative used in this decision.

We carefully reviewed the comments requesting hearings on subjects other than need and determined that we are not making any findings in this decision that revolve around any newly identified disputed material facts. Our findings in this decision are based on facts previously litigated and policy determinations. The Commission does not need an evidentiary record to exercise its discretion regarding policy matters.

Thus, additional material facts related to need and other issues that were identified by parties in their comments that would benefit from cross-examination are not being decided in this phase of the Rulemaking. The Scoping Memo that will issue for Phase II will indicate if evidentiary hearings will be necessary for the development of a record in that phase of the proceeding.

V. Motions

Numerous Motions to Intervene were filed in this proceeding and were addressed in an ALJ ruling granting all the motions. Following the ALJ ruling, California Small Business Roundtable and California Small Business Association

(CSBRT/CSBA) filed a Motion to Enter an Appearance and File Reply Comments. Motion is granted.

Any other motions filed in this proceeding to date that have not been the subject of a separate ruling or addressed in this decision are deemed denied.

VI. Comments on Draft Decision

The draft decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments and/or replies were timely filed by: Aglet, AReM, CAC/EPUC, CAISO, CARE, Calpine, CEC, CLECA/CMTA, CMUA/NCPA, Constellation, DRA, IEP, Indicated Parties, Joint Parties, Mirant, MID, NRG, PG&E, SCE, SDG&E, Sempra, TURN and WEM.

We make the following changes to the draft decision, and conforming changes to the findings of fact, conclusions of law, and ordering paragraphs:

- We refine the definition of "benefiting customers" to indicate that it does not include POU customers, unless the customer is subject to D.04-12-048, as modified by D.05-12-022. (Section IV.B.1 and IV.C.13.)

- We provide that this transitional cost allocation mechanism will be in place for the term of the contract or 10 years, whichever is less, but that the mechanics of the mechanism may change depending on the new market-based system which may evolve. (Section IV.B.3.) We require the IOUs to make the election at the time they seek contract approval from the Commission whether or not they intend the cost allocation mechanism adopted by this decision should apply to the contract. The Commission's decision on the IOUs'application will determine the applicable cost allocation mechanism. (Section IV.B.5 and Conclusion 6.)

- We now require, instead of encourage, the IOUs to utilize a third-party IE to oversee the RFO for new resources for long-term contracts. (Section IV.B.6.)

- In the draft decision, the IOU could determine that it no longer wanted to auction the rights to the energy. In response to comments, that option has been removed. (Section IV.B.17.)

- We refine the direction given to the IOUs regarding filing their Implementation Proposals regarding the energy auction and direct the Energy Division, in consultation with the Assigned Commissioner, to hold a workshop prior to the IOUs filing their Implementation Proposals, and subsequent workshops as needed. (Section IV.B.16.)

- We now require, instead of encourage, the IOUs to utilize a third-party IE to administer the energy auction. (Section IV.B.16.)

- We do not change our need determination but elaborate on the discussion. (Section IV.C.5.)

- The changes to the draft decision permit SCE to go forward with one fast-track and one standard-track solicitation, instead of just a fast-track solicitation. However, if SCE's application filed by February 2007 for approval of MW subject to its fast track solicitation does not seek approval of 1,500 MW, SCE must justify in its application why it does not do so, including, inter alia, stating whether or not it received other bids in the fast track solicitation that are not included in the application (and the bid details), and why it is preferable for SCE to wait to seek approval of the remaining MW under its standard track solicitation. (Section IV.C.5 and 11.)

- We clarify that we decline to extend this cost allocation mechanism to SDG&E's Otay Mesa facility at this time, given that we limit application of this cost allocation mechanism in this decision to the need findings in the LTPP proceeding. (Section IV.C.12.)

- We change the ordering paragraphs to require that PG&E shall not withdraw all or any part of its application for Commission approval of certain long-term contracts in A.06-04-012 without explicit Commission approval.

- We clarify that the utilities should be mindful of the Commission's greenhouse gas policy, as enunciated in R.06-04-009, as they design and conduct RFOs and as they choose the winning bidders. (Section IV.C.11.)

We also make non-substantive changes to the draft decision to more fully set forth the parties' positions, to clarify or improve the flow of the discussion, and to correct typographical errors.

VII. Assignment of Proceeding

Commissioner Michael R. Peevey is the Assigned Commissioner and CarolA. Brown is the Assigned ALJ in this proceeding.

Findings of Fact

1. The purpose of this decision is to adopt a policy, on a limited and interim basis, to support new generation and long-term contracts for California which can ensure investment in construction in a timely fashion so new generation can begin to come on-line in 2009.

2. This decision must work in concert to coordinate and incorporate Commission and legislative efforts from other proceedings, and in particular R.05-12-013 that is addressing competitive market mechanisms in Phase II of that proceeding.

3. The state's energy policy uniformly points to the need for the state to invest in new generation in both northern and southern California in order to assure continued reliable service at reasonable cost.

4. PG&E has a need for 2,200 MW and SCE has a need for 1,500 MW.

5. We intend to examine in Phase II of this proceeding whether there is any additional system need for new capacity in the service territories of SCE, PG&E and SDG&E.

6. We find that long-term contracts are necessary to solicit investment in new generation in California.

7. We previously implemented RAR for each LSE requiring it to be responsible for acquiring its own reserves to meet its own RA obligation.

8. In D.04-12-048, we approved the IOUs' LTPPs and associated rate-making treatment, and authorized the IOUs to enter into short-, medium-, and long-term contracts.

9. In D.04-12-048, we allowed the IOUs to recover any stranded costs from all customers for a period of either the life of the contract, or 10 years, whichever is less.

10. Despite our removal of barriers to long-term contracting by approving the IOUs' LTPP and cost recovery, establishing RAR year-ahead obligations and allowing for stranded cost recovery, neither PG&E nor SCE have entered into any long-term contracts or built new generation themselves.

11. PG&E and SCE have indicated that they are reluctant to take procurement steps that would leave the cost-recovery for new generation with their respective bundled customers alone, and they have requested cost-recovery for above-market costs from all customers.

12. Since our decision in D.04-12-048 in December 2004 there has not been sufficient investment in new generation in California from non-utility sources.

13. We find that we need an additional transitional policy to encourage investment in new generation resources now while we continue to pursue competition and customer choice by establishing a functioning market-based institutions.

14. We find given the urgent need for new capacity and the lengthy lead-times required both for new construction and to develop and implement new market institutions, it is necessary and prudent for us to take proactive steps now to support investment in new generation.

15. The only complete solution for this transitional policy presented to the Commission was the JPs' proposal which proposed making the IOUs the procurement entities for bundled and unbundled customers alike.

16. Many parties critiqued the JP, but only proffered the alternative solution of "staying the course" which translates into continuing with ongoing market reforms and hoping that new capacity will get built.

17. Other parties constructively analyzed the JP, including the Indicated Parties, and offered modifications that limited the procurement role of the IOUs.

18. We find that it is reasonable to adopt a cost allocation mechanism on a limited and transitional basis as more fully set forth in this decision, until we decide upon, develop and put in place new market-based institutions in Phase II of R.05-12-013. This cost-allocation mechanism shall remain in place for the term of the qualifying contract or 10 years, whichever is less. However, the mechanics of this cost-allocation mechanism may change depending on the new market-based system which is currently under development.

19. The cost allocation mechanism, that is set forth with particulars herein, will allow the advantages and costs of new generation to be shared by all benefiting customers in an IOU's service territory. We designate the IOUs to procure this new generation. The LSEs in the IOU's service territory will be allocated rights to the capacity that can be applied toward each LSE's RAR requirements. The LSEs' customers receiving the benefit of this additional capacity pay only for the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract.

20. As set forth with particularity herein, each IOU must conduct periodic auctions administered by an independent third party, for the energy rights for each of the resources acquired under this interim proposal.

21. This mechanism disaggregates the energy and capacity components of the newly acquired generation, so that the only non-bypassable charge levied is for

the net capacity costs, and the non-IOU LSEs retain the ability to manage their energy purchases.

22. We are not adopting this mechanism enthusiastically, but because it is necessary to assure grid reliability for the state as a whole that we remove any risk or barrier, real or perceived, that impedes investment in new generation.

23. Nothing we do in this decision prohibits IOUs or ESPs from contracting with other new resources that come online without the aid of long-term contracts with the IOUs.

24. We do not find that it is necessary or helpful for the cost-allocation mechanism we adopt herein to label the new resources as a "public good."

25. We will review in Phase II of this proceeding the need for new system resources in each IOU's territory, as well as to examine each IOU's bundled customer need.

26. We do not adopt an opt-out mechanism to this cost allocation methodology today, but defer further consideration to Phase II of R.05-12-013, so it can be considered in concert with capacity markets and multi-year RAR.

27. We find it is reasonable to use the need determination numbers from our last LTPP decision, D.04-12-048, and/or the numbers supported by the CEC's 2005 IEPR. Based on those findings, PG&E's need is 2,200 MW, SCE's need is 1,500 MW and SDG&E has no need for additional capacity from the need numbers we are using.

28. New need determination numbers will be established following the development of a record in Phase II of this proceeding.

29. PG&E has already brought the Commission over 2,200 MW of contracts in A.06-04-012, following the completion of its RFO for the need authorized in D.04-12-048. We will allow PG&E to apply the cost-allocation methodology to

contracts in A.06-04-012 with qualifying new generation that is not utility owned, provided the Commission approves such contracts in A.06-04-012.

30. PG&E cannot apply the cost-allocation methodology to CC8 or to its contracts with E&L Westcoast Colusa or with Wartsila Humboldt.

31. SCE has indicated a willingness to procure up to 1,500 MW of new long-term contracts and can complete a "fast track" RFO as early as February 2007. We find it reasonable for SCE to procure up to 1,500 MW in its "fast track" RFO depending on the robustiness of offers received. SCE also plans to conduct a "standard-track" RFO, to be completed at a later time. Between the "fast-track" and the "standard-track" RFOs, SCE may procure up to 1,500 MW of new generation subject to the cost allocation mechanism adopted here. If SCE's application filed by February 2007 does not seek approval of 1,500 MW, SCE must justify in its application why it does not do so, including, inter alia, stating whether or not it received other bids in the fast track solicitation that are not included in the application (and the bid details), and why it is preferable for SCE to wait to seek approval of the remaining MW under its standard track solicitation. We will address in Phase II whether SCE has need beyond 1,500 MW.

32. We find it reasonable for the IOUs, when they procure resources on behalf of all customers, to give high priority to resources that meet local RA obligations as established in R.05-12-013.

33. Pub. Util. Code § 380 clearly authorizes the Commission to adopt the cost allocation methodology set forth herein that supports new generating capacity and equitably allocates the costs.

34. We do not find it necessary or advisable at this time to limit this cost mechanism to non-affiliate transactions, as long as the contract evaluation and selection procedures are above reproach.

35. We do not adopt CAC/EPUC's request to exempt cogeneration from departing load charges.

36. The costs of utility procurement of eligible renewable resources to comply with the requirements of the RPS program are governed by the statutory requirements and Commission decisions implementing the RPS program.

37. We find it is consistent with the OIR issued on February 14, 2006, initiating this proceeding and the ALJ ruling on March 29, 2006, that the record that supports this decision is fully developed without evidentiary hearings. A separate determination will be made in Phase II of this rulemaking whether evidentiary hearings are necessary for the development of the record in that phase.

Conclusions of Law

1. Pub. Util. Code § 380, directs the Commission, in establishing RARs to facilitate the development of new generating capacity and to equitably allocate the cost of generating capacity. It is consistent with AB 380 for the Commission to adopt the cost-allocation methodology set forth herein.

2. Pub. Util. Code § 380, also allows the costs an IOU incurs to sustain system reliability and local area reliability to be fully recovered from all customers on whose behalf the costs are incurred. It is consistent with AB 380 for the Commission to adopt the cost-allocation methodology set forth herein so that the IOUs' bundled customers are not alone responsible for the cost of new generation to retain system reliability.

3. We have found that long-term contracts are necessary to solicit investment in new generation in California, and both the ESPs and the IOUs are unwilling to sign long-term contracts. The ESPs' customers are on short-term contracts and the ESPs cannot recruit new customers with the suspension of DA. The IOUs are concerned that without some cost allocation provision to assure that their bundled customers are not left paying for new generation in the face of departing load, that long-term contracts are too risky.

4. It is necessary for the Commission to take some proactive step now in order to assure continued reliable electricity service at a reasonable cost.

5. It is reasonable, and consistent with law, for the Commission to adopt this limited and transitional cost allocation mechanism to support the development of new generation by having the costs and benefits shared by all customers.

6. The IOUs shall make an election at the time they seek contract approval from this Commission whether or not they intend that the cost allocation mechanism adopted by this decision should apply to the contract. The Commission's decision on the IOUs' applications will determine the cost allocation mechanism that will apply. Contracts ineligible for this cost allocation mechanism, or contracts to which the IOUs elect not to apply this cost allocation mechanism at the time seeking Commission approval of the contract, are still subject to the rules of D.04-12-048.

7. We designate the IOUs to procure new generation, and as set forth more fully herein. The energy and capacity from the new resources should be unbundled. The LSEs in the IOU's service territory will be allocated rights to the capacity that can be applied toward each LSE's RAR requirements. The LSEs' customers receiving the benefit of this additional capacity pay only for the net

cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract.

8. The treatment of costs of utility procurement of eligible renewable resources to comply with the requirements of the RPS program should continue to be decided in the course of implementing the RPS program.

9. Pursuant to the plan adopted herein, each IOU is to conduct periodic auctions, for the energy rights to all resources acquired pursuant to this plan. These periodic auctions shall be administered by an independent third party.

10. It is reasonable to defer many of the implementation details of this cost-allocation mechanism to Phase II of this proceeding along with associated ratemaking issues.

11. It is consistent with our commitment to competition and customer choice to adopt this interim and transitional plan to assure investment in and construction of new generation capacity while we are deciding, developing and implementing a market-based institutional infrastructure.

O R D E R

IT IS ORDERED that:

1. The cost-allocation mechanism set forth with specificity herein is adopted. The investor-owned utilities (IOU) are to procure new generation, Pacific Gas and Electric Company (PG&E) 2,200 megawatts (MW) and Southern California Edison Company (SCE) 1,500 MW, and the energy and capacity from the new resources should be unbundled. The IOUs shall utilize a third-party independent evaluation (IE) to oversee the RFOs. The Load serving entities (LSE) in the IOUs' service territory will be allocated rights to the capacity that can be applied toward each LSE's resource adequacy requirements (RAR)

requirements. The LSEs' customers receiving the benefit of this additional capacity pay only for the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract.

2. Pursuant to the mechanism adopted herein and as refined in response to the IOUs' Implementation Proposals for an energy auction filed in Phase II, each IOU is to conduct periodic auctions for the energy rights to all resources acquired pursuant to this mechanism. The IOUs shall retain an independent third party to administer the auction. The Commission's Energy Division, in consultation with the Assigned Commissioner, shall hold a workshop prior to the IOUs filing their Implementation Proposals, and subsequent workshops as needed.

3. The IOUs are to follow the guidelines set forth herein in order to have the cost allocation mechanism applicable to their new generation resources.

4. This order does not apply to the treatment of costs of utility procurement of eligible renewable resources to comply with the requirements of the renewable portfolio standard (RPS) program.

5. It is reasonable to defer many of the implementation details of this cost-allocation mechanism (to Phase II of this proceeding) along with associated ratemaking issues.

6. PG&E shall not withdraw all or any part of its application for Commission approval of certain long-term contracts in Application 06-04-012 without explicit Commission approval.

7. SCE is to forthwith conduct a "fast-track" and a "standard-track" request for proposals (RFOs) for a total of 1,500 MW and bring long-term contracts for at least a portion of the 1,500 MW from the "fast-track" RFO to the Commission in an application for approval no later than February 2007, or be asked to justify its

non-compliance with this order. If SCE's application filed by February 2007 does not seek approval of 1,500 MW, SCE must justify in its application why it does not do so, including, inter alia, stating whether or not it received other bids in the fast track solicitation that are not included in the application (and the bid details), and why it is preferable for SCE to wait to seek approval of the remaining MW under its standard track solicitation. Only non-utility owned generation chosen by SCE in the RFOs will be eligible for this newly adopted cost allocation mechanism.

8. The IOUs are to be mindful of the Commission's greenhouse gas policy, as enunciated in R.06-04-009, as they design and conduct RFOs and choose winning bidders.

9. Nothing in this Order is to be read to prevent any Load Serving Entity, including the IOUs, from entering into any long-term contracts, from investing in new generation, or from building new generation that is not eligible for this cost-allocation mechanism established herein.

10. This cost-allocation mechanism will stay in place until it is replaced by subsequent Commission directives.

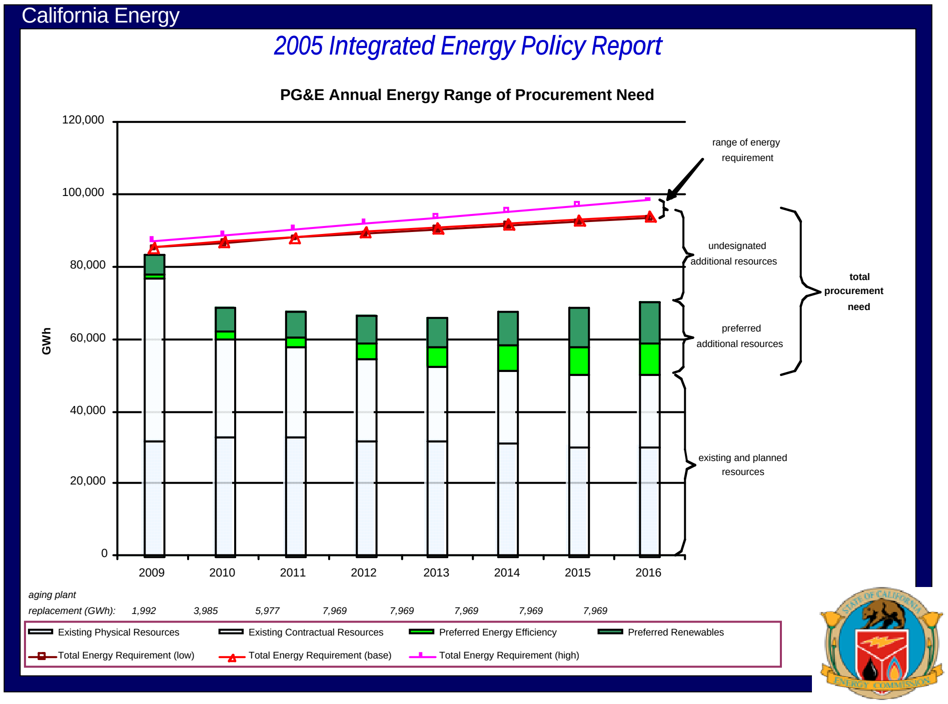
This order is effective today.

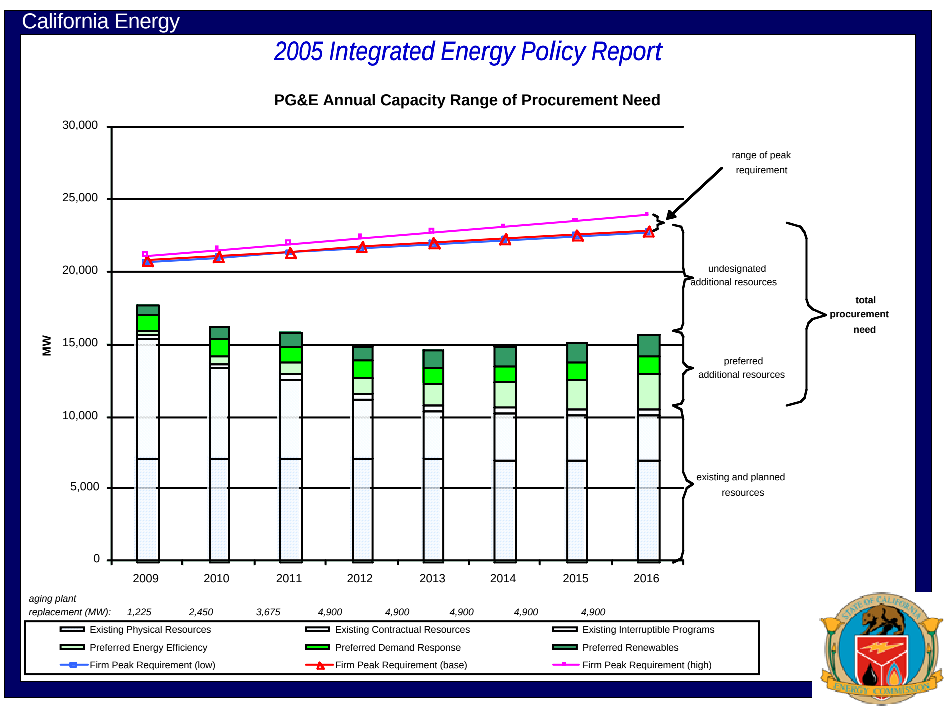
Dated July 20, 2006, at San Francisco, California.

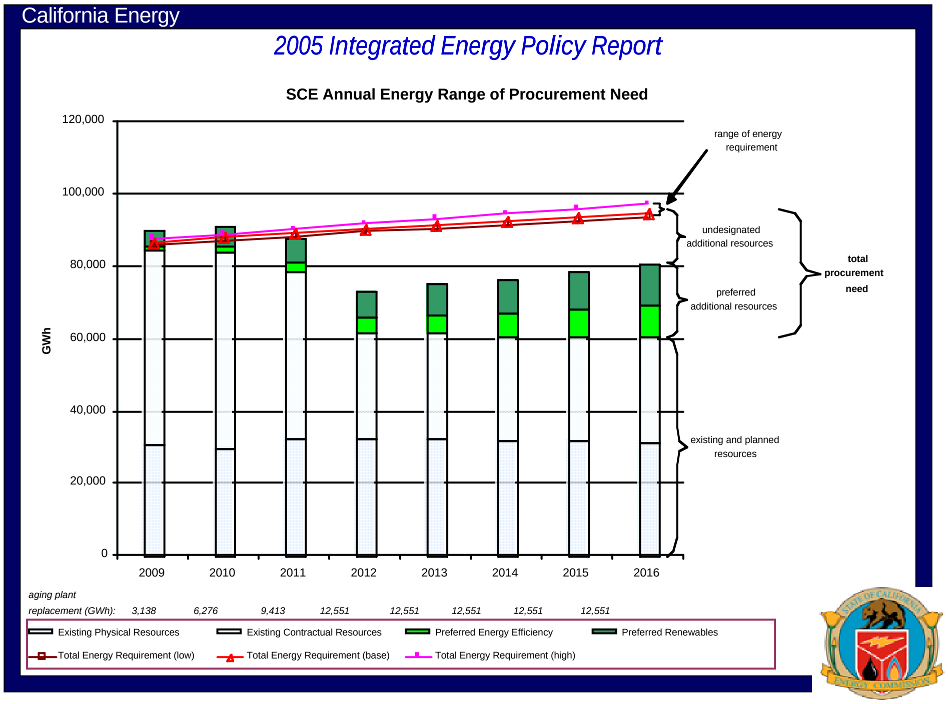
MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

APPENDIX A

Excerpt from Presentation of Kevin Kennedy, CEC's Integrated Energy Policy Report Coordinator, March 14, 2006.






California Energy
2005 Integrated Energy Policy Report
SCE Annual Energy Range of Procurement Need
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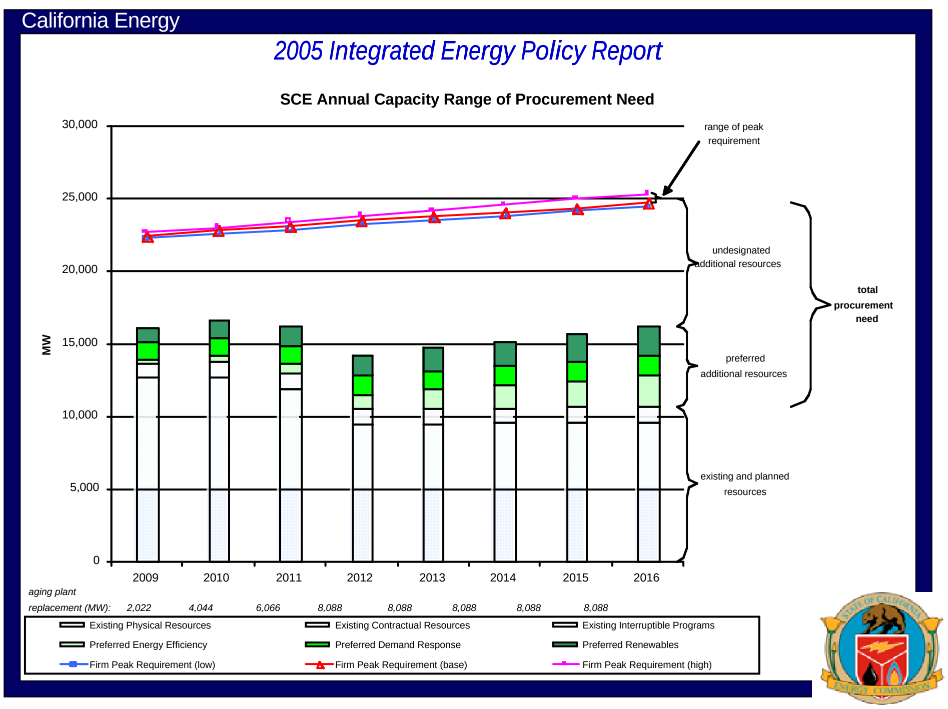
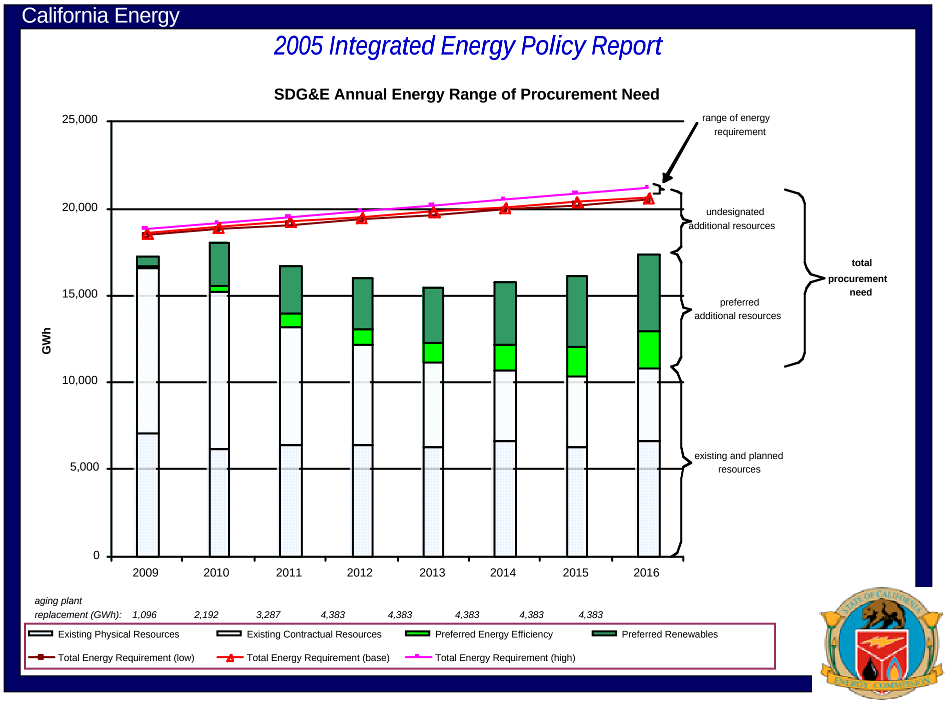
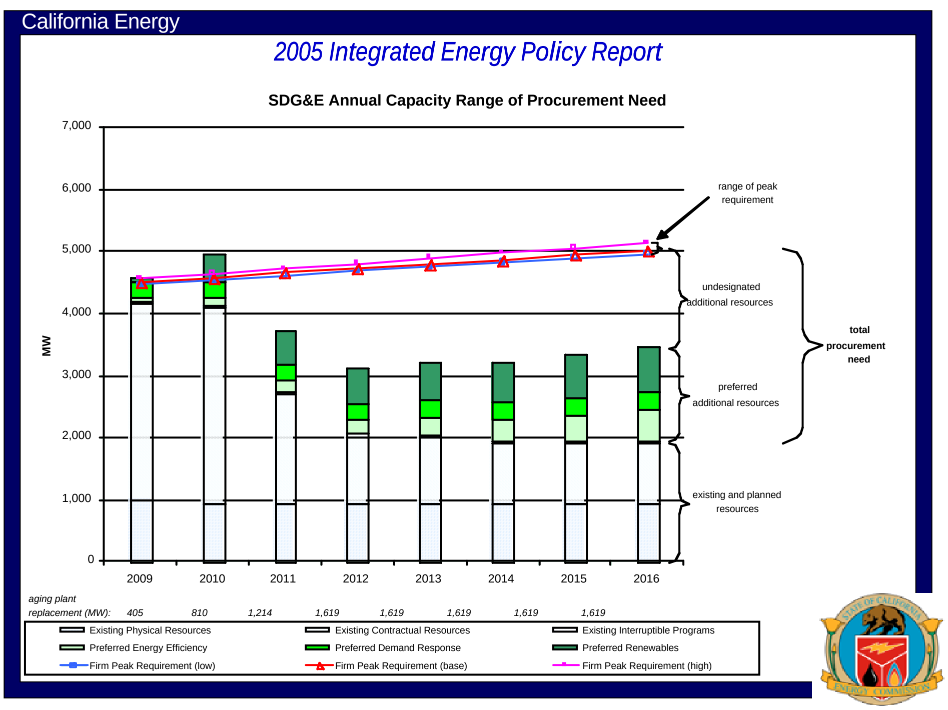
100,000
80,000
60,000
40,000
20,000
0
GWh
2009
2010
2011
2012
2013
2014
2015
2016
range of energy requirement
undesignated additional resources
preferred additional resources
existing and planned resources
total procurement need
aging plant replacement (GWh): 3,138 6,276 9,413 12,551 12,551 12,551 12,551 12,551
Existing Physical Resources
Existing Contractual Resources
Preferred Energy Efficiency
Preferred Renewables
Total Energy Requirement (low)
Total Energy Requirement (base)
Total Energy Requirement (high)


California Energy
2005 Integrated Energy Policy Report
SCE Annual Capacity Range of Procurement Need
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
2009
2010
2011
2012
2013
2014
2015
2016
range of peak requirement
undesignated additional resources
preferred additional resources
existing and planned resources
total procurement need
aging plant replacement (MW): 2,022 4,044 6,066 8,088 8,088 8,088 8,088 8,088
Existing Physical Resources
Existing Contractual Resources
Existing Interruptible Programs
Preferred Energy Efficiency
Preferred Demand Response
Preferred Renewables
Firm Peak Requirement (low)
Firm Peak Requirement (base)
Firm Peak Requirement (high)





(END OF APPENDIX A)

APPENDIX B

Excerpt from Presentation by Dave Ashuckian, California Energy Commission, Electricity Demand Office, March 14, 2006.

2006 – 2010 Five Year Electricity Outlook CA ISO Northern Region (NP26)

	Resource Adequacy Planning Conventions	2006	2007	2008	2009	2010
1	Existing Generation	24470	24413	24413	24413	24413
2	Retirements (Known)	-219				
3	High Probability CA Additions	162				
4	Net Interchange [1]	550	650	600	550	500
5	Total Net Generation (MW)	24,963	25,063	25,013	24,963	24,913
6	1-in-2 Summer Temperature Demand (Average) [2]	20,395	20,747	21,074	21,423	21,799
7	Demand Response (DR)	245	245	245	245	245
8	Interruptible/Curtailable Programs	260	260	260	260	260
9	Planning Reserve [3]	24.9%	23.2%	21.1%	18.9%	16.6%
	Expected Operating Conditions					
	Total Net Generation (MW) (Line 5)	24,963	25,063	25,013	24,963	24,913
10	Outages (Average forced + planned)	-1,100	-1,100	-1,100	-1,100	-1,100
11	Zonal Transmission Limitation [4]	0	0	0	0	0
12	Expected Operating Generation with Outages/Limitations [5]	23,863	23,963	23,913	23,863	23,813
13	Expected Operating Reserve Margin (1-in-2) [6]	17.5%	15.9%	13.8%	11.7%	9.5%
	Adverse Conditions					
14	High Zonal Transmission Limitation	0	0	0	0	0
15	High Forced Outages	-500	-500	-500	-500	-500
16	Adverse Temperature Impact (1-in-10)	-668	-680	-691	-703	-715
17	Adverse Scenario Reserve Margin [7]	11.2%	9.8%	7.8%	5.7%	3.6%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles [8]	13.7%	12.2%	10.1%	8.1%	5.9%
19	Resources needed to meet adverse 7.0% reserve (W/DR & Interruptibles)	0	0	0	0	233
20	Resources needed to meet adverse 5.0% reserve (W/DR & Interruptibles)	0	0	0	0	0
21	Resources needed to meet adverse 1.5% reserve (W/DR & Interruptibles)	0	0	0	0	0
22	Existing Generation Without Capacity Contracts [9]	-682	-682	-2,663	-2,663	-2,663

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2006 – 2010 Five Year Electricity Outlook CA ISO Southern Region (SP26)

Resource Adequacy Planning Conventions	2006	2007	2008	2009	2010
1 Existing Generation[1]	21321	21708	21708	21708	21708
2 Retirements (Known)	-1,320				
3 High Probability CA Additions	1,707				
4 Net Interchange [2]	10,100	10,100	10,100	10,100	10,100
5 Total Net Generation (MW)	31,808	31,808	31,808	31,808	31,808
6 1-in-2 Summer Temperature Demand (Average)[3]	27,027	27,457	27,911	28,383	28,818
7 Demand Response (DR)	395	395	395	395	395
8 Interruptible/Curtailable Programs	950	950	950	950	950
9 Planning Reserve[4]	22.7%	20.7%	18.8%	16.8%	15.0%
Expected Operating Conditions					
Total Net Generation (MW) (Line 5)	31,808	31,808	31,808	31,808	31,808
10 Outages (Average forced + planned)	-1,155	-1,155	-1,155	-1,155	-1,155
11 Zonal Transmission Limitation[5]	-150	-150	-150	-150	-150
12 Expected Operating Generation with Outages/Limitations[6]	30,503	30,503	30,503	30,503	30,503
13 Expected Operating Reserve Margin (1-in-2)[7]	16.6%	14.3%	11.9%	9.5%	7.4%
Adverse Conditions					
14 High Zonal Transmission Limitation	-250	-250	-250	-250	-250
15 High Forced Outages	-560	-560	-560	-560	-560
16 Adverse Temperature Impact (1-in-10)	-2,110	-2,145	-2,182	-2,220	-2,255
17 Adverse Scenario Reserve Margin[7]	2.4%	0.4%	-1.7%	-3.7%	-5.5%
18 Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	8.3%	6.1%	3.9%	1.8%	-0.1%
19 Resources needed to meet adverse 7.0% reserve (W/DR & Interruptibles)	0	209	735	1,280	1,783
20 Resources needed to meet adverse 5.0% reserve (W/DR & Interruptibles)	0	0	255	790	1,284
21 Resources needed to meet adverse 1.5% reserve (W/DR & Interruptibles)	0	0	0	0	410
22 Existing Generation Without Capacity Contracts (Information Only)[9]	-2,370	-3,010	-5,280	-5,280	-5,280

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Chart Foot Notes

1 Dependable capacity by station includes 1,080 MW of stations located South of Miguel.

2 2006 estimate Imports with own reserves: Statewide 12,118 MW; CA ISO 9,650 MW; NP26 550 MW; and SP26 6,100 MW

3 September forecast showing adopted CEC 2005 IEPR high case forecast.

4 Planning Reserve calculation ((Total Generation + Demand Response + Interruptibles)/Normal Demand)-1.

5 Based on CA ISO data.

6 Does not include Demand Response/Interruptible Programs due to Reserve Margins in excess of 5% (Stage 2).

7 Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1.

8 Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.

9 Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements

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(END OF APPENDIX B)

APPENDIX C

Post-Workshop Comments

I. Comments Encouraging New Generation

A. Joint Parties

The Joint Parties argue that the Commission cannot simply "stay the course" of current regulatory policies and hope that new generation will develop. They explain that current policies have not induced sufficient investment and argue that the Commission cannot ensure the construction of new generation while relying on current policies that would unlawfully burden bundled-service customers with the cost of new generation.

Most of the opposition to the JP focuses on the cost allocation mechanism. The Joint Parties try to refute this opposition by reiterating that the JP is an interim concept only intended to be in place until there is a long-term solution, such as a functioning, centralized capacity market, and the JP is not a new paradigm for procurement that moves in the direction of more utility integration.

The Joint Parties stress that the cost allocation plan set forth in the JP fairly socializes the costs and benefits of new generation to all customers. The Joint Parties stress how unfair it would be to have their bundled-customers solely responsible for the long-term commitments necessary to encourage new generation that will benefit all customers and all LSEs within the IOU's service territory. In addition, the Joint Parties address other questions raised in the comments with the following clarifications: Debt equivalence will not be included in the socialized costs; the JP will not adversely affect the State's adopted loading order from EAP II since conventional resources are only added after preferred resources have been maximized; and the Joint Parties understand the need for transparency and will work with other parties on developing appropriate safeguards, but do not want to delay implementation of the process by attempting to resolve those issues now.

The Joint Parties had the opportunity to have their JP fully vetted at the workshop so they were able to support their proposal by addressing in their comments and reply the issues raised at the workshop. In particular, in response to concerns that the JP[1] was moving in the direction of vertical integration of the IOUs, the Joint Parties explain how third-party investment companies can participate in future solicitations for new generation resources. The Joint Parties suggest that once the cost allocation principles in the JP are adopted, certain aspects of the Indicated Parties' plan can be folded into the JP structure, and details can be worked out in future solicitations. While the Joint Parties believe the Indicated Parties' plan is based on some faulty assumptions about the JP, the Joint Parties do not want the discussion of the Indicated Parties plan to delay implementation of the JP as they believe it is necessary to implement it now for system reliability.

B. Joint Parties' Separate Comments

In addition to joining in the JP, SCE, PG&E and TURN each filed an individual set of comments. SCE believes the JP will protect its bundled customers and states that SCE "will not enter into such contracts if its

[1] In post-workshop comments, the JP included SCE, PG&E, NRG, TURN, CURE, and CURE. Another party on the original proposal, AES, filed separate supportive comments.

bundled-service customers alone are required to pay the full costs of new generation resources that will support system reliability for all customers."[2] SCE also declares that it believes in the efficacy of a capacity market and that the JP should not hinder that market's development. Once a capacity market is functioning, the resources developed by the JP should be submitted to the capacity market.

SCE believes there is no merit to SDG&E's concerns that SCE is attempting to foist costs for new generation on to SDG&E customers by citing the needs as South of Path 15 (SP-15) area needs (instead of just SCE territory).

PG&E joins in SCE's interest of protecting bundled customers and states: "It would be inequitable to require only bundled customers to pay the higher cost associated with such new resources and allow direct access customers to reap the benefits of lower cost existing resources."[3] From PG&E's perspective, Commission approval of the new cost allocation methodology is a condition precedent to PG&E finalizing the generation contracts from its recent long-term RFO and for the Contra Costa 8 (CC8) facility so that PG&E can "ensure that its bundled customers are not saddled with a disproportionate share of developing new resources for the region."[4] PG&E restates that the JP should apply to utility-owned assets as well as PPAs.

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[2] SCE Comments, p. 3.

[3] PG&E Comments, pp. 5-6.

[4] PG&E Comments, p. 6.

TURN addressed the issue of how much new capacity might be necessary to assure reliable service, while balancing system cost and reliability. TURN argues that the Commission should find that there is a need to be met only if it finds that the resources available to serve its jurisdictional customers will fall short of the 15% to 17% Planning Reserve Margin (PRM) adopted in D.04-01-050. TURN is concerned that if a higher standard of need is adopted by the Commission, there will be additional costs on customers for a limited increase in reliability. In fact, from TURN's analysis of the data, PG&E does not have a need for additional resources through 2011 beyond what it has already committed to (including commitments from its recent RFO) but SCE does have a need before 2012.

If SDG&E is able to go forward with the Otay Mesa PPA with Calpine Corporation, as authorized in D.04-06-011 and on rehearing D.06-02-031, TURN does not anticipate SDG&E having any additional short-term need. Although SDG&E did not join in the JP, TURN suggests that the Otay Mesa Generating Plant (if it is built and comes on line), should also be subject to the JP. TURN also notes that SDG&E's example of having built some new generation shows the need for the JP because SDG&E was able to get Reliability Must Run (RMR) treatment for some portion of the new plants. RMR treatment spreads some of the fixed costs of the plant to all benefiting customers in the local reliability area. TURN notes that RMR treatment is simply not an adequate substitute for the JP since not all areas that need resources can qualify for RMR.

In its reply comments, TURN responds to the JP's opponents by reminding them that it is not in any LSE's or its customers' interest to take on the cost of new generation. Without the incentive that the JP offers for cost allocation, TURN is convinced that no new generation will be built. As TURN puts it, absent a multi-year RAR requirement, "there is an inherent hole in the Commission's RA[R] policy."[5] TURN argues that telling IOUS to "just do it" and attempting to force IOUs to sign long-term contracts is unfair to bundled customers. The IOUs, TURN argues, are under no obligation to procure any particular percentage of their bundled customer needs from new capacity. Therefore, the Commission needs to figure out how to ensure new generation needed for system reliability gets built when it is not in the interest of any LSE or its customers to take on such an obligation. TURN states, "It is a major leap of faith for any party to assume that the current schedules in this case, and in R.05-12-013 will necessarily result in the timely development of new generation."[6]

C. AES

AES was an original member of the Joint Parties, and although no longer a sponsor of the JP, AES continues to support it. From AES' perspective, RAR and LTPP alone will not motivate investors to develop and construct the next wave of incremental generation in a timely fashion. AES, like other independent power producers (IPPs), will not make the capital investment without a stable revenue mechanism.

AES, however, does have a few concerns with the process set forth in the JP. Specifically, AES, questions whether the IOUs will design an

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[5] TURN, Reply Comments, p. 4.

[6] TURN, Reply Comments, p. 7.

RFO that does not favor the utility or its affiliate, especially vis-à-vis issues such as debt equivalence applicability to PPAs. AES offers suggestions to make the RFOs more open and competitive, a topic that will be further developed in Phase II of this rulemaking.

D. DRA

DRA is supportive of the Commission taking some steps to encourage new generation, but prefers certain aspects of the Distco model. However, DRA is very insistent that the Commission must do something now on the cost allocation issue since "relying on RAR as the sole regulatory measure for meeting the approaching resource gap for the 2008-2011 time frame might be ultimately be more costly than if the Commission adopted a limited cost allocation methodology now."[7] DRA also supports of an interim cost allocation measure as some insurance against a hastly, and perhaps poorly designed, capacity market. However, DRA cautions the Commission to take the EAP II into consideration and only adopt the low end of the need range for this interim proposal.

E. CARE

CARE generally supports the JP, but would appreciate the opportunity to fairly consider other proposals.

F. CSBRT and CSBA

CSBRT and CSBA acknowledge that new generation is needed now in California and support the JP as an interim approach to achieve that goal.

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[7] DRA Comments, p. 7.

II. Parties Primarily Preferring to Stay the Course, or Offering Modifications to the JP

A. CAC/EPUC

CAC/EPUC acknowledge that there is a need for new generation in California now, but they do not support the JP because the cost allocation proposal would assess costs to departing load, which they fear could apply to new cogeneration. In summary, CAC/EPUC do not endorse the JP because they are not convinced it is an interim proposal, but one that could morph into a permanent one, and because it fosters traditional, fossil fuel generation, not cogeneration. The major concern of CAC/EPUC is preserving the place for cogeneration qualifying facilities (QF) in the loading order prescribed by EAP II, and not having the IOUs fill all of their need with traditional generation. However, CAC/EPUC ask that if the Commission adopts the JP, or a similar plan, that it apply the plan to new generation from any source, including new cogeneration facilities.

B. Mirant

Mirant believes that the wholesale power market in California does not produce adequate revenues to encourage and support investment in new generation. From Mirant's vantage point, the Commission's focus should be on fixing the wholesale market structure, but recognizes that an interim plan "may be needed while these market reforms are being implemented and given time to work."[8] Therefore, Mirant reluctantly

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[8] Mirant Comments, p. 5.

offers modifications to the JP to make it more in line with the Distco plan. Mirant believes this is necessary to signal that market stability is forthcoming and that California is a desirable environment for investment, without the need for "interim" solutions. Mirant does not support the JP as presented, because it perpetuates the existing dysfunction in the market. However, if the Commission adopts an interim measure, Mirant offers the following changes to the JP to create clear boundaries: limit the plan to a specific amount of new capacity for a specific time frame, consistent with moving towards the wholesale market; limit the cost allocation to the RAR portion; and have it apply to PPAs (not utility-owned generation).

In the meantime, Mirant advocates that the Commission continue to implement RAR, as well as reforms to the market redesign technology update (MRTU), and develop and implement a well-designed capacity market. "If a market structure is developed with the right components and allowed time to gain a foothold, it reasonably can be expected to encourage new investment on its own without the need for regulatory constructs being proposed."[9]

C. Constellation

Constellation's favored position is that the Commission "stay the course" and allow the RAR to work. However, Constellation understands that the "reality of the California energy market is that it is not just the ESPs who are not investing in energy infrastructure in California--*no one is investing,* not ESPs, not generation developers, not the investment banks,

[9] Mirant Comments, p. 10.

not the IOUs, not customers--because market signals in California do not show a need for new capacity."[10] From Constellation's perspective, it would be imprudent today to buy new generation unless investors can get a guarantee to charge "more that the current prevailing market price." Therefore, Constellation fears that investment backed by regulatory guarantees will remain the primary source of infrastructure investment in California, until and unless there is a competitive market.

Constellation urges the Commission to either reject the JP, or if it adopts the JP, to modify it so the Commission is taking steps consistent with where it ultimately wants to go. "To the extent the Commission determines that resources must be committed now to ensure reliable grid operations, there is a need for interim investment policies. The critical task, …, is to ensure that the "fix" does not become an impediment to the success of the emerging wholesale market structure."[11] Constellation would prefer that the Commission explore the Distco plan as an alternative to the JP, but in any event, advocates that the Commission should provide clear direction that any interim proposal will be replaced with a competitive market investment incentives supported by RAR and CAISO's MRTU.

D. Aglet

Aglet opposes the JP and the Distco plan from a concern that the IOU customers would not receive 100 % of the benefits from the new

[10] *Id*., p. 13.

[11] Constellation Comments, p. 15.

generation, but might get 100% of the costs. Aglet is concerned that there could be legal and administrative impediments to spreading the costs of new generation, and therefore the bundled IOU customers would be burdened with the cost. Aglet wants the IOUs to procure just for their bundled customers. As Aglet comments, "the Commission must determine whether the need for new generation is severe enough to eliminate a workable system and replace it with an experimental cost allocation method."[12] Aglet points to PG&E's recent RFO for the proposition that mechanisms already exist to ensure that there are long-term contracts available. From its perspective, Aglet recommends that the Commission order each IOU to fill its required need, and new generation should be added only if it is cost effective.

E. AReM

AReM's comments focus mainly on opposing the JP. Instead of adopting a new program, AReM urges the Commission to direct the IOUs to procure for the needs of their bundled customers, just like SDG&E did two years ago when it held an RFO for grid reliability. AReM thinks the Commission should consider sanctions against PG&E and SCE for willfully avoiding filling their obligations to procure for their bundled customers.

AReM is concerned that the JP just adds to the regulatory uncertainty that investors find as an impediment to investment in California. AReM also questions whether the cost allocation mechanism in

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12 Aglet Comments, p. 4.

the JP is legally sustainable. If not, there would be further market distortions. Therefore, AReM advocates the policy of "staying the course" and allowing current policies to work. If the Commission is inclined to adopt a new policy, AReM recommends the following: clearly define the need for new capacity; decouple energy and capacity and have the IOUs procure energy only for their bundled customers, do not allow the JP for utility-owned generation, and limit the interim plan to five years.

F. POU Parties

Merced Irrigation District, Modesto Irrigation District, South San Joaquin Irrigation District, Northern California Power Agency and the California Municipal Utilities Association, herein referred to as the Joint POU Parties, oppose the JP. However, they are not against the concept that the Commission should adopt some other new measure to encourage new generation. A major concern of the Joint POUs is that costs may be shifted for generation that is consumed by IOU bundled customers to customers of Joint POU parties from the IOUs. In addition, the Joint POUs urge the Commission not to adopt a hastily drafted plan that was subject to workshops, but ask that any proposal be deferred to a proceeding where it can be more fully explored.

If, however, the Commission is considering the JP, the POU parties request the following modifications: clarify that POU parties outside of the CAISO control area will not be subject to the JP; require the IOUs to forecast customer movements from IOUs to POUs so that the IOU does not procure for those departing customers; clarify that "IOU nondistribution transmission customers" are not included; eliminate all suggestions that POU customers should have responsibility for future

LTPP decisions of IOUs; and clarify that Assembly Bill (AB) 380 does not include POUs within the definition of an LSE.

G. Sempra Global

Sempra states that "[t]he Commission cannot create a stable regulatory environment, promote new investment in infrastructure, or even expect that its policies will be taken seriously if it continually suspends, overrides and tinkers with its programs before it has gone through even a single cycle of procurement."[13] From Sempra's vantage point, if guidance is needed from the Commission, it is on how rules and policies will be enforced--not on how the rules and policies should be changed. In particular, Sempra blames PG&E and SCE for creating the alleged problem by refusing to procure the resources ordered in the last LTPP decision, D.04-12-048. In fact, only SDG&E carried through and met the needs of its service territory and sought to have the incremental benefits shared through RMR contract designation.

While urging the Commission to "stay the course," which to Sempra means implementing RAR rules and a capacity market, Sempra also alternatively provided input on modifications to the JP. Sempra's primary goal is to limit the impacts of any new proposal on the development of wholesale and retail markets. Therefore, Sempra recommends the following modifications to the JP: limit any interim mechanism to a one-time RFO; limit it to "urgent need"; do not retroactively apply the interim mechanism to PG&E; limit the cost allocation methodology to three to four years, subject to a revisit; allow LSEs to "opt out" if they can demonstrate they have sufficient resources;

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[13] Sempra Comments, p. 2.

allow LSEs that procure new long-term resources to transfer fixed cost to the local IOU for recovery through the distribution-rate surcharges; do not permit cost allocation to apply to utility-owned generation or affiliate transactions; permit affiliate transactions and utility-owned generation so long as costs are recovered from bundled customers only; require the utilities to make public the winning contracts subject to cost allocation; make IOUs subject to reasonableness reviews for their procurement and dispatch of these resources; and design an interim plan which terminates once a centralized capacity market is functioning.

Sempra prefers the modifications it suggests to the Distco model as Sempra fears that despite its intentions, the Distco plan could be anticompetitive in the long term. Instead, the units subject to the cost allocation mechanism should be required to offer an energy option based on a heat-rate strike price to all customers paying the distribution charge. In its reply, Sempra counters arguments claiming that only the IOUs are willing or capable of making long-term resource commitments. Sempra submits that its nonutility LSE would be willing to undertake additional procurements if the Commission further requires that LSEs should procure a certain percentage of "new" resources as part of their RA obligation.

H. CLECA/CMTA

CLECA/CMTA urge the Commission to "stay the course." They do not find the JP interim, necessary or equitable and argue that adoption of the JP will "fundamentally alter the market structure in California, further eroding investor confidence in California's regulatory stability."[14] In addition, CLECA/CMTA see the IOUs, in particular PG&E and SCE, as playing a game of "chicken," with their refusal to follow through with their approved LTPPs from D.04-12-048. CLECA/CMTA find no regulatory impediment to the IOUs signing long-term contracts, and claim that both IOUs are failing in their responsibilities as public utilities.

If however, the Commission does consider the JP, CLECA/CMTA urge that it be modified as follows. The JP should not (1) be applied retroactively to PG&E's recent long-term RFO and to Contra Costa 8; (2) be applied to utility owned generation; and (3) last longer than 10 years. Also, CLECA/CMTA argue that an IOU is not the only entity that can procure new generation. CLECA/CMTA are also concerned that if the JP is adopted, non-bundled customers will pay for above market costs of energy procured to serve bundled customers without having access to the energy. Finally, CLECA/CMTA posit that the JP does not address whether IOUs will seek to procure new generation in locations that solve local RA problems.

CLECA/CMTA also raise the issue of whether the JP would only be a transitional mechanism. CLECA/CMTA are concerned that it will become permanent, fundamentally altering the market structure of California.

I. Green Power Institute

[14] CLECA/CMTA Comments, p. 3.

On fundamental principles of fairness, Green Power opposes the JP as being "considerably more generous" than any cost mechanism available through the RPS program. Previously, TURN suggested using IOUs as a means of facilitating the procurement of renewable power by the smaller LSEs, and Green Power supports that concept if it could be implemented through the JP.

J. IEP

IEP opposes the JP primarily on the ground that "staying the course" will provide the regulatory certainty needed for new generation. IEP does not want the Commission giving the IOUs more control over procurement, because it fears that the JP is moving towards utility integration. However, if the Commission adopts the JP, IEP suggests that the Commission consider that the procurement entity be someone other than an IOU.

From IEP's perspective, the problem lies with the IOUs and the way the IOUs design the RFOs. If the solicitations were all-source, they could result in "the optimum mix of new generation, existing generation and repowering projects if [the solicitations were] given a chance to function as the Commission intended."[15] According to IEP, the resource shortage problem is not the result of the current cost-allocation scheme, but a combination of the following: regulatory incentives that favor utility owned generation over PPAs; utilities being primary purchasers and

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[15] IEP Comments, p. 2.

sellers of power; IOUs finding unique-fleeting-opportunities (UFOs) to present to the Commission, rather than holding all-source competitive solicitations; the procurement process is lengthy and draped in excessive confidentiality; IOUs impose high credit requirements in their RFOs; and the debt equivalence adds to the cost of the PPAs.

K. WPTF

WPTF opposes the JP for the following reasons: the JP is not needed for reliability or to ensure RA compliance; it obstructs the long-term solution of all-source solicitations, capacity market and direct access; it creates a new stranded cost; it harms competitive markets by tasking the IOUs with the responsibility of procuring power for their competitors; bundled customers are already protected from stranded costs through the 10-year NBC authorized by D.04-12-048; and it will cause billing and price transparency problems. Instead, WPTF advocates that the Commission "stay the course" and not impose a temporary solution to address a scenario brought on by PG&E and SCE's refusal to procure sufficient resources. In the alternative, WPTF urges the Commission to order the IOUs to procure resources through all-source solicitations.

However, if the Commission chooses to adopt an interim plan, WPTF alternatively offers the following suggestions: require all-source solicitations; limit the number of MWs procured based on CEC and CAISO needs assessments; provide for an opt-out for non-utility LSEs upon a showing of RA; limit any IOU backstop procurement to RAR capacity only; make bids open and transparent; apply the policy only apply to PPAs, not utility owned generation and not to PGE's commitments from its recent RFO; do not extend the policy beyond 10 years; require that the entity procuring new capacity be anyone other than an IOU; and unbundle the energy and capacity components of the contract, as suggested in the Distco plan so as to maximize the energy rent.

L. SDG&E

SDG&E opposes the JP since the utility fears it will result in cross subsidies and potential stranded costs. SDG&E is particulary concerned that SCE might procure new resources, without first determining SDG&E's need for that capacity. SDG&E does not want SCE allocating 20% of the SP-15 shortfall to SDG&E regardless of SDG&E's resource position. Instead, SDG&E urges the Commission to focus on long-term solutions and move towards a capacity market, and not adopt the JP -- because it is really a long-term mechanism in disguise. If however, the Commission is considering the JP, SDG&E advocates having an opt-out provision for LSEs that are fully resourced.

M. SVLG

SVLG opposes the JP mainly on the ground that it represents a policy change toward returning IOUs to favored market position. SVLG does not believe that financing new power plants in California is difficult because of shifting customer bases, but rather because of the uncertainty of market rules. Instead, SVLG strongly supports "staying the course." However, if the Commission is considering an interim proposal, SVLG prefers aspects of the Distco plan to the JP, but only while the Commission is continuing to develop the LTPP and RAR framework. If SVLG urges that any interim proposal should only apply to peaking plants to secure reliability, that IOUs should procure base load or intermediate plants for their own growing energy needs, and that in no event, should the JP apply to utility ownership.

III. Parties Supporting Distco Plan or Who Take No Position on the JP

A. CEC

The CEC is the drafter of the 2005 IEPR and as such, the CEC's role in this phase of the proceeding is to coordinate the transmittal of the information developed and analyzed in the preparation of the IEPR for use in the Commission's 2006 LTPP proceeding. Consistent with that role, the CEC did not take a position on the JP. The CEC does not see that there are any barriers to the IOUs obtaining long-term contracts, except for a need for "coming and going" rules to deal with the uncertainty of future departing and returning load. According to the CEC, if the Commission adopts "coming and going" rules by the end of 2006 as the CEC recommended in its 2005 IEPR, that should provide an alternative to the cost-sharing mechanisms in the JP and the other proposals.

The CEC established the range of need for the three IOUs in the IEPR and believes that its "contractually based range of need" numbers demonstrate that IOUs have sufficient need for new resources to (1) serve the demand for their bundled customers and (2) reduce dependence on old and inefficient power plants. The CEC is concerned that if the Commission wants to determine a separate "physical need" number for this proceeding, this process is likely to be contentious and require a significant expenditure of time and resources to resolve and will delay the issuance of this decision.

B. Indicated Parties

As discussed earlier in this decision, the Indicated Parties made modifications to the Investco proposal discussed at the workshop, produced their own proposal dubbed Distco, and urge the Commission to adopt the Distco model in lieu of the JP. In their reply comments, the Indicated Parties favor further consideration of proposals that will (1) unbundle the capacity and energy components of any new generation procured; (2) limit the need for cost allocation to the RA component; and (3) allow energy rights of new resources to be acquired and paid for by individual market participants through a forward auction. In addition, the Indicated Parties believe that their proposal can be implemented quickly.

C. FPL Energy, LLC

FPL Energy, LLC only filed reply comments that indicated support for the Indicated Parties' proposal.

IV. Other Comments

A. CAISO

CAISO does not comment on the JP or the Distco plan, but instead limits its response to the "needs" issue. In terms of need, CAISO reiterated the "Three R's" of RAR: (1) the right mix of resources; (2) resources that are in the right location; and (3) the right amount of resources. In summary, out of its concern for sufficient resources, CAISO recommends that the Commission periodically conduct cost/reliability analysis projected over the expected term of the LTPPs to reaffirm or adjust the level of resource insurance that is in the best interest of California consumers as the state's resource supply and demand projections evolve over time.

B. RCM Biothane

RCM's concern is that the JP must be adjusted to exempt net-metering customers from any non-bypassable charge.

C. Good Company Associates on Behalf of TAS

Good Company presents a proposal of its own: the Commission should utilize technology it has available, Turbine Inlet Cooling, to provide additional capacity in a more expeditious manner. Good Company's proposal is based on the premise that in the long run, market forces are generally superior to regulation. However, to resolve short-run reliability problems, TAS has technology available that may help provide a bridge until long-run solutions work.

D. Davis Hydro

Davis Hydro urges the Commission to utilize available small distributed renewable generation to increase RA.

E. CCDG

CCDG Coalition recommends that the integrated planning process should include the establishment of procurement targets for distributed generation (DG). In light of the IEPR and EAP II, the Commission should consider requiring the LSEs to have annual procurement targets for combined heat and power facilities.

F. WEM

WEM advocates that the Commission follow the EAP II priority and focus more on energy efficiency (EE) rather than building more fossil-fueled generation. WEM fears that the JP will block development of cleaner resources for the 30-year life of the new plants and condemn the state to uncontrolled global warming. Instead, WEM argues that the Commission could address the generation shortage issue by the following: acting though EE matters; making EE a local resource; and making EE show up in supply forecast.

(END OF APPENDIX C)