Decision **PROPOSED DECISION OF ALJ BROWN** **(Mailed 11/16/2004)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004)

OPINION ADOPTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY'S LONG-TERM PROCUREMENT PLANS

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OPINION ADOPTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY'S LONG-TERM PROCUREMENT PLANS

I. Summary

This decision adopts, with modifications, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company's (SDG&E) Long-Term Procurement Plans (LTPP) and provides direction to the utilities on the procurement of the resources identified in the LTPPs. Summaries of the LTPPs are provided as Attachment A.

In our direction to the Investor-Owned Utilities (IOUs) [PG&E, SCE and SDG&E] regarding the procurement of resources to meet identified needs, and in recognition of the substantial amount of procurement to be undertaken as a result of our resource adequacy decisions, we make a number of significant findings. First, following the "loading order" contained in the Joint Agency Energy Action Plan (EAP) is the highest priority, meaning that energy efficiency and demand-side resources should be employed first. When these opportunities are captured, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues a Request for Offer / Proposal (RFO / RFP) for generation resources, it must justify its selection of fossil generation over renewable generation offers. In other words, selection of renewable generation is the rebuttable presumption guiding IOU generation procurement.

We have extended the IOUs' procurement on a rolling 10-year basis. We will diligently oversee how the utilities are using this authority. We authorize the utilities to enter into short-term, mid-term, and long-term contracts, with contract delivery start dates through 2014, provided that the IOUs submit the necessary compliance filings. Furthermore, we have determined that it is time to

allow greater head-to-head competition and hereby lift the affiliate ban on long-term power products. Accordingly, we adopt certain guidelines and safeguards, including an independent third party evaluator (IE) requirement. We will allow the consideration of debt equivalence in the bid evaluation process as specified herein, and we will also require the use of a greenhouse gas (GHG) adder as a bid evaluation component. With these policies we continue to shape and define the hybrid power market in California so as to advance the positive benefits of competition and deliver California's energy services according to the priorities of state policy.

In general, IOUs are directed to procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and we will allow them to credit this procurement towards their Renewables Portfolio Standards (RPS) targets. This is in keeping with the Legislature's clear intent, in creating the RPS program, that renewable procurement be integrated as closely as possible with general IOU procurement practices. To further this effort, we will be working over the course of the next LTPP cycle to fully imbed the RPS into long-term planning, placing renewable energy development where it belongs - central to the IOUs' resource planning efforts. Development of the RPS program will continue in the interim as a high priority for this Commission, and the IOUs will be prepared to issue RPS solicitations in 2005.

To further the state's clear goal of promoting environmentally responsible energy generation, we also adopt a policy that reflects and attempts to mitigate the impact of GHG emissions in influencing global climate patterns. As described in this decision, the IOUs are to employ a "GHG adder" when evaluating fossil and renewable generation bids. This method, which will be refined in future proceedings, will serve to internalize the significant and under-recognized cost of

GHG emissions, help protect customers from the financial risk of future climate regulation, and continue California's leadership in addressing this important problem. Staff will also begin to explore the concept of a carbon content requirement for the IOUs, in coordination with other governmental and non-governmental entities that are addressing the climate change issue.

II. Background

A. Background To Rulemaking (R.) 04-04-003

There are numerous principal sources of guidance regarding what the California Public Utilities Commission (CPUC/Commission) should direct the three IOUs to do in this decision as a response to the LTPP each IOU filed on July 9, 2004: Assembly Bill (AB) 57,[1] EAP,[2] Decision (D.) 03-12-062,[3] D.04-01-050,[4] Order Initiating R.04-04-003, and the Assigned Commissioner Ruling/Scoping Memo (ACR) issued by Commissioner Peevey on June 16, 2004, as amended

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[1] AB 57, (Stats.2002, Ch.850,Sec.3 Effective September 24, 2004). AB 57 added Section 454.5 to the Pub. Util. Code.

[2] Energy Action Plan issued jointly on May 8, 2003, by the CPUC, the California Energy Commission (CEC) and the California Consumer Power and Conservation Financing Authority (CPA). A copy of the complete EAP is available for downloading on the Commission's website at www.cpuc.ca.gov.

[3] D.03-12-062, issued in R.01-10-024, gave the IOUs procurement authority, often referred to as "AB 57 authority" for 2004, including the authority to sign contracts for up to five-years duration for 2005 procurement needs.

[4] D.04-01-050 gave continued procurement authority to the IOUs through the first three quarters of 2005, with authority to sign contracts for up to one year's duration for 2005 procurement needs. D.04-01-050 closed R. 01-10-024, and established the parameters for R.04-04-003.

June 29, 2004,[5] in R.04-04-003. These guidance principles were to be used by the utilities in the drafting and design of their LTPPs.

Specifically, the ACR stated "[a]s indicated in the OIR [R.04-04-003], review and adoption of the utilities' long-term procurement plans is the centerpiece of this proceeding. . . . This exercise, including the adoption of upfront standards and criteria for rate recovery constitutes the last major step remaining for implementation of AB 57. Completion of this review and approval of utility plans by the end of this year is of critical importance so that the utilities can make the investment decisions that are crucial to the reliable energy future of this state."[6]

In summary, that is the purpose of this decision: to give the three IOUs authorization to plan for and procure the resources necessary to provide reliable service to their customer loads for the planning period 2005 through 2014. In addition, this decision also has to work in concert to coordinate and incorporate

[5] The June 29, 2004, Administrative Law Judge (ALJ) Ruling augmented the June 16, 2004, ACR and directed the utilities to include in their LTPPs responses to specific questions regarding global climate change issues.

[6] ACR, June 4, 2004, p. 3.

Commission and legislative efforts from other proceedings, in particular: Community Choice Aggregation (CCA),[7] Demand Response (DR),[8] Distributed Generation (DG),[9] Energy Efficiency (EE),[10] Avoided Cost and Long-term Policy for Expiring Qualifying Facility (QF) Contracts,[11] RPS,[12] Transmission Assessment[13] and Transmission Planning.[14] In addition, on October 28, 2004, the Commission issued D.04-10-035, the Resource Adequacy (RA) decision in this docket.

The OIR instructed the utilities to incorporate the Commission's policy direction from these other proceedings into their LTPPs and to inform the Commission how the utilities intended to meet the established goals from the other proceedings through its procurement decisions between now and 2014. In addition to including these policy directives in their LTPPs, the utilities were directed to prioritize their resource procurements following the "loading order" of preferred resources established in the EAP. The EAP's "loading order" framework identifies certain demand-side resources as "preferred" because they

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7 R.03-10-003.

8 R.02-06-001.

9 R.04-03-017.

10 R.01-08-028.

11 R.04-04-025.

12 R.04-04-026.

13 R.04-01-026.

14 R.00-01-001.

work towards optimizing energy conservation and resource efficiency while reducing per capita demand, as well as certain preferred supply-side resources. The EAP loading order is: energy efficiency and demand response; renewables (including renewable DG); clean fossil-fueled DG; and finally clean fossil-fueled central-station generation. Sensible transmission investments should be made in concert with these other resource commitments.

Because the Commission recognizes that the utilities face many demand and resource uncertainties in planning for the next ten years, the ACR instructed the utilities to prepare three supply/demand scenarios: high-, medium-and low-incremental need. The medium-load plan is to be the preferred resource plan of each utility that meets the needs identified in its Alternative Base Case load-forecast scenario, or its CEC Integrated Energy Policy Report (IEPR) base case scenario. The high-load plan should be a reasonable guess at how great the burden of service could become under high future growth load and an optimistic view of economic growth, assuming modest customer migration for CCA. The low-load should be based on reasonable assumptions about progress in conservation and pessimistic assumptions about the economy and generous assumptions about the development of core/non-core and CCA. The utilities were to use these scenarios to demonstrate how they planned to accommodate the many possible outcomes. Additionally, the utilities were instructed to employ a risk management approach vis-à-vis future commitments by incorporating long, mid and shorter-term contract terms so as to remain flexible to refine resource portfolios as certainty increases.

PG&E, SCE and SDG&E filed their respective LTPPs on July 9, 2004. For the most part, each utility followed the direction provided in the OIR and the ACR for their plans.[15] In particular, each utility prepared the three supply/demand scenarios, incorporated Commission orders and directives from the other related proceedings, planned for a mixed portfolio of resources, contract terms and ownership types and followed the EAP loading order. What is apparent, however, is that the more than twenty intervenors had differing expectations on what the LTPPs ought to include, their function and their relation to annual procurement plans, applications, advice letters and other planning activities—notably transmission planning. Many intervenors complained that the LTPPs did not meet *their* expectations and wanted the Commission to remedy the situation.

In addition, each utility chose differing assumptions regarding their medium case and the boundaries of high and low scenarios. This caused some difficulty in direct comparisons across the three utilities.

What further complicates review of the LTPPs is that much of the detail of the plans is confidential, so some parties identified as "Market Participants"[16]

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15 The June 4, 2004, ACR included an attachment, Attachment A, prepared by the Commission's Energy Division (ED) staff in consultation with staff of the CEC.

16 The protective order signed by the utilities in the 2003 resource planning proceeding, R.01-10-024, defined market participants as follows: "1) an employee of a private, municipal, state or federal entity that engages in the purchase, sale or marketing of energy or capacity, or the bidding on or purchasing of power plants. Or consulting on such matters, or an employee of a trade association comprised of such entities that engage in one or more of such activities: 2) an attorney, paralegal, expert or employee of

Footnote continued on next page

(MP) did not have access to specific forecasts and projections and were only able to respond to the plans in general terms. While members of each utility's Procurement Review Group (PRG) did have access to the confidential files and other intervenors had access pursuant to confidentiality and non-disclosure rules, MPs who did not conform to the terms of the Amended Protective Order[17]did not have such access. The ever vexing and complicated issue of confidentiality and how it relates to ratepayer protection and public access to the Commission's decision making process is addressed further in this decision.

B. Procedural History

The OIR to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning was issued April 8, 2004, the initial Prehearing Conference (PHC) was held April 30, 2004, a second PHC was held August 25, 2004, and evidentiary hearings (EH) were held August 30 through September 24, 2004.

In preparation for the EH, the utilities filed their respective LTPPs on July 9, 2004. Intervenor testimony was received on August 6, 2004, from the Border Generation Group (BGG), Cogeneration Association of California (CAC), California Independent System Operator (CAISO), Calpine Corporation

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an expert retained by an MP for the purpose of advising, preparing for participating in Procurement Plan and Compliance Reviews regarding [IOU]."

[17] On January 14, 2004, the assigned ALJ in R.01-10-024 issued a ruling adopting an Amended Protective Order that was substantially consistent with an order adopted by a Federal Energy Regulatory Commission (FERC) judge in FERC Docket Nos. EL02-60-003 and EL02-62-003, and allowed MPs access to Protected Materials following the FERC guidelines. This Amended Protective Order controlled confidentiality issues in this current proceeding.

(Calpine), California Cogeneration Council (CCC), Center for Energy Efficiency and Renewable Technologies (CEERT), City of Chula Vista (Chula Vista), City of San Diego (CSD), California Manufacturers & Technology Association and the California Large Energy Consumers Association (CMTA/CLECA), Constellation Power Source (Constellation), County of Los Angeles (LA), Duke Energy North America (DENA), California Department of Water Resources (DWR), Independent Energy Producers (IEP), Modesto Irrigation District (Modesto), Natural Resources Defense Council (NRDC), Office of Ratepayer Advocates (ORA), South San Joaquin Irrigation District (SSJID), Strategic Energy and Constellation New Energy (Strategic Energy), The Utility Reform Network (TURN), Utility Consumers Action Network (UCAN), Union of Concerned Scientists (UCS), West Coast Power (WCP) and the Western Power Trading Forum (WPTF).

On August 20, 2004, rebuttal testimony was received from PG&E, SCE, SDG&E, CAISO, Calpine, NRDC, ORA, Strategic Energy, TURN and UCS.

During the almost four weeks of evidentiary hearings there was extensive cross-examination of utility and intervenor witnesses and 128 documents were received in evidence. Post hearing briefs were received on October 18, 2004, from PG&E, SCE, SDG&E, BGG, CAC, CCC, Calpine, CAISO, CEERT, Chula Vista, CSD, CMTA/CLECA, Constellation, DENA, IEP, Modesto, NRDC, ORA, Sempra Energy Global Enterprises (SEGE), SSJID, Strategic Energy, TURN, UCAN, UCS, WCP and WPTF.

Reply briefs were received on November 1, 2004, from: PG&E, SCE, SDG&E, CAC, CCC, Calpine, CAISO, CEERT, Chula Vista, Constellation, DENA, IEP, Modesto, NRDC, ORA, SSJID, Silicon Valley Manufacturing Group (SVMG), Strategic Energy, TURN, UCS and WCP, and a letter was received from the DWR.

The proposed decision (PD) was mailed on November 16, 2004. On November 30, 2004, SCE filed a timely request for Final Oral Argument (FOA) before the whole Commission. FOA was held on December 13, 2004.

C. Motions

During the course of the proceeding numerous motions were filed. Motions regarding requests to strike or limit testimony and/or to exclude exhibits from the record were ruled on orally by the ALJ during the EH. There are a few motions that have yet to receive rulings and they will be addressed. Any motions not previously resolved or addressed in this decision are deemed denied.

UCAN and CEERT filed Notices of Intent to Claim Compensation (NOI) for their participation and contributions to the proceeding. Both of those motions will be ruled on in separate rulings independent of this decision.

On October 8, 2004, WCP filed a Motion for Official Notice, and followed that motion with a supplement on October 12, 2004. In sum, WCP asks the Commission to take official notice of the CEC Committee Draft Report in the IEPR: 2004 Update, dated September 2004 and posted on the CEC's web site. WCP attached a copy of the Committee Draft Report to its motion. In its supplemental filing, WCP advises the Commission that it is not asking the Commission to accept the factual statements in the Report, but rather seeks clarification that all parties may refer to the Report for policy conclusions of the IEPR Committee. At its November 4, 2004 Business Meeting, the CEC formally adopted the 2004 update.

No opposition was received to WCP's motion. The conclusions and policies of the CEC's 2004 Update to the IEPR may be incorporated into the IOUs LTPPs.

On December 6, 2004, San Diego Association of Governments (SANDAG) filed a Motion to Intervene with comments to the PD attached. SANDAG filed its motion pursuant to Rule 45 of the Commission's Rules of Practice and Procedure and requests Interested Party status. SANDAG comprises 18 cities and county governments and serves as the forum for regional decision-making. It seeks to intervene in the LTPP rulemaking so its Energy Working Group (EWG) can work with the community and SDG&E to update the regions LTPP in 2006. SANDAG will strive to involve the community in regional energy planning.

SANDAG indicates that its participation in this proceeding will not prejudice any party, delay the schedule, or expand the scope of this matter.

SANDAG's motion, with attached comments, was filed the day comments were due on the PD mailed on November 16, 2004. While SANDAG's representative was on the service list for the proceeding, SANDAG did not actively participate in the proceeding. With this understanding, SANDAG's motion to intervene is granted, and its comments will be read and considered. However, SANDAG is cautioned that while they are now an Interested Party to the proceeding and may participate as it wishes in subsequent phases of R.04-04-003, this phase of the proceeding was submitted November 1, 2004, with the filing of reply briefs, and the record will not be reopened and the schedule will not be delayed due to SANDAG's intervention.

D. Summary of Parties' Positions

While there were twenty-seven plus[18] active parties to this proceeding, most of the parties can be catalogued into one of the following categories: IOU; consumer/ratepayer advocate; environmental group; municipal/community choice proponent; co-generation facility; wholesale marketer and energy producer, the CAISO and "other." While each party brought a different perspective and advocacy position to this proceeding, there are common threads that connect many of these parties' points of view vis-à-vis the utilities' LTPPs and we summarize those positions below.

1. IOUs

To begin, each IOU had the responsibility for drafting a LTPP that met the criteria established in the OIR, the ACR/Scoping Memo and the EAP. For the most part, the IOUs did not "advocate" a position on their LTPPs, but rather presented them as compliance filings. Within each LTPP, however, there were a few specific positions that a utility took, primarily on the topics of planning and procuring for CCAs, recognition of debt equivalency, future contracting with QFs, length of contracting authority, appropriate policies regarding renewable generation procurement, use of aging power plants/reuse of brownfield sites and whether independent third-party observers were a necessary component of bid solicitations. To summarize the IOUs requests: they each seek approval of their LTPPs and cost recovery assurance.

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[18] Not all parties participated to the same extent. For example, The County of Los Angeles and DWR served testimony, but did not file post-hearing briefs and SEGE did not serve testimony, but filed a post-hearing brief.

2. Consumer/Ratepayer Advocates

TURN, ORA and UCAN, while all consumer advocates, each focused on different topics in the LTPPs. UCAN, for example, only reviewed SDG&E's plan and criticized the plan for not following the EAP's loading order, not addressing Reliability Must Run (RMR) costs, congestion, transmission losses and load pocket needs, using a projected price for natural gas that was too low, failing to extend many short-term contracts that could provide potentially viable resources, especially in regards to EE, DR, DG and renewables—while criticizing the need for a new 500 kilovolt (kV) transmission line.

TURN's primary goal is to have the utilities procure adequate resources for all customers, with *all* customers paying, not just bundled load customers. In point of fact, TURN is concerned that the utilities have too many resources tied up in long-term contracts, and the Commission should enable them to enter into power contracts for terms up to five years. TURN is mindful that the IOUs, in their roles as load serving entities (LSE), want to avoid over procuring in the face of "great uncertainty regarding the magnitude of their future bundled loads."[19] However, TURN is also concerned that if commitments are not made now by PG&E and SCE that new capacity will not be built to be on line by 2008, and the utilities will be left resorting to short-term contracts and the spot market to fill the net-short position—to the detriment of ratepayers. To avert this potential crisis, TURN urges the Commission to order PG&E and SCE, acting as "interim agents" of RA policy on behalf of all customers in the state, to each procure 500 megawatts (MW) of new capacity by contracting with non-IOU generators for periods of up to ten years, with deliveries to start in 2008. The net costs of these resources should be recovered via a non-bypassable charge paid by all customers.

In summary, ORA argues that the following topics do not need to be resolved in *this* proceeding: approval of any transmission plans, especially SDG&E's proposed new transmission line, debt equivalence, a mechanism for comparing power purchase agreements (PPA) with utility-owned generation, use of IEs in the bid solicitation process and stranded costs from customer departing load. Instead, ORA urges the Commission to adopt its aggregate

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[19] TURN opening brief, p. 3.

analysis in the appendix to ORA's report, Exhibits 40 and 41, in drawing its conclusions on the IOUs' planning scenarios, which ORA posits do not differ significantly from the IOUs' conclusions for their procurement needs. In the future, ORA would like to see the Commission address the fact that there were inconsistencies in the use by the utilities of assumptions, especially regarding departing load, and if the utilities used the same forecast assumptions it would be easier to compare and contrast them.

3. Environmental Groups

NRDC, with its interest in minimizing the societal costs of reliable energy services, focused on the delivery of cost-effective EE programs, renewable energy resources and other suitable energy alternatives in reviewing and analyzing the IOUs' LTPPs. NRDC found that the LTPPs lacked adequate information as to whether they would minimize economic and environmental impacts, failed to follow the EAP's loading order, did not compare different generation resource options and did not adequately address carbon dioxide emissions. To remedy these deficiencies, NRDC urges the Commission to require the IOUs to account for the financial risk associated with carbon emissions; develop a strategy to reduce global warming pollution emissions; plan and procure renewable resources above and beyond the minimum established in the RPS; and implement policies on investing in EE and renewable resources.

CEERT shares similar goals with NRDC, such as improving air quality and reducing dependence on fossil fuels. CEERT found PG&E and SCE's LTPPs to be deficient especially regarding their renewable procurement plans and asks that the Commission direct these two utilities to supplement or amend their plans to be consistent with that submitted by SDG&E. CEERT would like to see a more detailed analysis from PG&E and SCE as to how they intend to reach their RPS goals, more information as to the specific resource profiles they intend to procure, similar to the "portfolio stack" submitted by SDG&E, an incorporation of each utility's goals concerning the environment and a ten-year planning horizon so the renewable industry can plan ahead. Even though many other parties criticized SDG&E's inclusion of a 500 kV transmission as part of its LTPP, CEERT applauds the proposed line as a means to bring more renewables into the SDG&E service territory. Although PG&E and SCE justified the ambiguity in the renewable portion of their LTPP as to an actual renewable portfolio stack on the ground that the market would decide the portfolio stack, CEERT argues that PG&E and SCE have sufficient information from previous RPS RFO/RFPs to make more detailed projections than they did.

UCS also did not find the IOUs' LTPPs sufficient for demonstrating the utilities' commitment to climate change and related topics and asks the Commission to require supplemental filings that model potential cost impacts of carbon regulation and gas price risk, along with a more detailed analysis of renewable resource potential over the next ten years. In addition, if the Commission adopts a debt equivalency factor for long-term contracts, UCS requests that the factor for renewables be lower than for non-renewable, and that the IOUs incorporate the EE goals adopted in D.04-09-060. In particular, UCS urges the Commission to insist that the IOUs account for the cost of emissions associated with particular resource choices.

4. Potential CCA/Municipalization/Direct Access

Five intervenors could be described as parties representing potential "departing load" by way of CCA, municipalization, direct access (DA) or a core/non-core structure; Chula Vista, Modesto, SSJID, Strategic Energy and CMTA/CLECA.

These parties are all particularly concerned that the IOUs will over procure and then departing customers will be obligated to pay for their share of stranded costs so their departure will not over burden the bundled ratepayers remaining with the utilities. Chula Vista wants SDG&E to include CCA for the city as a likely case scenario, and only use short-term contracts to fill in for any net short in the near term. SSJID plans to provide service to its irrigation district customers in January 2007 and wants PG&E's LTPP to recognize this so PG&E does not procure energy for these customers. Modesto finds itself in a similar situation to SSJID and urges the Commission to instruct PG&E to make "wise" procurement decisions by using short-term power contracts to meet its 90% year ahead obligation, so there is no need for the non-bypassable surcharge. Modesto argues that changing weather conditions alone cause more fluctuation than Modesto's departing load, and so PG&E should not look to Modesto's customers for the collection of stranded costs.

CMTA/CLECA also want the IOUs to be mindful of over-procuring in light of the uncertainty of departing load for DA or a core/non-core structure and want the utilities to minimize the risk of stranded costs by using a mix of contract lengths. From CMTA/CLECA's perspective, it is the IOUs responsibility to plan properly, so there should be no non-bypassable surcharge. CMTA/CLECA recognize that there might have to be limits on departing load, such as annual limits on net migration to or from the utility, but advocate there should be no surcharge. CMTA/CLECA also want more access to confidential IOU data [see discussion under "Confidentiality"], support an open and transparent RFO process and support the use of an IE for the RFO if an affiliate is involved in the bidding.

Strategic Energy is also concerned with the utilities over procuring and argues that the IOUs did not make reasonable assumptions in their LTPPs about departing load for CCA/DA/core/non-core and therefore if there are stranded costs, the utilities should be at risk. From Strategic Energy's vantage point, the IOUs' failure to properly plan for departing load almost ensures that any migration of load will result in stranded costs. Strategic Energy urges the Commission to not institute any charge for departing customers as that removes risk from the utilities for over procurement, removes any incentive for the utilities to resell excess power, gives the benefit of increased reliability to bundled customers at the expense of departing load customers and frustrates competition by slowing down migration.

5. Co-Generation Facilities

CAC and CCC are concerned with the inclusion/exclusion of QF contracts in the IOUs' LTPPs. While CAC and CCC understand that the Commission is not determining the future fate of QFs in this proceeding, they still argue that the Commission must insist that the IOUs reserve a place in their LTPPs for QFs as baseload resources and to sign up to five-year contracts with these resources. Both co-generation associations fear that the IOUs will be fully "resourced" without any QF contracts in excess of one year. Without longer-term contracts the QFs might not continue to exist, and because of their unique properties they cannot participate competitively in an RFO that is not seeking base load power. None of the utilities anticipate needing baseload resources in the near term. Instead, their projected need is for dispatchable peaking or shaping resources. Co-generation QFs run 24/7 to supply their hosts, and without a contract to sell that 24/7 power they would have to use steam boilers to meet their host's needs.

6. Energy Marketers and Independent Energy Producers

WCP, WPTF, IEP, DENA, Constellation, BGG and Calpine are all identified as MPs and as such did not have unfettered access to the IOUs' confidential data supporting their LTPPs and referenced this information deficit in their briefs. Refer to the section in the decision on Confidentiality for further discussion. However, even without reviewing the confidential background data for the LTPPs these MPs were able to effectively cross-examine the IOU and intervenor witnesses and advance their position.

WCP, IEP, DENA and BGG all focused on the need for long-term contracts and an open and transparent solicitation process. BGG supports SDG&E's proposed new 500 kV transmission project because it would increase import capability and system reliability, decrease RMR costs and give access to out-of-area resources, including renewables. DENA, on the other hand, argues against SDG&E's 500 kV transmission project and wants the Commission to direct the utility to explore more in-area generation. Specifically, DENA could re-power its South Bay facility in the same time frame as the new transmission lines, if it can compete in a RFO for a three to five year contract.

WCP advances similar arguments to those of DENA: the Commission should recognize the value of aging power plants as providing needed RMR, peaking and intermediate power in the three to five year range, and most importantly, recognizing the value of using existing brownfield sites for new generation facilities - especially before approving a new 500 kV transmission line. All costs should be considered in comparing brownfield sites with greenfield sites, especially those that are hard to quantify, such as location near the load pocket, and WCP even argues that brownfield sites should be given a recognized priority in the loading order. WCP contends that building on a brownfield site is cheaper than building a new combustion turbine (CT) or combined cycle (CC) facility, provides deliverability without long-distance transmission and provides reduced costs to society as compared with the siting of a new location.

IEP favors a fair and equal field for competitive bidding and recommends that the Commission not adopt a debt equivalency factor for bid comparisons, allow short-term capacity procurement and utilize an IE to monitor an RFO when there are competing bids from PPAs and utility-owned projects.

Calpine, WPTF and Constellation all advocate for an open, fair and competitive RFO process with some protections to keep the playing field level for PPAs competing against utility owned projects. First and foremost, they argue vociferously against establishing recognition of debt equivalency as part of the bid evaluation. Under almost all scenarios where debt equivalency is a factor, all bids except the utility-owned option fail the least-cost best-fit (LCBF) criteria. Next, Calpine wants any IOU bid to be a binding commitment with the shareholders, not the ratepayers, at risk for overruns. Then, the Commission should allow long-term contracts, not just short-term as the CCA/DA intervenors request, because the marketers and IPPs need the financial security of long-term contracts to get the financing to refurbish old facilities and to build new resources. And, finally, no preference should be given to any bid outside of those preferences established by the EAP, Commission decisions or the legislature.

WPTF also proposes a tradable capacity market because then there would be no need for a non by-passable surcharge for departing load. WPTF recommends the use of an IE if a utility option is one of the bids and wants utility winning bids to be binding and non-recourse, with no cost overruns.

Constellation is in favor of a competitive wholesale market and proposes a “slice of load” concept or standard offer service (SOS) that would be a three to five year contract for wholesale services, bid through a competitive process, with Commission oversight, where the marketer would bid for a percentage of the utility's load and take the risk as the load varies from time to time. The risk of customer uncertainty would be borne by the marketer, not the IOU, so there would be no stranded costs. Constellation urges that this concept would provide ratepayer benefits from competitive prices, diversity of supply, elimination of stranded costs, alignment of customers and utility and application of market rules. The SOS would also include RPS and RA requirements.

7. The CAISO

CAISO finds the IOUs' filings insufficient for its purposes. The CAISO needs the location of a potential resource, the conceptual scenario for resource additions, and the identity of potential new resources and transmission needs. CAISO wants the IOUs to include a with/and/without scenario for new transmission in future LTPPs.

8. Other Intervenors

CSD and SEGE are also intervenors in this proceeding but do not fit into the above categories. CSD focused exclusively on SDG&E's LTPP and argues against approval of the 500 kV transmission line until there has been adequate time to weigh alternatives. The goal of CSD vis-à-vis SDG&E is to advocate for cost-effective reliability through a balance of customer-owned and utility-owned generation plus procured generation. CSD does not see enough flexibility in SDG&E's plan for departing load, sees too much out-of-area renewable power at the expense of local renewable DG, and is not in favor of allowing the utility to meet its RPS through renewable energy credits (REC) unless the RECs have been procured from DG with net-metered renewable generation.

SEGE argues for the Commission to rescind the ban on affiliate transactions since it prevents the utilities' from access to ready built facilities if owned by an affiliate. In addition, SEGE favors competitive solicitations, including for utility-owned generation and affirms the public policy of prudent IOU procurement so as to reduce risk of stranded costs.

III. Analysis Of Long-Term Procurement Plans

A. Do The LTPPs Integrate The Commission's Direction From Other Related Proceedings And Meet The Criteria Established In The ACR/Scoping Memo?

1. General Assessment

PG&E, SCE and SDG&E each used its resource plan to inform the procurement decision, rather than to select a deterministic set of resources or to identify specific procurement actions. The IOUs interpreted the directions for preparing the scenarios as guidance for presenting the background for, and illustrations of, their procurement strategies. The IOUs' resource scenarios demonstrate the impact of key uncertainties and how resource plans can be structured to deal with these risks. The utilities request procurement and cost-recovery rules for their LTPPs.

In reviewing the resource scenarios in the LTPPs, each intervenor brought a particular perspective to its analysis of the plan that tended to highlight individual features. For example, intervenors concerned with departing load are concerned that the IOUs are over resourced in general and that could lead to stranded costs if/when there is departing load. Other intervenors focused on whether the resource scenarios plan for sufficient energy efficiency, demand response, renewables and DG.

2. Directions for Load Forecasts and Resource Scenarios

Before reviewing load and resource assumptions, we need to set the stage by discussing the overall role of resource scenarios as a backdrop to the procurement plans. There are four principal sources of guidance regarding what this decision should direct the IOUs to do as a response to their LTPPs: the EAP; D.04-01-050; the April 4, 2004 OIR (R.04-04-003); and the June 16, 2004 ACR/Scoping Memo as amended on June 29:

"The OIR is clear that the major focus is to review and adopt long-term *procurement* plans. However, the plans must be based on an integrated resource strategy that is consistent with Commission policy, reflects reasonable assumptions, and covers a rational range of scenarios."

The June 4, 2004, ACR (Appendix A) directed the IOUs to prepare resource scenarios as follows:

> *The Medium-Load Plan Scenario.* The medium-load plan is to be the preferred resource plan of each utility that meets the needs identified in its Alternative Base Case load-forecast scenario or, if the utility does not choose to file an Alternative Base Case load-forecast scenario, its IEPR-CEC base case scenario. This Plan is to be a utility's best estimate of how it would prepare to meet the needs it believes ultimately will come to be. Though it is not necessary, or even possible, for utilities to specify in detail the placement of new generation facilities that may be needed up to ten years in advance, nor is it possible to indicate the specific paths of transmission additions or upgrades, it is appropriate that the utilities be more specific than they were in the Long-Term Plans submitted in 2003.
>
> *High-Load Plan Scenario.* The High-Load Plan is not to be an extreme case that has little chance of coming to pass. Rather, it should be a reasonable guess at how great the burden of service could become under high, but not unreasonable assumptions about future load growth. The Plan should be based on the assumption of greater than expected economic growth, resulting in higher load growth, assumption of a modest core-noncore load loss beginning only in 2009, and a modest development of CCA, also beginning in 2009. The utilities should assume that current levels of DA will continue throughout the time horizon.

> *Low-Load Plan Scenario.* The Low-Load Plan similarly, is not to be an extreme example of conservation and changed priorities of Californians. Rather, it should be based on reasonable but pessimistic assumptions about the economy and on generous assumptions about the development of core-noncore impacts and CCA. Assume aggressive CCA development beginning in 2006, and an aggressive core-noncore scenario from the choices discussed above. Again, assume the continuation of DA service at current levels.

B. Load Forecasts

1. Position of IOUs

PG&E asserts that it complied with the directions of the ACR, and that no party directly challenged PG&E's reference case (i.e. service area forecast) or its high, medium and low forecasts.[20] In its medium case, PG&E assumed that three percent of its current customers with load under 500 kW will begin to migrate to community choice aggregation in 2006, and the rate of loss to this market will increase by one percent annually, reaching 10 percent in 2013.[21] PG&E also assumed implementation of a core/noncore market structure beginning in 2007 and that 50 percent of noncore customers with load above 500 kW who are not already direct access service customers will depart from PG&E service.[22]

SCE contends that its forecasts are reasonable and that they comply with the ACR requirements. Since SCE's medium case, its preferred case, did not include any CCA or core/non-core, it was the focus of most discussion. SCE

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[20] PG&E opening brief, p. 7.

[21] Ex. 34, PG&E/Aslin, p. 4-7.

chose a forecast that was "consistent with Edison's current load forecast, without knowledge of what might come."[23] This is also the forecast used in SCE's 2006 General Rate Case, adjusted for expanded EE. SCE's low load case assumes low economic growth and aggressive departing load.

SDG&E asserts that its (area) load forecast was unchallenged in this proceeding. "The medium-load plan represents SDG&E's best estimate of the resources needed to reliably serve its customers, and it is based on a load forecast that does not show any loss of load to a core/noncore split or CCA implementation. Given the uncertainty surrounding the timing and magnitude of emerging rules for CCA, core/noncore, or reinstatement of direct access and the potential resulting outcomes, the medium-load plan is best suited to meet the expected need absent firm, enforceable commitments and other final details to assess departing load models."[24]

All three IOUs included current levels of direct access throughout the planning horizon and did not plan for the return of self-generation customers.

2. Position of Parties on Load Forecasts

ORA conducted a thorough review of the service area load forecasts, noting that the growth rates are similar to those in the CEC's 2003 IEPR, but adjusted to fit the higher actual growth in 2002 and 2003. ORA found the service

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[22] Ex. 34, PG&E/Aslin, p. 4-7, PG&E opening brief, p. 7.

[23] SCE/Whatley Tr. Vol. 11, 1602:16 – 1603:14.

[24] SDG&E opening brief, p. 11.

area load forecasts reasonable.[25] ORA also examined the differing departing load scenarios and recommended that the IOUs use ORA's common set of departing load assumptions.

CMTA/CLECA found the IOUs' medium case differences in the treatment of departing load sufficiently troublesome to ask that the Commission direct parties to rerun their scenarios using a common set of assumptions. They also urge the Commission to only place a low level of confidence in the medium case scenarios.[26]

Calpine recommended that a 1-in-10 peak weather planning standard be used for all demand forecasts, as is required for local reliability transmission studies. This would add about six percent to the demand forecasts.

CCA asked for and received assurance from all the IOUs that existing load served by large co-generation was assumed to be continued to be served by self-generation and had not been included in the demand forecasts.

Several parties, such as Modesto Irrigation District, South San Joaquin Irrigation District, and the City of Chula Vista, asked that the load in their jurisdictions be removed from IOU demand forecasts, because they intend to serve the load themselves.

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[25] ORA Testimony, EX 41C, pp 1-16. "C" after an exhibit indicates that it is a "confidential" exhibit and only parties who are members of the PRG groups or who signed the protective order have access to the confidential version.

[26] CMTA/CLECA opening brief, p. 3.

3. Discussion of Load Forecasts

The “service area” or “reference” medium forecasts presented by the IOUs in their LTPPs indicate reasonable growth trends and levels. The utilities use similar growth factors and are generally consistent with the IEPR forecast trends, except the levels are higher because they are updated from a 2001 baseline to a 2003 baseline. This update reflects the unanticipated economic recovery in 2002 and 2003 that was not reflected in the IEPR forecast.

The most obvious disparity between the IOUs’ forecasts was in the area of assumptions about departing load for DA, core/non-core and CCA. PG&E does include departing load projections in its baseline forecast, where SCE and SDG&E do not. Potentially, PG&E’s baseline could be too low, whereas the other IOUs’ baselines could be too high. Parties representing potential departing load, and the energy marketers hoping to serve the departed load, questioned whether SCE and SDG&E’s medium load scenario included sufficient assumptions about departing load.

The ACR required that the medium load forecast be the utility’s preferred case and its best estimate of how it would prepare to meet the needs it believes ultimately will come to be. Since CCA has been set in statute and is the subject of an on-going CPUC implementation proceeding, it is reasonable that some CCA will start to occur in 2006. But, there was not sufficient evidence in this proceeding that CCA alone will have a material effect on IOU resource needs in the next few years.

The future of expanding DA or creating a core/non-core market is more speculative. DA is currently suspended by legislation until the last DWR contract expires, currently scheduled for 2013. There is no record on which to base a choice on the probability that more retail competition will emerge.

As a consequence, we should take these demand uncertainty factors into account as one of the uncertainties affecting the level of acquisition and the need for flexibility in the resource plan. However, we are not going to adopt a fixed assumption regarding a most likely set of departing load. We acknowledge that the IOUs face considerable load variability risk, and will set policies accordingly.

We will not set a procurement cap based on the low cases, since this could seriously under-resource California's service areas during the planning period. Instead, we will rely on a portfolio approach and allow justification of specific contract types as the need arises. This will allow us to balance between obtaining adequate resources and not over-procuring in the case of departing load or crowding out of preferred resources towards the end of the planning period. We will monitor how the IOUs are doing on obtaining resources to meet their resource adequacy requirements on a forward-looking basis.

We disagree with Calpine that all demand forecasting should switch to the 1-in-10 peak weather standard used for testing the robustness of local transmission systems. Existing resource planning uses average weather (1-in-2) and then adds a reserve margin which, in part, provides the cushion should hotter than average weather occur. This is the approach we adopted to implement our resource adequacy requirements.[27] Calpine's concern is already accounted for in existing practice.

In summary, although each IOU prepared its own LTPP using its own assumptions, each IOU asserts that its service area load forecasts are comparable to the IEPR, adjusted to more current data, and that their medium, preferred case is a reasonable basis for resource planning. We find that all three LTPPs are consistent with the 2003 IEPR, are reasonable for planning purposes and that the medium, preferred case should be followed for making planning and procurement decisions.

C. Implementing the Energy Action Plan

The EAP contains explicit direction regarding the state's preferences for meeting identified resource needs, and the IOUs are to prioritize their resource selections accordingly. As discussed earlier in the decision, the EAP "loading order" is as follows: energy efficiency and demand-side resources; renewable generation resources (including renewable DG); clean fossil DG; and efficient, clean fossil generation resources. Sensible transmission investments should be made in concert with these other resource commitments. Sections of this decision describe the objectives and guidelines for investments in efficiency and demand-side resources; give direction for aggressive procurement of renewable generation resources; present instructions for procuring clean fossil resources and discuss transmission and DG, respectively. The direction is clear: IOUs should implement the EAP loading order when soliciting resources as a result of this decision.

D. Net Open Positions

After existing resources and policy preferred resources have been compared to load and necessary reserves, the remaining gap is the amount of energy and capacity which an LSE must still acquire. This is called either "need"

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[27] D.04-01-050 and D.04-10-035

or the "net open position" (NOP), sometimes subdivided into "net short" and "net long." Actual forecasts of NOP and energy were contained in confidential filings, so discussion in the testimony and hearings is general. The utilities vary or are unclear about whether they requested adoption of a Residual Net Open level as a floor or ceiling for procurement.

1. Position of IOUs on Net Open Positions

PG&E asserts that its NOP is reasonable. Based on the three scenarios PG&E developed, PG&E estimated the energy and capacity it will need to fill its NOP.

"For the first five years of PG&E's medium load scenario, PG&E's energy and capacity needs show little change because anticipated load growth and resource attrition are offset by projected load migration to the community choice aggregation and core/noncore markets. PG&E's energy and capacity needs begin to increase in the latter years of the 10-year planning horizon as the DWR contracts allocated to PG&E begin to expire."[28]

In PG&E's high-load scenario, PG&E's energy and capacity needs become increasingly greater throughout the planning horizon. In PG&E's low-load scenario, its NOP grows longer during the first five years of the plan, but becomes increasingly shorter during the latter half of the planning horizon.[29] PG&E's NOP is not affected by transmission additions, because PG&E did not propose any economically-driven transmission lines in its LTPP.

"SCE's current supply portfolio is dominated by long-term and baseload resource commitments. Such a portfolio results in SCE having excess supply that must be sold into the market."[30] There is a need for additional load-following and peaking resources.

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[28] (Ex. 34 and 35 C, Tables 4-3 and 4-4.)

[29] PG&E Exs. 34 and 35C, Tables 4-3 through 4-8, PG&E opening brief, pp. 16-17.

[30] SCE opening brief, Appendix A, p. A-7.

Due primarily to the suite of grid reliability resources approved in D.04-06-011, SDG&E is essentially "fully resourced" through approximately 2009. Combined with efforts to achieve 20% of the energy mix by 2010 from renewable sources means SDG&E will primarily procure only renewable power until 2010. Nevertheless, SDG&E asks the Commission to take precise and specific action to address future needs identified in SDG&E's medium-load plan. Increased grid reliability needs, for example, appear in 2010 in the medium load plan due to load growth and limited in-basin generation. In addition, the presence of the DWR Sunrise contract in SDG&E's portfolio means that SDG&E does not have 'headroom' until after 2010 to obtain further local reliability contracts.[31]

2. Discussion of Net Open Positions

In summary, all three IOUs have capacity needs throughout the planning horizon. Capacity needs expand considerably in 2011, due to the expiration of most of the DWR contracts. All three IOUs are long on energy, primarily in the off-peak and shoulder hours, through 2009 (PG&E) and 2010 (SCE and SDG&E) until the bulk of DWR contracts expire. Because resources are 'lumpy', adding preferred resources upon existing resources somewhat exacerbates this long position, requiring utilities to be energy sellers in many off-peak and shoulder hours.

This Commission favors openness in its decisions and in the information that market participants have in dealing with each other. Another section of this

[31] SDG&E opening brief, pp. 16, 18.

decision discusses specifically how we are responding to legislative direction on confidentiality matters. In this section we note that it is not the intent of the Commission to provide the means by which market power could be exercised against the LSEs and, hence, against electric service customers in California. Therefore, this decision does not present information about the current NOPs of the utilities. Nor do we provide the elements from which that information can be calculated. However, we will provide simplified tables based on projections of future resource balance information for the years 2007-2014 after those numbers have been refreshed from their initial filing in July.

E. Resource Scenario Compliance

Parties disagreed on whether the resource scenarios complied with the Commission's direction in the OIR and Scoping memo. The parties that requested more detailed filings, seemed to be evoking the detailed resource assessments and specific direction that took place when utilities were monopoly resource suppliers. In today's hybrid market, the utilities can propose which characteristics would best fit Commission direction and current circumstances, but only market-tested bids within the framework of the loading order, will actually produce a portfolio of specific resources. In this setting, planning is indicative, not deterministic.

Although all three IOUs relied on different assumptions in modeling their medium case and in setting floors and ceilings for the high and low scenarios, for the most part the three LTPPs complied with the resource scenario request. The differing assumptions made cross-utility comparisons difficult, but each LTPP taken on its own provided a reasonable range of scenarios as boundaries of risk.

1. Resource Scenarios and Resource Adequacy

As set forth in the April 1, 2004 OIR, the purpose of the three resource scenarios was to "help the Commission understand how each utility intends to respond to a wide range of load scenarios. The focus is not on forecasts, but rather on the adoption of long-term plans that can accommodate many possible outcomes."[32]

The IOUs filed their LTPPs, with resource scenarios, on July 9, 2004, almost four months before the Commission issued its decision on Reserve Margin Requirements/Resource Adequacy (RMR/RA) in D.04-10-035 on October 28, 2004. At the time the LTPPs were prepared, the IOUs and many intervenors were concerned with the utilities overprocuring resources—especially in the short-term. However, pursuant to the direction given by the Governor Schwarzenegger and President Peevey, and adopted by the Commission, the current focus is on maintaining and enhancing grid reliability through accelerated reserve margin targets. When this goal is integrated with the directive from D.04-07-028 issued by the Commission this summer ordering the utilities to concentrate on near-term reliability, it is evident that the IOUs must increase and retain supply (or decrease demand by equivalent amounts) for the near future. We will try to balance grid reliability with our other primary public duty of protecting ratepayers from excessive charges but also be mindful of potential departing loads and the possibility of stranded costs.

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[32] R.04-04-003, *mimeo.*, p. 4.

The IOUs did not have the benefit of the RA decision when the scenarios were prepared in July 2004 and it may be necessary to direct the IOUs to update their LTPPs to comply with the new reserve margin targets.

2. Position of IOUs on Implications of Resource Scenarios

As an appropriate segue, in its LTPP, PG&E states that it is most concerned about the resource risks associated with customer load uncertainty and the risk of stranded costs due to excess procurements. IOUs devoutly wish to avoid being "over-resourced," but procurement strategies based on short-term procurement and dependence on external suppliers have even greater risk, as the energy crisis demonstrated. PG&E's integrated resource plan is designed to recognize these tradeoffs by requesting (1) the full implementation of AB 57, as called for in the April 2004 letter from Governor Schwarzenegger to President Peevey; (2) approval of its low-case scenario and (3) recognition of the possibility of a non by-passable charge if long-term procurement commitments are stranded. In addition, PG&E suggests that the "hybrid market structure" already approved by the Commission, would all facilitate competition by ensuring that: (1) LSEs share the costs of long-term commitments; (2) bundled customers are indifferent to the departure of load to competitors; and (3) new resources are developed.[33]

PG&E urges the Commission to approve its resource assumptions, medium-case load forecast scenario, and portfolio strategy. All of these together implement the EAP loading order cost-effectively and fill PG&E's projected NOP with "preferred" resources and a mixture of short, medium, and long-term

[33] PG&E opening brief, p. 5.

products. The utility argues that the Commission should ignore self-interested proposals from other parties that could force the utilities to procure resources that are unneeded or would not be cost-effective. "The Commission should find that PG&E may procure 1,200 MW of long term peaking resources by 2008 and an additional 1,000 MW of long term shaping resources by 2010. . ."[34] These levels are based on net open needs identified in PG&E's low load scenario. PG&E also requests that the Commission re-authorize short- and mid-term contracts, in order to have a robust portfolio. Additionally, depending on resource need, PG&E may enter tolling contracts with existing resources and bilateral agreements with generators after they are no longer needed for RMR support as well as with generators whose current contracts with DWR expire within the planning period.[35]

SCE states that under its scenarios:

- SCE's expanded demand-side portfolio is cost-effective in every scenario, but must be adapted based on SCE's bundled customer needs;
- SCE will meet the EAP's accelerated renewables target in every scenario, and under the low load scenario SCE has no need for additional renewable generation until 2012;
- SCE has no need for baseload resources until at least the end of the decade and even later, under the core/non-core scenario;

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[34] *Id.*, p. 2.

[35] *Id.*, pp. 20-21.

- SCE's current resource portfolio is overweight with long-term resources (greater than 5 year commitments) whether measured by capacity or energy. This situation is even more pronounced under core/non-core scenarios;

- SCE's current resource portfolio is overweight with baseload resources in the near-term and requires balancing with peaking resources; and

- When compared to today's resource mix, SCE will require more peaking and intermediate resources and less baseload resources in the future.[36]

SCE seeks to minimize the financial risk of such [excess baseload] resources to bundled customers by committing only to short- and medium-term peaking and intermediate resources. The multiple scenarios SCE presented in its LTPP all indicated that SCE would follow this strategic path forward regardless of the changes to its load.[37]

Originally, SCE had requested authority only for short- and mid-term contracts of 5 years or less, but in its reply testimony it outlined a proposal for a 10-year contract if there could be off-ramps for specific purposes, such as greater than expected departing load. This option was added, in part, due to requests by parties that SCE enter some long-term contracts. SCE proposes to pursue this option in a future application to amend its procurement plan.[38]

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[36] SCE opening brief, pp. 9-10.

[37] *Id.*, p. A-7.

[38] SCE/Cushnie Tr Vol. 10, 1539:23 – 1540:2

SDG&E claims that its resource plan does not assume that the exact size, timing, and sequence of each specific future resource addition be etched in stone through approval of this plan. Instead, SDG&E argues that approval of its resource plan, tested under a variety of scenarios, provides a critical first step to subsequently bringing forward specific resources for Commission approval. Adoption by the Commission of SDG&E's long-term plan would therefore constitute the Commission's agreement that the portfolio of resource types identified in this long-term plan represent desired outcomes for customers, and that SDG&E's moving forward to further study and permit the additions shown in the plan is consistent with Commission policy.[39]

SDG&E argues that the Commission should approve its medium-load plan because it is SDG&E's best estimate of how it can prudently and reasonably prepare to meet its customers' needs over the next ten years. SDG&E's medium-load plan fully reflects the Commission's preferred loading order that first takes into account cost-effective EE, DR, and renewable sources of energy before consideration of supply side resources and transmission.

For SDG&E, a key component of its long-term resource plan is its proposed 500 kV transmission line and it is seeking Commission support on this concept as part of its LTPP approval. The utility does acknowledge that it will still have to file a CPCN application for the transmission line. The CPCN proceeding will, among other things, consider the trade-off between transmission and generation, which was an analysis that numerous parties specifically mentioned. SDG&E argues that this analysis need not have to be

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[39] SDG&E opening brief, pp. 2-3.

done at this stage, however, and it does not prevent the Commission from concluding now that new transmission is a key component of SDG&E's long-term resource plan that needs to be further analyzed.[40]

3. Position of Parties on Implications of Resource Scenarios

To summarize, each party reviewed the IOUs resource scenarios under the microscope of their own perspective and asks for Commission action to promote that viewpoint. Those concerned with reliability and marketing power to the IOUs tended to argue in favor of more resources; those concerned with the environment, renewables, conservation and generally reducing demand for power wanted the IOUs to concentrate more on EE, DR, DG and renewables and less on fossil-fuel resources; proponents of brown sites advocated giving more priority to aging power plants; potential departing load parties worried the IOUs were over procuring, and consumer/ratepayer groups, while advocating reliability, question "at what cost?" Parties recommended a mix of contract terms from short-term ones to reduce the possibility of stranded costs, to long-term contracts to capture some certainty for prices in the future.

4. Discussion on Implications of Resource Scenarios

The IOUs complied sufficiently with Commission direction in preparing their resource scenarios so we will not require the preparation and resubmission of LTPPs at this time. What we glean from deficiencies in these LTPPs can be addressed by requesting updates as the Commission gives new instruction or

[40] *Id.*, pp. 45, 47.

clarification in other resource/procurement proceedings and can direct us in giving guidance for the next LTPP proceeding.

In general, the three IOUs and the more than twenty-seven intervenors recognized that the resource scenarios represented “best guesstimates” and there is no way to predict the energy demand/supply situation with complete certainty, especially in the face of changing load situations. A mix of resources, fuel types, contract terms and types, with some baseload, peaking, shaping and intermediate capacity, with a healthy margin of built-in flexibility and sufficient resource adequacy, is the best the IOUs can do at this point in time. The IOUs need to balance expiring DWR contracts with required targets in EE, DR and renewables, so they are not overresourced during the ten-year planning period with no room for adjustment based on changing market conditions.

We provide the following guidance on meeting the identified IOU needs in accordance with the EAP loading order and the GHG adder adopted in this decision. When executing procurement plans in response to the direction below, each IOU is to take the following steps:

- Procure the maximum amount of cost-effective EE and demand-side resources, as determined in the subject-area proceedings;
- For further resource needs, procure the maximum cost-effective amount of renewable generation resources via all-source RFOs, and be prepared to justify selection of fossil over renewable resources; and
- Employ the GHG adder, described in this decision, when evaluating fossil generation bids.

We find reasonable PG&E's strategy of adding 1,200 MW of reserve and peaking capacity in 2008. We find that an additional 1,000 MW of new peaking and dispatchable generation in 2010 through RFOs is compatible with their medium resource needs, that it does not crowd out policy-preferred resources, and is a reasonable level of commitment given load uncertainty. However, these commitments may need to be increased or expedited for PG&E to meet its 2006 resource 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.

We find SCE's LTPP resource plan reasonable, subject to the compliance requirements covering its demand forecast, DR, EE 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 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 such a case to the Commission as an implementation of its LTPP by way of an application following an RFO.

SDG&E's resource scenarios were the most complete and useful in understanding the impact of differing loads, risk strategies and the complex process of compiling a portfolio that meets reliability, adequacy, policy preferences and cost moderation goals. We find SDG&E's resource plan reasonable, subject to the modifications required for the compliance filing.

SDG&E is essentially fully resourced through 2009, other than needed investments in renewable resources to meet RPS targets. Because SDG&E is fully resourced, SDG&E's resource plan is vulnerable to departing load and the utility is still obligated to meet its renewables, EE and DR goals. Since SDG&E's estimated reserve margins, which exceed 17% in some years during the planning period are the result of prior Commission decisions, there should be no finding of unreasonableness if they exceed 17%.

One critical element of SDG&E's LTPP that we are not approving in this decision is their request for a 500 kV transmission line. As we discuss elsewhere, we do acknowledge the lengthy process that is needed to plan, license and construct transmission, and thus encourage SDG&E to continue its planning efforts and move forward with evaluating these transmission alternatives for creating strategic and economic net benefits and meeting a potential local resource deficiency by 2010, as well as for securing sufficient resources to meet renewable generation targets.

For this round of procurement filings, we find that the IOU filings are EAP-compliant to the extent they include EAP targets established in the RPS, DR and EE proceedings; included, at a minimum, the DG forecasts in the 2003 IEPR, and added transmission and clean central-station generation to meet remaining energy and capacity needs.

We will direct a compliance filing of annual energy and capacity resource accounting tables, consistent with directions on baseline load forecasts, EE, and DR as explained elsewhere in this decision, but we will not require refiling of whole resource plans. However, we do expect the IOUs to make incremental improvements in their next round of analysis to be filed with the Energy Commission in its 2005 IEPR process. Procurement resulting from the plans should comport with the direction, above, regarding obtaining the maximum feasible amount of renewable generation.

We concur with the CAISO that the transmission elements of the plans were insufficient to meet our goals and accept their recommendations that future plans should include conceptual scenarios that illustrate the impact of potential generator location. We also concur that when an IOU proposes a major transmission line, it should include a companion scenario without the line. To the extent an IOU believes that the range of need identified in the 2005 IEPR is sufficient to justify a transmission project then it may be identified as a specific proposal to satisfy need in the 2006 procurement proceeding filings.

F. Natural Gas Price Forecasts

1. Regulatory Background

The May 2003 EAP, D.04-01-050, R.04-04-003 and the June 4, 2004 ACR all provided guidance to the IOUs on the subject of natural gas price forecast issues. R.04-04-003 reiterated the EAP's message that the IOUs were to "[f]irst seek to optimize all strategies to increase conservation and energy efficiency in order to *minimize increases* in electricity and *natural gas demand.*"[41]

> "Long-term plans should reflect the most recent fuel-price forecasts available at the time of the plans' preparation and should include fuel-price variation as an element of the plans. We are not convinced that the actual degree of potential variation in fuel costs was reflected in the cost scenarios presented in the long-term plans. Therefore, we caution the utilities to consider seriously the degree of volatility that should be expected in fuel prices when developing high percentile scenarios for procurement costs particularly. We

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[41] R. 04-04-003, p. 6, emphasis added.

> direct that future long-term procurement plans should reflect fully the expected range of prices of fuel and costs of purchased power at least up to the 95th percentile of the expected distribution."[42]

> "In addition to providing estimates of the resulting increase in cost of meeting load under these assumptions, the utilities should provide gas prices and market prices that correspond to the 95th percentile. The utilities should submit a simple comparison of these price series to the base case assumptions. For gas prices, these should include monthly average prices."[43]

2. Utilities And Party Positions

PG&E developed its gas price forecast using gas commodity prices based on the April 19, 2004, closing price of forward contracts traded in the NYMEX plus location basis obtained from broker quotes for gas delivered at AECO, Topock, Malin and PG&E Citygate for the period through February 2009, which marks the end of NYMEX availability. For March 2009 and beyond, PG&E extrapolated gas prices using monthly energy prices and maintaining the same monthly relationship as exhibited in the prior 12 months to March 2009. As required by the June 4 ACR, PG&E states it estimated its 95th percentile portfolio risk using thousands of natural gas and electricity price scenarios in a Monte Carlo simulation.[44]

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[42] D.04-01-050, p. 98.

[43] ACR, p. 16.

[44] PG&E direct, Ex. 34, pp. 4-10.

PG&E includes Table 5-4 in its rebuttal testimony, Exhibit 36, at pp. 7-8 that presents gas prices resulting from their representation of volatility. As exhibited in that table, widths of the probability distributions are substantial and they grow as the delivery period is further into the future, indicating that gas price volatility has been included in the analysis. PG&E noted that Monte Carlo analysis was not driven by a set of fundamental variables; natural gas prices were simulated directly.[45]

SCE's analysis relied on a fundamentals gas price forecast prepared by Global Insight (GI) , an international consulting firm and noted expert in gas forecasting, for all the major pricing points in the Western Electricity Coordinating Council (WECC). This forecast provided SCE with first and second standard deviation gas price forecasts. GI developed its gas price forecast using global and local factors which impact gas prices in the WECC. Specifically, global impacts include the price of oil and importation of liquified natural gas (LNG) into the U.S, while local impacts include the development of LNG facilities and supply basin as well as pipeline development in the Western U.S. The standard deviation forecast was developed using variables such as U.S. economic growth, LNG imports, California economic growth and weather. SCE provided a comparison of GI's forecast and the CEC's. CEC's forecast is higher than GI's and the difference is assumed to be due to the impact of future LNG supplies.[46] SCE acknowledges that forward gas prices have risen since April

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[45] Ex. 36, at p. 7-8.

[46] Edison, Ex. 73, pp. 93-4.

2004, however the magnitude of the gas price forecast is not a major factor for SCE in determining what proportion of resource additions are gas or non-gas fired.

The forecast developed by SDG&E was designed following a five-step process using the Gross Domestic Price inflation index, basin differentials and adding various costs for transportation from the basin to the border. SDG&E provides comparisons with other gas price forecasts and SDG&E asserts that its forecast is in line with them. Variations among the other forecasts are due to assumptions about LNG and outlook about other supply conditions. SDG&E notes that the difference between SDG&E's forecast and the average cash price of gas at Henry Hub is statistically insignificant since it is within one standard deviation of historical monthly prices.[47] SDG&E argues that it is inappropriate to use NYMEX futures as a forecasting tool, since it is a one-day sample of the market.

Monthly prices at the San Juan Basin are not "adjusted", but calculated from historic month-to-annual ratios. In response to criticisms of its gas forecast, SDG&E contends that it is erroneous to state that many charges are added to San Juan Basin prices. It is reasonable to expect LNG supplies to continue to grow and moderate prices in out years. Gas price forecast applies to base case scenario and does not reflect "year-to-year" volatility.

UCS asserts that none of the utilities provided enough information (e.g., description of inputs or relationship to end results) in filings or confidential workpapers to allow UCS and other intervenors to determine exactly what their

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[47] SDG&E, Ex. 14, p. 1.

assumptions were in conducting computer simulations of expected future gas prices.

In general, UCS alleges that the IOUs gas price forecasts were deficient as follows: PG&E did not discuss how it would manage gas price risk associated with gas-fired resources apart from its DWR and QF contracts or whether PG&E designed its portfolio options in order to minimize gas price risk; SCE did not say what its preferred portfolio was and included no discussion on how it would manage gas price risk nor did it provide any alternative portfolios designed to minimize that risk; and SDG&E, intentionally or unintentionally, minimized its gas price risk through 2010 by choosing a portfolio that would not require it to procure conventional resources before then and failed to indicate whether gas price risk will be a consideration in procuring power post 2010.

UCS recommends that the Commission mandate that utilities account for gas price risk when determining how they plan to buy power; provide details of all variables and ranges used in simulations; and results of simulations should be used to create a portfolio least susceptible to future expected gas price risks. In addition, the Commission should require the IOUs to supplement their forecasts using different price scenarios, clearly detail the variables and range of values assigned to each variables used in simulations, and use results to create portfolios that mitigate future gas price risk.

UCAN only addressed SDG&E's gas forecast and urges the Commission to reject it since it reflects prices significantly lower than the current NYMEX prices. UCAN is concerned that low gas price projections may skew long-term resource plans and, if intended to be used as a baseline, then it may have the effect of triggering new procurement decisions and impacting hedging strategies. UCAN recommends that SDG&E use most up-to-date information available and that it update its natural gas price forecast at least monthly using NYMEX data and or broker quotes.

Given current natural gas spot and futures prices, Strategic Energy claims that all utilities forecasts appear too low. Strategic Energy asserts that unrealistic low gas price forecast would depress the wholesale power price forecast and may affect least-cost procurement and skew results of bid comparison between utility-build and third party procurement.

WPTF finds the gas price forecasts too low and fears that they could be used by the utilities to skew results to favor their own or an affiliate's offer. WPTF urges the Commission to require a utility to commit to a gas price forecast if the utility offers a long-term resource based on a specific gas price forecast.

Parties have stated that the utilities used separate approaches toward developing their gas price forecasts, that their forecasts appear low or that they do not exhibit much volatility. Such concerns were the basis for the gas price forecast guidelines we adopted in D.04-01-050 and the June 4, 2004 ACR and, in particular our order that the LTPPs should reflect a range of expected prices. These requirements adequately address the concerns raised by the parties and ensure that the LTPPs are responsive to the uncertainties of predicting long-term gas prices. To ensure that gas price forecasts submitted in future LTPPs remain robust, we will require that the utilities provide updated gas price forecasts using the same criteria set forth in D.04-01-050 and the June 4, 2004 ACR when subsequent long term procurement plans are filed with the Commission.

IV. How the Utilities' Long-Term Plans Reflect Policies, Goals, And Outcomes From Other Umbrella Proceedings and Comport with the Energy Action Plan

A. Umbrella Proceedings

This OIR was designed to be an "umbrella" proceeding to coordinate and incorporate Commission efforts in the CCA, DR, DG, EE, QF, RPS, Transmission Assessment and Transmission Planning proceedings, as well as to address RA requirements. The June 4, 2004 ACR identified LTPP and RA as the "critical path" issues that need to be addressed in this proceeding.

1. Resource Adequacy

The Commission's decision in RA, D.04-10-035, issued October 28, 2004, among other things, established that all LSEs, including the IOUs, must have reserve margins of 15-17% by June 1, 2006. As part of meeting this reserve margin requirement, each LSE must have 90% of its next summer's requirement [May through September] fully resourced by September 30 of the year before. The decision also established a 100% forward commitment obligation for a month-ahead horizon for the entire year. The IOUs are to plan to meet all RA requirements as set forth in D.04-10-035 as they go forward with their LTPPs.

2. CCA

In R.03-10-003, the Commission is implementing certain provision of AB 117[48] which provides local governments with the opportunity to aggregate energy procurement on behalf of the consumers in their communities. The decision in Phase 1 of that proceeding will facilitate utility planning and procurement decisions.

Much of the debate over the LTPPs raised by potential CCAs, municipalities or irrigation districts, centered on how the IOUs should plan prospectively and judiciously for departing load attributable to CCAs in the future, mainly to avoid utility procurement on behalf of CCA customers. Potential CCAs and others naturally want to limit their liability for utility energy

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[48] AB 117 (Chapter 838, September 24, 2002), which added Pub. Util. Code §§ 218.3, 331.1, 366.2, 381.1 and 394.25.

purchases which they would have to assume as part of a "cost responsibility surcharge" (CRS), which is required by Section 366.2(h) of AB 117. The CRS is intended to make remaining bundled ratepayers indifferent to the departure of utility customers who will be served by the CCA. Phase 1 in R.03-10-003 implements this legislative requirement by adopting a methodology for CCA customers to pay their share of the costs of DWR bonds and contracts, utility procurement contracts and other items. Phase 2 in that proceeding will address customer protections and switching protocols, billing and metering issues and reentry and switching fees.

The IOUs, on the other hand, are concerned with their respective obligations to procure sufficient resources for all of their customers and cite the uncertainty surrounding potential departing load, both in terms of timing and number of customers, for their need to provide for these customers until their departure is definite. This issue of timing is an important facet of achieving balance in light of this customer uncertainty.

TURN takes this issue head-on by identifying a trigger point whereby an IOU can proceed with confidence to stop procuring for potential departing load. TURN suggests that the IOU should stop buying power for CCA customers when the CCA provides a binding statement of intent.

We do not determine a precise trigger point when an IOU can stop procuring in this decision. Instead, we encourage cities and counties that intend to procure power as a CCA to work with the IOU to develop an agreement, which allocates procurement risk in subsequent periods. Based on comments from Chula Vista and TURN, we believe it is appropriate that potential CCAs have the opportunity of providing to the Commission and the relevant IOU, a binding notice of intent. The Commission adopts TURN's concept of providing a "default" option for entities seriously considering CCA. We hereby direct the IOUs, along with interested CCAs, to develop such an agreement. The agreement should specify a date at which the IOU's planning responsibility for the CCA load terminates and the CCA will be responsible for this function, so that the CCA's customers will not bear the stranded costs responsibility for utility procurements entered into after the agreed upon date. The agreement should also identify the load that the CCA intends to serve. In the event that the CCA cannot meet this date, the CCA will be liable for any net incremental procurement costs incurred by the utility.

Future IOU procurement plans shall incorporate reasonable anticipated CCA departing load. A prospective CCA provider should inform the utility of its intentions as early in the planning cycle as possible. IOU plans shall acknowledge potential CCA departing load by identifying the CCA, estimated departing load, and the implication for utility procurement liabilities.

a) Potential Stranded Costs Due To Customer Load Uncertainty

A major issue in this proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligations to provide reliable service to their customers. The implementation of CCA, departing municipal load, and the potential for lifting, in some form or another, the current ban on allowing new DA all create a great degree of uncertainty as to the amount of load the existing utilities will be responsible for serving in the future. Given the potential for a significant portion of the utilities' load to take service from a different provider, the utilities are concerned that they could end up over-procuring resources and incurring the stranded costs associated with these resources.

One solution to this problem, discussed above, is the adoption of load forecasts that seek to address, to the extent possible, the uncertainties over the future load that the utilities will be responsible for. Another solution is for the utilities to be entitled to recover any stranded costs occurring as a result of their efforts to meet their load obligations.

The IOUs support the concept of stranded cost recovery for their investments and believe it is a critical factor that needs to be resolved in order for them to plan their future procurement strategies. Consumer groups (TURN, ORA) worry that absent such a safeguard, the utilities' remaining customers would wind up responsible for these costs, violating the ratepayer indifference standard that the Commission has previously adopted. While limiting procurement choices to short-term options might tend to mitigate stranded costs, it could also lead to the rejection of longer-term contracts, especially in the area of renewables, and could result in a non-optimal resource portfolio and higher costs to all consumers.

Needless to say, the parties opposing the imposition of exit fees are either those customers most likely to depart the existing system (CMTA/CLECA, Modesto, SSJID) or ESPs that would serve this departing load. Modesto and Strategic/Energy, however, recognize that some stranded cost recovery might be allowed but only due to "unforeseen circumstances."

The above parties generally advocate that the primary means to minimize or eliminate stranded costs is for the utilities to develop flexible portfolios with significant shorter-term purchases that could be rapidly reduced as load fluctuates.

WPTF also opposes stranded cost recovery, believing the utility should recover the costs of any excess capacity through a capacity market. Constellation makes a similar argument, proposing a "slice of load" approach wherein the utility would sell off a share of its resource commitments to other suppliers and that any new contracts entered into by a utility contain assignability provisions.

In general we agree that the utilities should be allowed to recover their stranded costs from all customers, including an exit fee. Such an approach best meets the Commission's goals of providing "the need for reasonable certainty of rate recovery" (as required under AB 57 and noted in the June 4th ACR) as well as best ensuring that California meets its energy needs.

Requiring departing customers to assume a fair share of their costs is also consistent with the Commission's policy of holding captive ratepayers harmless as required by state law.

As many parties noted, in its last procurement decision (D.04-01-050) the Commission stated that a flexible utility portfolio, consisting of a mix of short-, mid- and long-term resources would be the best mechanism to protect against utility over-procurement. However, since the issuance of that decision, the Commission has now made the utilities responsible for ensuring local reliability, accelerated the resource adequacy requirement from 2008 to 2006, and adopted RPS target goals resulting in the solicitation of new renewable energy sources by the utilities. These initiatives, combined with the existing overhang of utility retained generation and long-term DWR contracts significantly limit the flexibility that the utilities have to quickly adjust their resource portfolios. All of these resource additions benefit all existing customers by improving reliability and promoting renewable energy development.

There is also a potential mismatch between the types of resources that the utilities need to procure (primarily peaking and load following) and the resources that departing customers require (primarily base load with a lesser amount of peaking/load following capability). Thus it may not be possible for the utility to develop a resource portfolio that accurately matches the load profile of expected departing load.

Providing for stranded cost recovery provides a greater incentive for the utilities to enter into five year or longer contracts for existing capacity that many parties (IEP, Duke, Calpine, SCE, PG&E, ISO) are advocating as the optimal approach to ensure the availability of these resources.

Even WPTF, which does not support exit fees, is advocating for the utilities to enter into these longer-term contracts.

There is also the concern that the utilities may need to enter into new contracts (and/or construct) new capacity to ensure that California has sufficient resources toward the latter years of this decade. In order for these resources to be on-line when needed, it may be necessary to begin construction of these projects in the very near term. Almost all parties, including WPTF, agree that new construction would require a minimum ten-year contractual commitment. In the near-term, it appears that the utilities are the only entities capable of facilitating the financing of these projects through long-term contracts.[49]

New renewable projects, necessary for the achievement of the EAP and legislative goals, also require long-term commitments in the range of 10 to 20 years.

For the above reasons, it appears that the utilities may need to make longer-term commitments for capacity and energy that may become stranded at some point during the life of these projects.

49 See, for example, the comments of Calpine, the CAISO, TURN and PG&E.

Therefore, the utilities should be allowed to recover the net costs of these commitments from all customers, including departing customers. This does not mean that the utility should recover the total cost of these commitments, only the uneconomic portion. Similar to the treatment of DWR energy commitments, the utilities must take appropriate steps to minimize their costs by selling excess energy and capacity needs into the marketplace. These other revenue sources (market sales, sales into the ISO's energy/ancillary services market, and potential sales into capacity markets should they develop) should be credited against the utilities' costs. As the utilities will be acquiring their new resource needs through the competitive and transparent procurement process that we are adopting, it is our expectation that there should be little if any stranded costs. However, any longer-term contract implicitly can become stranded based on changes in the market.

At this time, California utilities do not have access to a functioning capacity market. Moreover, such a market should not be the utilities' sole recourse. As Edison and others note[50], there is no guarantee that revenues from a capacity market would be equal to the utilities' costs. Still, development of a liquid and competitive capacity market would reduce the risk of the utilities acquiring assets even as they face the risk of customer departure. It would also facilitate the mitigation of any remaining costs. The resource adequacy workshop process will discuss methods of trading capacity so that LSEs, including the utilities, will have a method for exchanging capacity that otherwise could become stranded. Constellation's "slice-of-load" proposal is also better considered as part of the resource adequacy process. Allowing the utilities to recover stranded costs from all customers who benefited is consistent with recent Commission policy with regards to new resource additions. In its decisions on SDG&E's Reliability RFP (D.04-06-011) and on Edison's Mountainview facility (D.03-12-059) the Commission required that all existing customers of the utility were responsible for any potential stranded costs for a period of ten-years. This decision therefore adopts the same standards for fossil-fueled resources acquired by the utilities either directly or through contract. The utilities should be allowed to recover stranded costs for these resources from departing load over either the life of the contract or 10 years, whichever is less. The ten-year recovery period will also apply to any utility-owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation.

As several parties have noted, limiting commitments for new resources to only ten years may still increase costs for captive ratepayers due to the need for the project developer to seek accelerated cost recovery for their investments rather than amortizing these assets over a longer time period. Because any utility commitment for longer than five years must be approved by the Commission, we will allow the utilities the opportunity to justify in their applications, on a case-by-case basis, the desirability of adopting a cost recovery period of longer than ten years. In reviewing any such requests the Commission will examine the benefits to ratepayers as well as the current state of the utilities' customer base.

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[50] TURN, NRDC.

With regard to the long-term contracts for renewable generation called for by the legislature, we have previously authorized the utilities to enter into contracts with terms of up to twenty years order in order to encourage development of these resources. We will therefore exempt RPS contracts (but not renewable energy contracts that may emerge from all-source solicitations) from the 10-year cost recovery requirement and allow any stranded costs from these contracts to be recovered from all customers including departing load, over the life of the contract. Similar to fossil-fueled resources, the utilities also retain the opportunity to justify a longer cost-recovery period in their applications for those renewable resources selected as a result of an all-source solicitation.

Cost recovery for that portion of a resource acquired by the utilities to meet local reliability needs should be recovered from all customers.

As part of the issue of stranded cost recovery, SCE proposes that we change the direct access switching rules adopted by the Commission. NRDC requests that departing customers provide 10-years notice. Other parties seek further clarification as to how stranded costs would be collected from new DA customers. All of these proposals are premature at this time. They are better discussed if and when the Commission addresses the issue of allowing new direct access to occur,[51] which, under present legislation, cannot be before expiration of the last DWR contracts in 2013.

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[51] For example, the Commission did not address these issues in either Edison's Mountainview facility or SDG&E's RFP proceedings.

3. Demand Response (DR)

DR programs can be used to help achieve both system efficiency and reliability goals. There are two general types of DR programs that the IOUs use to reduce demand when energy prices are high or when supplies are tight: 'price-responsive' programs (in which customers choose how much load reduction they can provide based on either the electricity price or a per-kW or kWh load reduction incentive), and emergency-triggered programs (in which customers agree to reduce their load to some contractually-determined level in exchange for an incentive, usually a commodity discount). Both types of programs motivate customers to reduce their loads in exchange for some type of benefit – such as reduced energy rates, bill credits or exemptions from rotating outages. For purposes of clarification, the term 'demand response program' should be interpreted in this decision to mean 'price-responsive' programs for which the Commission has established specific MW targets to be incorporated into the IOUs' LTPPs.

Price-responsive programs have been the subject of R.02-06-001. D.03-06-032 adopted price-responsive programs, set target goals and directed the utilities on how to integrate DR goals into their procurement plans. As of July 2004, the IOUs have a combined total of **519** MWs[52] enrolled in the authorized programs.[53] D.03-06-032 also adopted DR goals for years 2003 – 2007.

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[52] 290MW for PG&E, 205 MW for SCE and 24 MW for SDG&E, derived from utility demand response/interruptible monthly reports.

[53] The IOUs currently have a combined total of 1,500 MWs of potential interruptible MWs from programs authorized by previous Commission decisions.

The 2005 goal is 3% of 'annual system peak demand', increasing to 4% in 2006 and 5% in 2007. The adopted goals apply only to 'price-responsive' DR programs. MW savings generated by interruptible programs do not count toward the DR goals articulated in the EAP. Enrollment in interruptible programs is capped at 2,500 MW.

D.03-06-032 also directed the IOUs to include the adopted DR MW goals in their procurement plans, along with documentation of the amount of MWs to be achieved by July of each year, the programs and/or tariffs they will rely on to achieve the MW targets and a contingency plan for covering capacity needs should they fall short of meeting the MW goals.

On October 15, 2004, the IOUs submitted DR program proposals in the DR proceeding for the purpose of meeting their 2005 goals. These proposals include modifications to existing DR programs as well as new programs. If their proposals are approved by the Commission, the IOUs anticipate enrollment of the following amounts of demand response MWs by July 2005:

PG&E:	508 MWs[54]
SCE:	442 MWs[55]
SDG&E:	75 MWs[56]

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54 R.02-06-001 Proposal of Pacific Gas and Electric Company (U 39-E) Concerning Working Group 2 Programs and Related Issues, Public Version, October 15, 2004, Appendix C, p. 2.

55 R.02-06-001 Southern California Edison Company's (U338-E) Demand Response Program Proposals for 2005-2008, October 15, 2005, p. 64.

56 R.02-06-001 Filing of San Diego Gas & Electric Company, October 15, 2004, p. 8.

PG&E complies with D.03-06-032 in that its LTPP contains DR MW goals that are derived by applying the appropriate percentages to its forecasted system peak demand for future years (PG&E assumes the 5% is applicable to the years after 2007) for the low, medium and high scenarios. In terms of specific MWs, PG&E assumes 450 MWs of price-responsive DR for year 2005 (medium load scenario). PG&E acknowledges that it does not know if achieving this MW goal, or future years goals, are feasible, implying that its DR component is not an accurate forecast of the future, but rather an attempt to be in regulatory compliance with D.03-06-032.

In contrast to PG&E, SCE's LTPP does not assume the adopted 3% of annual system peak DR will occur but provides a modest forecast of 358 DR MWs for future years. SCE's forecast reflects what it believes is realistically achievable for the programs. This constitutes less than 2% of SCE's annual system peak demand in 2005.

Like SCE, SDG&E's LTPP acknowledges that it will be short of achieving the Commission's DR MW goals. Specifically, SDG&E estimates 27 MWs of DR by 2007. SDG&E's plan reflects what it believes is realistically achievable for these programs.

All three IOUs question the achievability and cost-effectiveness of the DR MW goals, noting that there may be more cost-effective alternatives to meet their loads. The IOUs also note that it is currently unknown as to how many MWs DR programs can actually produce, and that current methods of measuring their effect may need to be revised. In addition, all three IOUs, in particular PG&E, advocate an annual review of the DR goals and adjustments to the goals based on the performance of the DR programs and their cost-effectiveness relative to other procurement options.

Since D.03-06-032 established the parameters of the DR program, the only issue in this procurement proceeding is whether the IOUs are implementing the adopted goals in their LTPPs and how they treat the load savings. ORA observes that PG&E categorizes DR as a supply resource, while SCE and SDG&E consider it a 'load modifier.' SDG&E rebuts ORA's observation, noting that it categorized DR as a supply resource.

In this procurement proceeding, the utilities provide an estimate of the number of MWs that constitute 3% of their annual system peak demand. The following are the MW targets for the year 2005:

PG&E:	450 MW
SCE:	628 MW
SDG&E:	125 MW

It is clear that the utilities have used inconsistent definitions of annual system peak in arriving at their MW targets for price-responsive demand. For each utility, the "annual system peak' should be the annual system peak for their respective service territories, inclusive of all customers taking service within those boundaries. We direct the utilities to verify in their compliance filing, detailed below, that the numbers reported above are consistent with this definition, or provide updated targets that reflect this definition.

It is too early to judge whether or not the current DR goals are achievable. Rather than adjust them now or institute an annual review/adjustment process as suggested by the IOUs, the Commission will retain the current 3% of annual system peak goal and further encourage the IOUs to continue with their best efforts in reaching them. Cost-effectiveness of DR programs is also important to the Commission, and future DR proposals will be evaluated for their cost-effectiveness in the DR rulemaking (R.02-06-001) or its successor.

The Commission recognizes that by keeping DR MW goals at their current levels there may not be, at some point, any program that is cost-effective relative to alternative supply resources. As stated above, we believe it is premature to make that judgment today. Because DR programs are currently voluntary, the challenge of designing cost-effective programs while in pursuit of greater amounts of DR MWs each year may very well prove to be an impossible task. If and when that point becomes evident, the Commission will need to either reduce its DR MW goals or begin consideration of mandatory DR programs and tariffs.

SCE's and SDG&E's LT plans provide DR MWs that they believe are realistically achievable, as opposed to incorporating the Commission's DR MW goals into their plans. PG&E's 2005 program plans would meet the MW goal for 2005, but it is not clear that the 3% figure PG&E calculated is based on its "annual system peak" as defined herein. In fact, the LTPPs for SCE and SDG&E reflect an even lower amount of MWs than the utilities expect to enroll in programs by July 2005. This decision's approval of the IOUs' LT plans is not an affirmation that the utilities are no longer required to pursue the more aggressive DR goals, rather they are expected to continue to explore and find ways to meet those goals until otherwise directed. The Commission will consider whether or not to approve specific proposed programs in
R.02-06-001.

4. Distributed Generation (DG)

In D.04-01-050, the Commission provided direction for the inclusion of DG in this long-term procurement proceeding as follows:

> "The utilities next round of long-term procurement plans should include a more robust discussion of distributed generation to include: (1) a line item entry clearly identifying distributed generation separate and apart from other entries such as energy efficiency and departing load; (2) the energy (GWh) and demand (MW) reduction attributed to distributed generation; and (3) a description of the technologies the utility includes in its definition of distributed generation as well as a statement noting whether its forecast includes utility-side distributed generation, such as QFs."[57]

On March 16, 2004, the Commission opened a new DG rulemaking, R.04-03-017. Among the high-priority tasks of the rulemaking is the development of a cost-benefit analysis methodology applicable to DG technologies. Parties filed opening testimony on October 4, 2004. Reply testimony is expected in early 2005 and evidentiary hearings are scheduled for March 2005.

To date, the Commission's efforts in the area of DG have focused on promoting customer-side DG installations in utility service territories. These efforts are directed in four areas:

i. Financial Incentives – rebates are offered to customers installing DG through the Self-Generation Program & CEC's Emerging Renewables Technology program

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[57] D.04-01-050, p.122.

ii. Interconnection Rules -- streamlining interconnection regulations and processes through the Rule 21 Working Group.

iii. Special Tariffs and Exemptions -- such as the standby charge exemptions for certain DG in accordance with Pub.Util. Code §§ 353.1 and 353.2 and the Departing Load Cost Responsibility Surcharge exemptions from D.03-04-030.

iv. Net Metering – the PUC expanded net metering eligibility to include biogas digester and fuel cell projects along with the currently-eligible solar and wind projects.

In addition to promoting customer-side DG, the Commission is also pursuing grid-side initiatives. In accordance with D.03-02-068, the three IOUs are required to evaluate DG as an alternative to distribution system upgrades, subject to a prescribed set of conditions enumerated in the decision. As of the effective date of this decision, none of the utilities have yet issued RFOs identifying projects where DG might serve as an appropriate alternative.

With respect to the utilities' LTPPs, each IOU prepared a DG forecast that is based on a forecast of DG operating on the customer-side of the meter. These estimates are then deducted from the load forecast. This treatment is consistent with the load forecasting approach recommended in the Workshop Report on Resource Adequacy Issues, dated June 15, 2004, and later adopted in D.04-10-035. The workshop report stated that "Parties agreed that customer-side distributed generation should be deducted from LSE load forecasts."[58] This resource counting protocol recognizes that customer-side DG reduces the utility's actual

[58] Workshop Report on Resource Adequacy Issues, Prepared by ALJ Cooke, June 15, 2004, p.15.

load to be served and the associated reserve margin attributed to that self-served load.

In its LTPP testimony, SCE states that "it is planning on issuing a [RFP], soliciting location-specific demand-side DG to defer distribution upgrades in 2004."[59] SCE indicates in its Opening Brief that this effort has been pushed back to 2005.[60] [61] Interveners did not offer testimony on any DG specific issues raised in the utility resource plans.

We find that the utilities' treatment of DG as a component of the load forecast is appropriate. The utilities shall continue to adhere to the directives for reflecting DG estimates in load forecasting consistent with D.01-04-050 and D.04-10-035. We also encourage SCE to move forward with its planned DG RFO, the results of which will be monitored by the Commission for guidance in both the DG rulemaking and this docket. Lastly, we note that the DG rulemaking's progress towards developing a cost-benefit analysis methodology for DG will inform future policy guidance we provide to the utilities regarding DG as a procurement resource.

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59 Exhibit 73, SCE testimony, p. 85.

60 Edison's opening brief, pp. 29-30.

61 We note current Self-Generation Incentive Program (SGIP) eligibility rules prohibit utility customers "who have entered into contracts for DG services (e.g., DG installed as a distribution upgrade or replacement deferral) and who are receiving payment for those services; (this does not include power purchase agreements, which are allowed) from participating in the SGIP program." [D.01-03-073, Attachment 1, p.25]

5. Energy Efficiency (EE)

The utilities reflected the Commission's preferred loading order by including EE savings targets in their LTPPs as the priority procurement resource. Since the IOUs filed their LTPPs on July 9, 2004, the Commission issued D.04-09-060 on September 23, 2004. D.04-09-060 translated into a numeric goal the mandate from the EAP to reduce energy use per capita. For the electric IOUs the adopted savings goals reflect the expectation that EE efforts in their combined service territories should be able to capture on the order of 70% of the economic potential and 90% of the maximum achievable potential for electric energy savings over the 10-year period covered by the LTPPs. The annual and cumulative goals for energy savings through 2013 are presented in tables to D. 04-09-060.[62] In its post-hearing brief, SCE states that its targets are already higher than the Commission goals established in D.04-09-060, but PG&E's targets in its 10-year plan are lower than those in the said decision. SDG&E, on the other hand, continued to use its EE forecast from its 2003 LTP with the expectation that it will need to update its forecast and resource plans to reflect the goals adopted in D.04-09-060.[63]

PG&E, SCE and SDG&E should meet or exceed the Commission's EE goals over the next ten years and specifically over the next EE funding cycle (2006-

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[62] Tables 1A to 1E of D.04-09-060 show the total electricity and natural gas program savings goals for each IOU service territory and for all IOUs. Attachment 9 to the said decision shows the corresponding funding levels (PGC + procurement funds) implied by the adopted energy savings goals.

[63] NRDC's opening brief presents a comparison of the utilities' LTPPs' proposed electricity savings targets versus those adopted in D.04-09-060.

2008) and to revise and update their plans to be in alignment with these goals. PG&E, SCE and SDG&E are to incorporate the goals from the EE decision in their LTPPs, and as these energy savings goals are updated and amended by subsequent decisions, the IOUs are to incorporate the most recently adopted energy savings goals into their plans. As directed in D. 04-09-060:

> The energy savings goals adopted in this proceeding shall be reflected in the IOUs' resource acquisition and procurement plans so that ratepayers do not procure redundant supply-side resources over the short- or long-term. **To this end, our upcoming decisions in R.04-04-003 concerning the long-term procurement plans and 2005/2006 ongoing procurement authorizations of PG&E, SCE and SDG&E shall be made in full recognition of the aggressive energy savings goals we adopt today.** For the procurement plans that will be filed in 2006 and during subsequent procurement plan cycles, or for any updating to the long-term procurement plans required by the Commission before then, PG&E, SDG&E and SCE shall incorporate the most recently-adopted energy savings goals into those filings. "(D.04-09-060, Ordering Paragraph 6, emphasis added)

SCE proposed to add a 1% reliability factor to downgrade program savings from non-utility EE programs operating in its territory. SCE asserted that this reliability factor would address the uncertainty in the timing and magnitude of savings from non-utility programs until rigorous evaluation, measurement and verification (EM&V) of these programs becomes available.[64] We reject SCE's proposal and reiterate our prior directive in D.04-01-050 for the utilities to count expected energy savings from non-utility programs that operate in their service territories. As we stated in D.04-01-050:

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[64] SCE opening brief, p. 36.

> As more and more non-utility entities enter the energy efficiency program delivery field, more and more energy savings will be attributed to non-utility providers. Therefore, in this proceeding, in the next utility filing of their long- and short-term procurement plans, we order utilities in their demand forecasts for those filings to include expected energy savings from non-utility programs that operate in their service territories. (D.04-01-050, p. 107.)

The utilities noted in their LTPPs that several issues are critical to the achievement of their energy savings targets and success of EE programs. These include EE program administrative structure, program funding cycle and duration, EM&V framework and protocols, performance incentives, fund shifting authority, and avoided costs used in cost effectiveness calculations for EE, demand response, and other applications. The Commission has deferred consideration of most of these issues to the EE rulemaking (R.01-08-028) and not in this proceeding, as discussed in D.04-01-050. The Commission has also instituted R.04-04-025 to address avoided cost issues pertinent to EE programs and other resource applications. We will continue to coordinate these various proceedings to the extent that our decisions in those proceedings impact the utilities' LTPPs.

6. Qualifying Facilities: Long-Term Policy For Expiring QF Contracts

On September 30, 2004, ALJ Wetzell issued a ruling "initiating the Commission's consideration of a long-term policy for expiring QF contracts" (p.1). The ruling called for proposals for such a policy [to] be filed on November 10, 2004, which "may also address policy for new QFs" *Id.* Comments in response to those proposals are due December 8, 2004. The ruling further stated that "the final schedule for adopting a long-term policy for expiring QF contracts [in R.04-04-003] will be determined after review of the comments and a determination of whether evidentiary hearings are required" (p.4). The ruling "anticipated establishing a schedule providing for a Commission decision in the first quarter of 2005 if hearings are not required. If hearings are required, ... a Commission decision [is anticipated] in the second quarter of 2005.

Although we anticipate adopting a long-term policy for expiring QF contracts in this rulemaking, R.04-04-003, by mid-2005, we may be able to benefit from the work being done on avoided cost issues in R.04-04-025, *Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities*. Parties are, however, aware that R.04-04-025 will be litigated during 2005. A PHC in R.04-04-025 was held on November 9, 2004. To the extent that the development of a long-term policy for expiring QF contracts in R.04-04-003 becomes contingent upon any anticipated policy outcomes in R.04-04-025, unacceptable delays in the establishment of such a policy could result. Specifically, QFs whose contracts expire after December 31, 2005 are not eligible for the one-year or five-year contract extension options set forth in D.03-12-062 and D.04-01-050, respectively. Currently, the only recourse for QFs, whose contracts expire in 2006 and beyond, is (1) to participate in any upcoming power solicitations, or (2) negotiate bilateral contracts with utilities. Neither of these two options is entirely certain. Though we expect QFs to continue to participate actively in these opportunities, thus, without contract extensions or a new long-term policy, QF contracts that lapse in 2006 could cause QF power to go off-line at that time. However, our plan to address these issues by mid-2005 will avert these concerns.

7. Renewable Energy Resources

On August 8th, 2003, this Commission, via an Assigned Commissioner's Ruling, established criteria for interim renewable energy solicitations prior to full Renewable Portfolio Standard (RPS) implementation. The ACR acknowledged that "some utilities may wish to execute contracts for renewable generation prior to full development of the criteria and rules for a solicitation under the RPS, based on current market conditions" and directed that the ruling "gives guidance and parameters for utilities wishing to consider renewable purchases in advance of full RPS implementation". Sixteen months after the establishment of these temporary rules the RPS program is now in effect, and we will therefore terminate the interim authority granted by the August 8th, 2003 ACR, on February 8th, 2005. After that date no Advice Letters seeking approval of interim renewable contracts will be accepted; compliance with the procurement goals of the RPS program will be via RPS-specific solicitations, supported by any renewable generation procured through all-source solicitations.

The RPS Program requires each IOU to increase "its total procurement of eligible renewable resources by at least an additional 1% of retail sales per year so that 20% of its retail sales are procured from eligible renewable energy resources no later than December 31, 2017."[65] The EAP and the current RPS implementation proceeding, R.04-04-026, have adopted a policy of accelerating the target date to 2010, and we remain committed to that goal.

As stated above, following the "loading order" contained in the EAP is the first priority for IOU resource procurement, meaning that EE and demand-side

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65 Pub. Util. Code § 399.15(b)(1).

resources should be employed first. When these opportunities are captured, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues an RFO for generation resources, it must be prepared to defend its selection of fossil generation over renewable generation offers. In other words, selection of renewable generation is the rebuttable presumption guiding IOU generation procurement.

However, we are concerned that this loading order policy preference may not be fully realized if the transmission cost methodology employed by the Commission in I.00-11-001 has the effect of putting renewables in "last place." In that proceeding, CEERT has questioned whether renewables are being held to a more rigid standard than conventional generation resources in terms of determining available transmission resources for, and assigning costs to, renewable generation. It is critical that the Commission move quickly to continue the process of refining the transmission cost methodology. As stated below, the IOUs are directed to file fully-developed RPS plans in the RPS proceeding, including detailed information regarding necessary changes to transmission policy in order to achieve the 2010 goal. These plans should be modeled on the detailed renewable generation information provided by SDG&E in this proceeding. The RPS docket is part of the "umbrella" of cases this proceeding is coordinating, and therefore this RPS planning effort will have full access to the record under consideration here. Parties can utilize the filings in this docket in advocating for inclusion of specific issues in those plans.

In general, IOUs are directed to procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and will be allowed to credit this procurement towards their RPS targets. If an IOU succeeds in procuring sufficient renewable resources to meet its 2005 RPS

Annual Procurement Target (APT) via an all-source RFO, it will not be required to undertake an RPS-specific solicitation. This is in keeping with the Legislature's clear intent, in creating the RPS program, that renewable procurement be integrated as closely as possible with general IOU procurement practices. To further this effort, we will be working over the course of the next LTPP cycle to fully imbed the RPS into long-term planning, placing renewable energy development where it belongs - central to the IOUs' resource planning efforts.

Development of the RPS program will continue, however, and the IOUs will be prepared to issue RPS solicitations in 2005. The direction provided in this decision regarding the application of the EAP loading order to IOU all-source solicitations, and the increased emphasis on renewable energy in all-source solicitations, does not in any way indicate a change in Commission policy regarding the importance of the RPS program or our commitment to its continued implementation. The RPS program remains the principal means by which this Commission will achieve its renewable energy goals.

V. Party Comment on Renewables in the Proposed Decision

Party comments on the Proposed Decision suggest the need for greater clarity regarding several aspects of this renewable energy direction[66]. We address these issues below.

"Maximum feasible" procurement of renewable generation*:* A number of parties requested greater specificity regarding this direction. The all-source solicitation should consider renewable resources as follows: in preparing its RFO, the IOU will identify the specific types of electricity products it is seeking, and will employ the least cost-best fit method of bid evaluation. This requires that a renewable bidder be responsive to the IOU's expressed power needs – i.e. meets the "best fit" criteria. In this instance, the IOU will employ the GHG adder discussed below in comparing the bid prices of the renewable and non-renewable options. If the renewable resource is cost-effective when the adder is

[66] Parties commenting on the renewable generation aspects of the Proposed Decision include Strategic Energy / Constellation New Energy, SVMG, City of San Diego, SCE, SDG&E, ORA, Sempra, PG&E, CEERT, NRDC, TURN, CLECA / CMTA, and Calpine.

included (i.e. its bid price is less than or equal to the fossil generator's bid price), the IOU is to select the renewable bid. Thus, the renewable generator must both provide the specific product sought, and be cost-effective when the GHG adder is employed, in order for the "maximum feasible" standard to be in effect.

Role of RPS policies in all-source procurement: A number of parties, particularly PG&E, raised questions in their comments regarding the interaction of all-source renewable procurement with RPS policies around the Market Price Referent (MPR) and Supplemental Energy Payments (SEPs). To be clear, neither of these policy implements are to be employed in the all-source solicitation process. As described in the previous section, renewable bids are to be favored in the all-source solicitation process to the extent that they provide the desired electricity product and are cost-competitive in light of our greenhouse gas policies.

Combination of all-source renewable procurement with ongoing RPS activities: Parties expressed a range of views regarding the implications for the RPS program of the all-source emphasis on renewable generation bids. CEERT and others are deeply concerned that the RPS program not be forsaken with this new emphasis, and that the necessary improvements to the IOUs' RPS plans not be unduly delayed. TURN and UCS share these concerns. On the other hand, Sempra and CLECA/CMTA approve of what they consider the decision's rejection of resource-specific solicitations in the future. To be clear: the all-source solicitations are meant to complement our ongoing work in the RPS program, and to present a second opportunity for renewable resource development to take place. The RPS program remains a top priority for this Commission and the state, and work is ongoing in that docket to address the concerns expressed by CEERT in its comments. The RPS proceeding has full access to the record in this docket, including the filings concerning the present IOU planning for RPS development. These weaknesses will be addressed in the RPS proceeding in 2005, and solutions will be incorporated to the extent feasible into the 2005 RPS solicitations and the next round of IOU long-term plans in 2006.

To further the state's clear goal of promoting environmentally responsible energy generation, we also adopt a policy that reflects and attempts to mitigate the impact of GHG emissions in influencing global climate patterns. As described in this decision, the IOUs are to employ a "GHG adder" when evaluating fossil generation bids. This method, which will be refined in future proceedings, will serve to internalize the significant and under-recognized cost of GHG emissions, help protect customers from the financial risk of future GHG regulation, and will continue California's leadership in addressing this important problem.

As described above, this will have the effect of improving the economic viability of renewable energy resources in all-source IOU RFOs. In time, as this method is refined to incorporate our ongoing efforts in the Avoided Cost proceeding, it may be possible to recast the RPS program as more central to IOU procurement than a set-aside for particular types of resources. We reiterate, however, that we will continue to develop and implement the RPS program as a principal means of increasing the state's renewable generation stock.

a) IOU Positions on Renewable Energy in the LTPPs

PG&E projects that under the load assumptions of its medium load scenario, if it increases its renewables procurement by 1% annually and obtains the assumed wind repowering, it will achieve its 20% RPS target in 2010.[67] On June 30, 2004, the ED approved PG&E's Renewable Energy Procurement Plan, and in accordance with that approval PG&E issued an RFO on July 15, 2004, for renewable resources. PG&E's 2004 annual procurement target is 9,474 GWh per year. To meet the 20% renewable energy target by 2010, PG&E anticipates incremental energy deliveries from newly-contracted resources at an average rate of approximately 700 to 800 GWh per year. PG&E does not identify a preferred resource stack because the utility does not want to thwart market innovations that may occur over the course of the plan and believes the market is the best determiner of what resource is bid.

SCE's long-term plan includes a scenario for achieving the 20% target by 2017 and an accelerated target for achieving the 20% target by 2010. Under both scenarios SCE expects to achieve the 20% target by 2007. SCE's long-term plan does not foreclose procurement that would result in SCE's exceeding the 20% RPS target. SCE states that it will consider renewable resources as part of its all-source solicitation and evaluate all bids, including renewable bids, without regard to whether the 20% target will be exceeded. SCE does not express any preference for a technology type, but instead intends to procure the LCBF renewable resources. SCE fears expressing a preference for technology types would create a bias for future renewable solicitations and could elevate a "preference" as a consideration over LCBF.[68]

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[67] PG&E opening brief, p. 37, citing Ex. 34, PG&E/LaFlash, pp. 5-12.

[68] SCE opening brief, p. 39.

SDG&E's LTPP includes an aggressive renewables resource plan that is designed to meet an overall renewables resource goal of 20% by 2010. SDG&E's aim is to attain a diversified portfolio resulting in a renewable resource mix consisting of Bio-Gas, Bio-Mass, Wind, Geothermal, Solar and Small Hydro technologies. SDG&E developed this portfolio stack and technology mix based upon information obtained from its 2002 renewable RFO process, discussions with potential developers, bilateral negotiations, information from the CEC and the utility's "best estimates" of the types and amounts of resources likely to be available in the future.[69] In order to achieve the target by 2010 with an ideal mix of technologies, SDG&E plans on procuring an additional 2,496 GWh through bilateral contracts and RPS RFP solicitations, including exploring the possibility of utility ownership.

While SDG&E is aggressively working towards achieving the 20% target by 2010, it realistically knows that a number of factors, including the availability of renewable resources, in and out of area, transmission access to sources in other areas, availability of funding, utility ownership, pricing issues, and the ability to procure and trade Renewable Energy Credits (REC)[70] may affect its ability to meet its goal. SDG&E issued its first RPS RFO on July 1, 2004, and does not yet know the final results of that solicitation.

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[69] SDG&E opening brief, p. 53.

[70] Tradable RECs allow the positive environmental attributes associated with renewable energy generation to be sold independently of the underlying electricity. In concept, an entity obligated under the RPS – or some other environmentally-derived procurement restriction – could purchase a tradable REC instead of electricity to satisfy its obligations.

Many intervenors expressed agreement with the approach SDG&E took in identifying a renewable resource stack, estimating costs and benefits of each and identifying potential barriers to access. PG&E and SCE did not include the same level of specificity in their discussion of future RPS procurement and many parties urged the Commission to direct these utilities to supplement their LTPPs. PG&E and SCE retorted that they want to be open for what ever mix of resources presents itself in a RPS RFO and do not want to prejudge what bids will meet the LCBF test.

b) Parties' Positions

The City of San Diego focused on SDG&E's LTPP and especially on the utility's RPS goals to ensure that they comport with the direction the city is headed. Specifically, CSD is concerned that the utility will replace renewable DG with imported renewables, especially if the requested 500 kV transmission line is approved. Instead, CSD would like SDG&E to balance its RPS goals with net-metered generation. While CSD supports the concept of tradable RECs, it argues that the utility should not be able to take DG RECs in an effort to achieve its RPS target. Instead SDG&E should pay for the RECs.[71]

UCS was one of the intervenors that wants PG&E and SCE to supplement their filings and provide more detailed annual analysis of renewable resource <u>potential</u> over the next 10 years. Specifically, the renewable resource analysis should include (1) assumptions for renewables procurement for the next 10 years, (2) development of a resource "stack," identifying the preferred potential

[71] CSD opening brief, pp. 4, 10, 11.

resources, estimated costs and benefits of each, and potential barriers to access and (3) identification of transmission upgrades that the utility believes will be needed in order to access sufficient renewable energy to meet its RPS goals.[72]

UCS also urges the Commission to direct the utilities to file their 2005 RPS procurement plans and on a going-forward basis, to include renewable resources in any and all future resource solicitations, regardless of whether the IOUs have already met their RPS targets. If the Commission adopts debt equivalency (DE) then long-term renewable contracts should have a lower DE (5%) than non-renewable contracts. And finally, UCS wants the transmission constraints on renewable resources that SDG&E discusses addressed in the January 2005 supplement.[73]

Strategic Energy proposes that the Commission not require SDG&E to achieve the 20% RPS target by 2010, unless a REC trading system is established. Strategic is concerned that if SDG&E enters into long-term renewable contracts, and there is no REC trading, there will be stranded costs if load migration occurs.[74]

NRDC seeks clarification that the RPS targets establish a floor, not a cap. The IOUs should not curtail their procurement of renewables once the target is met, but should consider investments in all cost-effective renewable resources

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[72] UCS opening brief, p. 8.

[73] UCS opening brief, pp. 4, 8, 17, 18, 19 and 24.

[74] Strategic opening brief, p. 11.

beyond 20%. Also, transmission planning should involve an integrated comparison of alternative resources.[75]

CEERT agrees with UCS that PG&E's and SCE's renewable procurement plans are inadequate and require immediate revisions. CEERT asks the Commission to direct PG&E and SCE to supplement or amend their LTPPs, no later than January 15, 2005, to include a comprehensive and credible renewable procurement plan consistent with that submitted by SDG&E. CEERT also adopts the same recommendations made by UCS for the renewable resource analysis. In addition, CEERT wants SCE to report on the status of its 2003 interim procurement negotiations.[76]

We agree that the renewable procurement sections in SCE's and PG&E's LTPPs are inadequate and need revision. However, the revisions, with a detailed analysis, will be developed in the IOUs' 2005 RPS procurement plans, which will be filed in R.04-04-026, reflecting the concerns expressed in this Decision and following the guidance to be developed in that docket. All IOUs will provide detailed annual analysis of renewable resource potential over the next 10 years in their 2006 LTPPs. All IOUs will need to include transmission planning for renewable resources in their 2006 LTPPs. Transmission issues will be further addressed in I.00-11-001, in coordination with the RPS docket.

We also find that RPS targets are a floor – not a ceiling. EAP loading order places renewables above conventional generation. "…clear direction was given

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[75] NRDC opening brief, pp. 57-58.

[76] CEERT opening brief, pp. 15 and 26.

to the utilities to consider all cost effective energy efficiency, demand response, and renewable resources prior to considering the addition of conventional supply or transmission resources in meeting future resource needs."[77]

With regards to using unbundled RECs for RPS compliance, this is a complex issue and the record here is insufficient. To make a determination on this policy in this proceeding at this stage is premature. R.04-04-026 will consider this issue as appropriate.

2. Transmission Assessment Process

The April 2003 EAP identified collective agency support for improvements to transmission planning and permitting. It was in this context that the Commission initiated R.04-01-026, issued January 24, 2004, to streamline the transmission planning process for the IOUs by eliminating the duplicative transmission need assessments that currently exist at the CAISO and the Commission. We directed the IOUs through the June 5 ACR and Scoping Memo to take steps toward integration of generation and transmission planning when they made their July 2004 LTPP filings. Various parties identify weaknesses with the IOU filings in this respect. The CAISO asserts that one criterion for judging the LTPPs is whether they were adequate to allow the Commission to accomplish the objectives outlined in R.04-01-026. In this context the CAISO observes that the utilities' LTPPs are insufficient, and that additional information must be obtained from the IOUs in future submissions, in order to allow the Commission and CAISO to accurately assess transmission requirements. The CAISO

[77] D.04-01-050 p. 53.

recommends that the utilities include conceptual scenarios for planned resource additions and assessments of associated transmission requirements. The CAISO adds that integrating the CAISO Transmission Expansion Planning Process (TEP) with the LTPP process should be a key element of this proceeding.

The Commission agrees that the LTPPs do not include sufficient information to enable the CAISO to accurately assess transmission requirements. We agree that integrating the CAISO grid planning processes with the Commission's LTPP process is a worthwhile goal. We further conclude that this integration should include the CEC's IEPR process. The September 16, 2004, ACR in this docket outlines a first order description of how these processes should be coordinated. However, as the ACR states "some subjects, such as transmission planning, are being addressed in more detail in other venues…" One of these other venues is R.04-01-026. In that regard we observe that on October 15, 2004, the Assigned Commissioner in R.04-01-026 issued a ruling stating "[t]o achieve a comprehensive resource planning framework, the Commission must streamline the transmission planning process and integrate that with the biennial procurement process." Finally, since the conclusion of the EH in the LTPP proceeding, the legislature passed and the Governor signed SB 1565, which requires the CEC to prepare a strategic transmission plan as part of its IEPR responsibilities. Clearly there is no shortage of desire for improvements, but actual progress has been slower than many would like.

a) Transmission Planning under I.00-11-001

Investigation (I.) 00-11-001 was issued by the Commission in November 2000 to implement AB 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply. Eight transmission issues have been addressed in eight separate phases of this investigation. Phase 1 identified 30 initial projects designated by the utilities to relieve constraints; Phase 3 evaluated a proposal by SDG&E for a second 230 kV Mission-Miguel transmission line based on economic need and Phase 4 ruled on the application by PG&E for a certificate of public convenience and necessity (CPCN) for the Path 15 upgrade. Three phases of the proceeding are still active:

(1) Phase 5: Generic Economic Methodology for the Evaluation of Transmission Projects

It is generally accepted that transmission projects are undertaken for two reasons: reliability and economics. Reliability standards are issued by the North American Electric Reliability Council (NERC), WECC and the CAISO. These standards are implemented by the utilities with little or no controversy (keep the lights on).

On the other hand, the evaluation of the need for transmission projects not required for reliability, but which could yield economic benefits, and to whom the benefits would apply (a set of ratepayers, consumers as a whole, electricity producers, or a combination of the foregoing) is extremely complex and methods are still being developed. The essential problem is that the benefits depend on future conditions which cannot be accurately predicted: the cost of fuel, interest rates, construction costs, the quantity of hydropower available and the behavior of merchant producers in optimizing their return. The CAISO has been working on a generic methodology for more than three years; the latest effort is called Transmission Economic Assessment Methodology (TEAM), which calculates the benefits of transmission and generation on an integrated basis. However, the Commission staff and others have found that improvements and refinements in the methodology should be pursued.

The development of a generic methodology for evaluating the economic feasibility of transmission infrastructure is still a work in progress.

(2) Phase 6: Transmission needs in the Tehachapi Wind Resource Area

The CEC has identified 4000 MW of potential wind generation in the Tehachapi area in Kern County and an additional 500 MW south of Tehachapi in Los Angeles County. The purpose of Phase 6 is to define and then construct the transmission infrastructure necessary to transmit this power to load centers. In D.04-06-010 the Commission staff, to be assisted by the CAISO as needed, was assigned the task of coordinating a nine-month study "to develop a comprehensive development plan for the phased expansion of transmission capabilities in the Tehachapi area." Each phase will trigger an application by SCE for a CPCN for construction of facilities defined in that phase. Because the lead time for transmission is longer than for generation, the challenge for the planners is to provide incremental transmission such that new generation has access to load as it comes on line, without building transmission that will not be used. A report on the study's findings will be filed by SCE on March 9, 2005.

In addition, SCE is required to file by December 9, 2004 an application for a CPCN for the construction of the first phase of the Tehachapi transmission. On September 1, 2004, SCE filed a report stating that by December 9, 2004 it would file a complete CPCN application for a transmission line to accommodate wind generation in the Los Angeles County area and "…as much of the CPCN application information as it has completed…" for the first phase of the Tehachapi transmission. Staff are reviewing SCE's filings.

PG&E says that it will "examine a number of economically-driven projects…in accordance with Decision 04-06-010" [Tehachapi]. SCE describes the development of transmission for Tehachapi in its Renewable Conceptual

Transmission Plan, dated August 2003. This plan is being currently reviewed and revised in Phase 6 of I.00-11-001.

The intention of Phase 6 is to define and bring about the timely construction of the transmission infrastructure required to connect the Tehachapi and Los Angeles County wind power to load centers, but D.04-06-10 also calls for the study group to address whether the transmission planning approach adopted for the Tehachapi area should also apply in other areas of the state with renewable resources, consistent with the CEC's Plausible Resource Scenarios. A similar collaborative process now is underway in the Imperial Valley region focusing on transmission to accommodate geothermal and other renewable development.

(3) Phase 8: Transmission Costs for Renewable Portfolio Standard Bid

Bids from developers of renewable resources are to be evaluated on the basis of LCBF. A factor in the cost to the utility of the connection to the network of a generation facility is the cost of the transmission upgrades required by the connection. Formulating the methodology for estimating this cost and dividing it among potentially multiple bidders is the subject of Phase 8. In D.04-06-013 a methodology was prescribed for the assignment of transmission costs to the first round of bids beginning on July 1, 2004. Accordingly, the utilities filed Transmission Ranking Cost Reports (TRCRs) for use in the 2004 RPS solicitations and these were adopted by ACR. Only one party, CEERT, filed comments on the TRCRs. CEERT questioned whether renewables are being held to a more rigid standard than conventional generation resources in terms of determining available transmission resources for, and assigning costs to, renewable generation. CEERT also argues that this result is in conflict with the EAP's "loading order" policy preferences and has the effect of putting renewables in "last place."

The Commission intends to move quickly to continue the process of refining the transmission cost methodology.

b) Integrated Generation and Transmission System Planning, Timing, Flexibility

PG&E suggests that an iterative process between resource planning and transmission planning is needed, so both can be planned in an orderly manner. However, it is PG&E's position that until the locations, timing and characteristics of the new resources can be identified and incorporated into the resource mix, it is not possible to definitively identify the transmission needed to accommodate them. PG&E adds that it is not desirable to plan transmission based on speculation that certain resources may develop. PG&E argues that to do so would waste ratepayer money and distract attention from developing transmission projects whose need is more immediate.

SCE believes that transmission and deliverability issues should be considered during the individual RFP solicitations in the economic evaluation of the individual bids.

SDG&E is convinced that its LTPP emphasizes the need for a diverse portfolio of supply- and demand-side options, as well as transmission, in order to balance lowest cost with reduced volatility and risk.

CEERT alleges that only SDG&E presented a credible renewable procurement plan integrating both resource and transmission planning. UCS found that each of the utilities' LTPPs should be supplemented to add specific and detailed information on transmission upgrades. UCS further adds that the CAISO's grid planning process is a complement to, but not a substitute for, the

Commission's oversight of the utilities' procurement responsibilities. NRDC states that the CAISO's transmission economic assessment methodology (the TEAM being examined in Phase 5 of our Transmission Investigation as described elsewhere in this decision) should complement more robust utility LTPPs, but should not substitute for the integrated analysis necessary in the LTPPs.

TURN found that the issue of integration of generation and transmission planning in long-term procurement planning was not explored in any real depth in this proceeding but notes that the Commission is exploring this issue in R.04-01-026 and Phase 5 of I.00-11-001. UCAN found the integrated analysis to be lacking. ORA urges the Commission to insist that the IOUs include consideration of generation alternatives in the "need" determination for proposed transmission lines.

NRDC believes that the IOUs should be directed to thoroughly compare "non-wires" alternatives to transmission projects in an integrated fashion and include more detailed information in future LTPPs about alternatives to the proposed transmission projects that were considered.

The Commission agrees that the issue of integration of generation and transmission planning was not fully explored in this proceeding, despite our direction in D.04-01-050, as discussed below. The Commission also agrees that the utilities' LTPPs did not fully integrate generation and transmission planning. We note that the Commission intends to explore this issue more fully in R.04-01-026.[78] In D.04-01-050, the Commission discussed changes that would be

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[78] It is our desire that the CEC and CAISO collaborate with the Commission in that proceeding. As we work with the CEC and the CAISO to implement the coordination

Footnote continued on next page

needed to move from the current planning process to a more integrated process, and including the following direction:

"The integrated resource planning we seek to achieve would provide a comprehensive context for all of a utility's resource decisions and would include the following features:

1. Rather than considering projected load and resource needs only on a statewide or service territory scale, each utility would assess the different characteristics of the many planning areas within its service area – taking into account the nature of local customer load (such as specific industries, the residential mix, and related load profiles), transmission and distribution constraints, existing generation resources, land use concerns and community values.

2. Each utility would develop a base plan that would take into account least-cost resources, reliability needs, fuel diversity, and other risk management concerns. On the local level, the utility would determine the optimal way to meet demand (whether it would be through energy efficiency, demand reduction, transmission or distribution additions, distributed generation, renewables, or fossil generation).

3. On a service territory-wide basis, the utility would then determine whether the optimal local solution adequately supports total resource needs and the achievement of the state's policy preference for energy efficiency and

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among processes called out in the September 16, 2004, ACR and the mandates of SB 1465, we will require further integration of generation and transmission planning as a planning process.

> renewables, and adjust the plan as needed to serve those broader needs."

In that decision, the Commission recognized that it would take time for the utilities to develop the capability to plan on this level. We note that in most respects, the utilities have not achieved this type of disaggregated planning. Undertaking the steps described above is consistent with, and perhaps critical to an effective integration of generation and transmission planning. SDG&E, in its current plan, has shown signs of moving in this direction. We fully expect SDG&E to continue to improve its planning process along these lines, and for PG&E and Edison to do so as well.

We do not endorse or in any way approve the transmission projects proposed in the utilities' LTPP. Specifically with regard to SDG&E's request, we do acknowledge the lengthy process that is needed to plan, license and construct transmission, so we encourage SDG&E to continue its planning efforts and move forward with evaluating these transmission alternatives for meeting a local resource deficiency by 2010.

c) Enhanced Supply to Load Pockets

Phase 2 of the RA portion of this proceeding will provide a determination on local capacity requirement and deliverability for resource adequacy in the early summer of 2005.[79] Those requirements will inform and govern the utility transmission and procurement requirements going forward. Therefore, it is premature to address specific requirements in this proceeding. However, it is

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[79] See also discussion of temporary local reliability requirements under Section VIII.B. Local Reliability as Part of the Procurement Process

important to clarify how the local capacity and deliverability requirements will come into play in future planning decisions. We expect that the CAISO will work closely with the Commission to establish the local capacity procurement requirements based on deliverability of resources into load pockets and transmission constrained areas of the grid and to work with the CEC to provide guidance for LSE filings in the 2005 IEPR proceeding.

Once the local procurement and deliverability criteria are established and then updated as needed to reflect changes such as new transmission or generation, we expect the criteria to be incorporated into and guide the long-term plans going forward. For example, the a determination is made that "x"% of the supply to meet San Francisco load must come from within the local area given the transmission transfer capability into that area, the long-term plan should incorporate that criterion. In this example, the long-term plans should specify how the utility will meet the "x"% in-city supply criteria, including through approved demand side options, or the transmission upgrades the utility intends to build to increase the transfer capability and decrease the local procurement requirement. We recognize the importance of the CAISO in helping us to establish the criteria so that the Commission can apply them to the utilities' planning practices. The CAISO core expertise in the area of transmission planning and grid operations is critical to inform the Commission's procurement decisions. This approach will assure that the long-term resource procurement meets the CAISO short-term grid requirements. It will also assure that the resources the utilities procure pursuant to their resource adequacy requirements meet the CAISO operational needs.

VI. Implementing the EAP Loading Order

The EAP prioritizes resources in a "loading order" of policy preferences that emphasizes energy conservation, resource efficiency and reducing per capita demand on the demand side of the equation, and favors renewables over fossil-fueled resources on the supply side. The order of resource priorities is: EE and DR, renewables (including renewable DG), clean fossil-fired DG, and clean central-station generation. Sensible transmission investments should be made in concert with these other resource commitments.

Sections of this decision describe the objectives and direction for aggressive procurement of renewable generation resources, contain guidance for procuring clean fossil resources and discuss transmission and DG, respectively. The direction is clear: IOUs should implement the EAP loading order when soliciting resources as a result of this decision.

All three IOUs' LTPPs present resource procurement scenarios that indicate that they intend to follow the EAP loading order as they go forward with procurement solicitations, evaluations and determinations. In particular they all say they will follow all Commission orders and directives from the companion umbrella proceedings in meeting target goals for EE, DR, renewables and DG, and will consider the targets as floors, not ceilings, in terms of evaluating options. The IOUs followed the EAP loading order for each load and resource scenario, and should continue to do so when conducting procurement pursuant to this decision.

A. Energy Efficiency

1. Cost Recovery for IOUs to Meet EE Savings Goals

While each of the utilities' LTPPs reflected EE as the top priority resource, they differed in their requests for funding approval to procure this resource. As NRDC noted in its reply brief, "PG&E specifically requests that the Commission approve funding for its 2006-2008 procurement of energy efficiency. In contrast, SCE's brief did not address how it intends to request funding approval for the efficiency procurement. And SDG&E requests that the Commission authorize it to file an advice letter (AL) to adjust its electric procurement energy efficiency balancing account (EPEEBA) to match the budgets approved in [D.] 04-09-060."[80] NRDC urges the Commission to approve each utility's proposed investments to procure EE programs for 2006 through 2008, noting that the Commission cannot do so in the EE rulemaking (R.01-08-028) because it is not a ratesetting proceeding. PG&E shares similar views, further noting that the EE rulemaking authorizes only expenditures of public goods funds (PGC) funds and is not the appropriate forum for augmenting EE expenditures by the utilities. SDG&E also noted that D.04-09-060 approved much larger budgets to achieve the adopted energy savings targets but did not explicitly discuss what source will fund the incremental budget. SDG&E assumed that the incremental budget could be authorized in this proceeding, just as D.03-12-062 approved the utilities' 2004-2005 procurement EE funding.

In addition, both PG&E and NRDC propose that the Commission approve additional EE funding if savings targets are expected to be met and funds for 2006-2008 are depleted before the end of the three-year period. NRDC supports this proposal based on its analysis showing that more cost-effective energy savings remain in the outer years of the utilities' LTPPs.[81]

We agree with NRDC and others that this proceeding should be the appropriate forum for authorizing increases in procurement rates to fund incremental EE investments over and above the PGC funding levels. However, since approving the utilities' procurement budget for EE in 2004-2005, we have consolidated consideration of both the administration and funding of EE in our

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[80] NRDC reply brief, p. 9.

[81] NRDC opening brief, p. 56.

EE rulemaking proceeding. R.01-08-028, consistent with our decision in D.04-01-050 that:

> "As the Commission will authorize a uniform of energy efficiency, we believe it is necessary that the Commission have in place a unified administrative structure to oversee all energy efficiency programs regardless of the source of funding in the years ahead. For this reason, we are referring the issue of administration of energy efficiency programs authorized in this proceeding."[82]

Accordingly, we directed in D.04-09-060 that the program administrators we ultimately select for EE (which may or may not be the utilities) would submit proposed EE program plans and funding levels to meet the Commission-adopted savings goals every three years, in ratesetting applications, beginning with a PY 2006-PY 2008 program implementation by Assigned Commissioner or ALJ ruling in R.01-08-028.[83] Authorizing the utilities to request incremental funding via procurement rates for PY 2006-2008 in the manner that NRDC, PG&E and SDG&E propose, would prejudge the issues being addressed in R.01-08-028 and result in a bifurcated administrative structure – which we expressly rejected in D.04-01-050. Therefore, we leave to the EE rulemaking all issues related to the funding levels for the next cycle of EE programs, and how the cost associated with programs will be recovered in rates.

We see this as a transitional phenomenon. We want the utilities to develop fully-integrated resource plans, and cost-effective EE programs should be the first-priority resources. In order for EE to be as effective as possible in displacing

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[82] D.04-01-050, p. 106

[83] See D.04-09-060, Ordering Paragraphs, 1,4 and 5.

the need for central station power plants and other generating resources, the EE efforts must be focused in a manner to meet localized, area-specific needs. This requires an understanding of expected patterns of local load growth, the nature of existing and expected distribution and transmission constraints, and the particulars of local load profiles. In order to encourage the implementation of all cost-effective EE programs, they must be considered in the same context with all other relevant investment options.

All of these factors support ultimately folding the consideration of EE options into the integrated plans. However, we must first establish a long-term program administrative structure and the initial generation of programs to be pursued through that structure. Completion of this process lies many month ahead, dictating an artificial separation of EE planning from other resource planning in this planning cycle. We will expect and require that for future planning iterations, the utilities will fully analyze and propose an EE strategy that will optimize our EE goals and support a low-cost, reliable, diversified resource mix.

2. Energy Efficiency Data in Future LTPPs

NRDC proposes that the Commission establish a list of required data on the EE programs that the utilities should provide at a minimum in their LTPPs. UCS concurred with NRDC's suggestion. This list includes:

- Total proposed investments in EE every year over the next decade, broken out into the PGC and procurement component (in real and nominal dollars);
- New annual and cumulative energy savings as a result of the programs every year over the next decade, broken out into the PGC and procurement components (in GWh);

- New annual and cumulative peak savings every year over the next decade, broken out into the PGC and procurement components (both coincident-peak and non-coincident-peak, in MW);
- The total resource cost (TRC) test net benefits of the proposed investments;
- The average levelized cost of the EE resources;
- Comparison of cumulative energy and peak savings to the Commission's targets;
- The projected percent of demand growth reduced by the programs; and
- The per capita electricity consumption for the service territory over the next decade after factoring in the energy savings from the programs.

We agree that providing information about the EE programs in a consistent format in the utilities' future LTPP filings will facilitate the Commission and parties' analysis of the proposals. NRDC's list provides a good starting point; hence, we will direct the utilities to provide the said information to the extent possible.

B. Distributed Generation

The EAP prioritizes DG in the loading order along with renewable resources and enumerates the following policy objectives:

i. Promote clean, small generation resources located at load centers;

ii. Determine whether and how to hold DG customers responsible for costs associated with DWP purchases;

iii. Determine system benefits of DG and related costs;

iv. Develop standards so that renewable DG may participate in the RPS program;

v. Standardize definitions of eligible DG technologies across agencies to better leverage programs and activities that encourage DG;

vi. Collaborate with the Air Resources Board, Cal-EPA and representatives of local air quality districts to achieve better integration of energy and air quality policies and regulations effecting DG; and

vii. Work together to further develop DG policies, target research and development, track the market adoption of DG technologies, identify cumulative energy system impacts and examine issues associated with new technologies and their use.[84]

The IOUs state that they are meeting the EAP policy goals for DG by reflecting customer-side DG in their load forecasts, by participating in the Rule 21 Interconnection Work Group, and by having Commission-approved methodologies in place for evaluating DG as a distribution alternative in system planning. Intervenors did not file testimony specifically relating to DG and the EAP.

The state is currently meeting the goals of the EAP through two ratepayer-funded incentive programs: (1) the PUC's Self Generation Incentive Program; and (2) the CEC's Emerging Renewable Technology program. We also expect that the Governor's solar systems initiative when implemented, will contribute towards achievement of EAP goals by virtue of its focus on promoting and funding DG installations.

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84 EAP, pp. 4 & 8.

We find that the initiatives cited by the utilities in their LTPP (i.e., DG forecasting, the Rule 21 Work Group, including DG in distribution system planning) are consistent with EAP goals for DG. Furthermore, as we noted elsewhere in this decision, we expect that the cost-effectiveness work underway in R.04-03-017 will provide future guidance to the utilities for incorporating DG in resource planning.

VII. Procurement contracting authority: AB 57, upfront standards, cost recovery and ratemaking

A. Contracting Authority

The prior procurement proceeding, R.01-10-024, was the vehicle used by the Commission to put the IOUs back in the procurement business following the end of the deregulation experiment. Beginning in February 2002 and continuing up to the inception of this current procurement docket, the Commission issued the following decisions to direct the IOUs on filling their NOPs:

- D.02-08-071 authorized the utilities to procure for low-case forecast scenario residual net short (RNS) needs between the effective date of the decision and January 1, 2003 (multi-year contracts were allowed).
- D.02-10-062 authorized contract terms for up to five years for transactions entered into under the modified short-term procurement plans addressing 2003 procurement activities.[85]
- D.02-12-074 authorized the utilities to hedge 2004 first quarter residual net short positions with transactions entered into in 2003.[86]

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[85] D. 02-10-062, p. 47.

[86] D. 02-12-074, Ordering Paragraph 5.

- D.03-12-062 authorized the utilities to enter into contracts with terms up to five years to meet 2004 needs with delivery beginning in 2004.
- D.04-01-050 extended the procurement authority to the first three quarters of 2005, limiting the purchase authority to short-term contracts (contracts of one year or less duration).[87]

1. Parties' Positions

Immediately following the issuances of the December 2003 and January 2004 Commission procurement decisions, PG&E requested an extension to its short term procurement plan (STPP) so it could enter into pre-approved transactions with terms up to five years during the term of its STPP, with changes suggested by PG&E in its petitions to modify (PTM) D.03-12-062 and D.04-01-050 and for automatic renewal of procurement plans. Now, faced with the new reserve requirements of 15-17% by June 1, 2006, from the recently issued RA decision, D.04-10-035, PG&E's NOP has increased over the next five years and increased the utility's market risk exposure. The ability to enter into multi-year agreements is necessary to implement PG&E's midterm resource strategy and to allow PG&E to acquire a resource portfolio with a mixture of contract terms to deal with load uncertainty over the next three to five years.[88]

CAISO, SCE, TURN support and ORA does not oppose PG&E's request.

In its opening testimony, SCE proposes to have the AB 57 procurement plan be approved on a rolling five-year term. AB 57 does not say procurement transactions should be limited to five years or less duration, so there is no

[87] D. 04-01-059, p. 91.

[88] PG&E opening brief, p. 46.

prescription against this modification, and PG&E supports it. In addition, SCE proposes to provide an updated capacity and energy position for seven years forward, based on its medium case scenario, beginning with a compliance advice letter submitted within 30 days of approval of its long term plan.[89]

SDG&E states that short-term procurement plans should continue to be affirmed by the Commission as the upfront standards and criteria for short-term procurement pursuant to AB 57.[90]

TURN supports additional authority to enter into contracts of up to five years' duration regardless of the initial delivery date. However, TURN recommends that contracts with duration of five years or longer be submitted to the Commission for pre-approval.

Duke urges the Commission to direct the utilities to undertake interim capacity procurement to meet the needs during the next three to five years; NRDC wants the Commission to require that the expected carbon emission costs should be used in procurement bid evaluation process; and Strategic argues the IOUs should be making shorter-term commitments, e.g. five years or less.

2. Discussion

It is reasonable to extend the IOUs' procurement authority on a rolling 10-year basis, given that the long-term procurement plans cover a ten-year period and they will be updated and reviewed every two years. We will diligently oversee how the utilities are using this authority. Therefore we

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89 SCE opening brief, p. 67.

90 SDG&E opening brief, p. 74.

authorize the utilities to enter into short-term, mid-term, and long-term contracts, with contract delivery start dates through 2014, provided that the IOUs submit the necessary compliance filings. Contracts with duration five years or longer be submitted with an application to the Commission for preapproval. We should note that the approval process of renewable contracts will differ depending on whether the contract is procured via an all-source or RPS solicitation. As determined in D.04-07-029,[91] renewable contracts from an RPS solicitation will be submitted to the Commission for approval with advice letters.[92] However, renewable contracts from all-source solicitations must be submitted with an application.

B. Cost Recovery for Utility Ownership and Turnkey Projects

1. Parties' Positions

PG&E proposes a ratemaking mechanism for cost recovery that includes the following features: upfront assurance of cost recovery; no opportunity for after-the-fact reasonableness review of project costs if the terms of the upfront approval are met; and a mechanism to allow cost recovery to begin as soon as the facility is operational. In addition, PG&E argues that the Commission's preapproval process should constitute upfront approval of the acquisition costs. That is, if the costs are determined to be reasonable in the preapproval process, and PG&E meets the preapproved upfront conditions, no after-the-fact reasonableness review should be necessary.

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91 D.04-07-029, pp.9-11.

92 We reserve the right to issue a resolution that orders the IOUs to file an application.

SDG&E wants the Commission to provide reasonable assurance of timely and complete recovery of the costs of approved, newly acquired turnkey utility-owned generation assets. SDG&E suggests that the existing Energy Resource Recovery Account (ERRA) provides reasonable assurance that the cost of future procurement contracts acquired will be fully recovered through ERRA mechanism, but the utility is not certain that ERRA provides assurance for cost recovery for new turnkey generation assets.

In D.04-06-011 we approved two turnkey generation projects for SDG&E: Ramco and Palomar. SDG&E, however, is concerned that the Commission did not establish specific revenue requirements for these projects, nor has the Commission specified the framework under which the turnkey costs will be recovered. In the interim, SDG&E believes that ERRA mechanism as established in D.02-10-062, provides SDG&E with reasonable assurance that costs for future procurement contracts will be recovered. SDG&E requests that the Commission provide equivalent assurance for cost recovery of turnkey projects as it has for other procurement resources.

In the LTPP proceeding SDG&E proposes a three-phase cost recovery framework for turnkey project cost recovery that starts with the filing for Commission approval of the project. In that filing, SDG&E will identify the rate-base and operations and maintenance (O&M) -related revenue requirements associated with the project for the first full calendar year of operation of the generation plant. SDG&E proposes to record costs associate with the turnkey plants to its Non-Fuel Generation Balancing Account (NGBA) and ERRA for recovery through SDG&E commodity rates. Under SDG&E's proposal, the Commission will adopt the annual revenue requirement of the applicable turnkey plant simultaneously with approval of the project. Prior to the operation of the turnkey generation unit, SDG&E will file an advice letter to incorporate any adjustments to the adopted revenue requirement.

The second phase of the framework covers the period from the end of the initial phase until the implementation of SDG&E's next Cost of Service (COS) decision to allow for annual attrition adjustments to the authorized revenue requirement.

In the third phase, SDG&E's revenue will be trued up to reflect the costs of these projects.

PG&E requests that the Commission provide timely cost recovery of utility owned generation when the facility starts serving utility customers, whether PG&E operates the plant itself or when it contracts with a third party to operate it. Under PG&E's proposal, PG&E would include the initial capital cost of the acquisition in its request for approval of the contract.

UCAN opposes SDG&E's proposal for cost recovery and argues that the Commission sets revenue requirements in the General Rate Case (GRC) and should not allocate separate revenue requirements for each asset owned by the utility in a non-GRC proceeding.

2. Discussion

We find SDG&E's mechanism reasonable and adopt it for all three IOUs. In the next few years, IOUs could add extensive new generation to their resource portfolios in order to meet their future resource needs. We believe a rate making mechanism needs to be in place to ensure proper and timely cost recovery for these facilities. Two issues need to be decided; the timing and the scope of the cost recovery. First, we determine the appropriate timing of the rate recovery. Both SDG&E and PG&E propose to start cost recovery when the new facility starts operation to serve utility customers. We agree and adopt this proposal.

Second, we adopt SDG&E's proposal for cost recovery. SDG&E proposes to establish rate-base and O&M-related revenue requirements associated with the generation plant and to use its NGBA and ERRA to record costs associated with the turnkey plants and for recovery through SDG&E commodity rates. PG&E proposes differently. In addition to the costs listed above, PG&E proposes that in some cases it may be necessary to request recovery for "financial burden associated with acquisition of utility-owned generation."[93] In PG&E's opinion, these costs may include planning and administrative costs of preparing for the construction or acquisition of the generation facilities, financing costs as incurred, and costs if the project is ultimately abandoned. We believe that some of these costs or risks will be considered in our review and evaluation of IOU contracts for turnkey projects and some will be considered as part of establishing the revenue requirement for these facilities. For example, we expect contracts for turn key projects to address provisions and penalties for project abandonment. As such these types of costs should not receive special recovery treatment. We reject PG&E's proposal in this respect.

C. ERRA Trigger Mechanism

The ERRA trigger mechanism requires the Commission to adjust procurement rates if the ERRA balancing account becomes undercollected or overcollected by more than 5% of the previous year's non-DWR generation revenues. The trigger mechanism is set to expire on January 1, 2006.

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[93] PG&E's prepared Testimony, pp. 2-38.

AB 57 added the following to the Public Utilities Code § 454.5 (d)(3):

> Ensure timely recovery of prospective procurement costs incurred pursuant to an approved procurement plan. The commission shall establish rates based on forecasts of procurement costs adopted by the commission, actual procurement costs incurred, or combination thereof, as determined by the commission. The commission shall establish power procurement balancing accounts to track the differences between recorded revenues and costs incurred pursuant to an approved procurement plan. The commission shall review the power procurement balancing accounts, not less than semiannually, and shall adjust rates or order refunds, as necessary, to promptly amortize a balancing account, according to a schedule determined by the commission. Until January 1, 2006, the commission shall ensure that any overcollection or undercollection in the power procurement balancing account does not exceed 5 percent of the electrical corporation's actual recorded generation revenues for the prior calendar year excluding revenues collected for the Department of Water Resources. The commission shall determine the schedule for amortizing the overcollection or undercollection in the balancing account to ensure that the 5 percent threshold is not exceeded. **After January 1, 2006, this adjustment shall occur when deemed appropriate by the commission consistent with the objectives of this section.** (Emphasis added)

PG&E requests that the trigger mechanism remain in effect for the term of the long-term contracts be approved. DENA strongly supports PG&E's request on the grounds that the extension of the trigger mechanism will provide the certainty needed to maintain or improve PG&E's credit rating and will benefit

PG&E customers, by ensuring that any decreases in procurement costs are passed on to the customers.[94] IEP joins in support with DENA.

We find that the ERRA trigger provides the IOUs assurance that procurement costs will be recovered in a timely fashion, and we keep the trigger in effect during the term of the long-term contracts, or ten years, whichever is longer.

D. ERRA Disallowance Cap

In D.02-12-074, the Commission adopted a disallowance cap applicable to utility administration and dispatch of allocated DWR contracts. The cap amount is equal to two times the utility's costs of procurement function.[95] In D.03-06-067 the Commission ruled the following: SCE's request to expand the disallowance cap established in D.02-12-074 to include all procurement activities violates the legislative mandate of AB 57, as codified in Pub. Util. Code § 454.5, as well as §§ 451 and 702.[96]

The current disallowance cap is applicable to contract administration and dispatch from the integrated DWR-IOU portfolio. PG&E requests that the disallowance cap apply to all utility dispatch, including utility –owned generation, PPAs, and allocated DWR contracts on the ground that this would provide certainty in estimating the potential financial risk utilities face.

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[94] DENA opening brief, p. 13.

[95] D. 02-12-074, Ordering Paragraph 25.

[96] *Id.*, Conclusion of Law 1.

On July 8, 2004, the Commission issued D.04-07-028 which requires utilities to consider local reliability effects in their dispatch decisions. Potentially, this could impact the least-cost dispatch process that is an up-front standard that is included in procurement plans. PG&E argues that given the current concern in the investment community over the utilities' financial health, the Commission should clarify that the cap applies to all utility least-cost dispatch activities undertaken pursuant to the long-term plans approved by the Commission as that will provide needed regulatory assurance.

DWR does not oppose the development of a separate disallowance cap, but does oppose extending the disallowance cap to all IOU procurement activities, especially direct liabilities to DWR.

Consistent with our determination in D.03-06-067, as discussed above, that an extension of the disallowance cap violates legislative intent and the statutes, we reject PG&E's request.

E. Upfront Standards for Utility Procurement Products and Transactions

In previous decisions, The Commission authorized the following products and transaction processes:

	Authorized by D.02-10-062 and/or D.03-12-062
Transactions	(authorized by D.02-10-062) Ancillary Services Capacity (demand side) Capacity (purchase or sale) Electricity Transmission Products Financial call (or put) option Financial swap Forward Energy (demand side) Forward Energy (purchase or sale) Forward Spot (Day-Ahead & Hour-ahead) purchase, sale, or exchange Gas Purchases (monthly, multi-month, annual block) Gas Storage Gas Transportation Transaction Insurance (Counterparty credit insurance, cross commodity hedges) On-site energy or capacity (self-generation on customer side of the meter) Peak for off-peak exchange Physical call (or put) option Real-time (purchase or sale) Seasonal exchange Tolling Agreement

	Authorized by D.02-10-062 and/or D.03-12-062
Additional Transactions	*(authorized by D.03-12-062)* Counterparty Sleeves Emissions Credits futures or forwards Forecast Insurance FTR Locational Swaps Gas Purchases (daily) Non-FTR Locational Swaps Structured Transactions Weather triggered options
Transactional Processes	*(authorized by D.02-10-062)* Competitive Solicitations (Requests for Offers) Direct bilateral contracting with counterparties for short-term products (i.e., less than 90 days) Inter-Utility Exchanges ISO markets: Imbalance Energy, Hour Ahead, and Day Ahead (when operational) Transparent exchanges, such as Bloomberg and Intercontinental Exchange Utility ownership of generation (interim rules set in D.04-01-50)
Additional Transactional Processes	*(authorized by D.03-12-062)* Open Access Same-Time Information Systems (OASIS) Negotiated bilateral contracting allowed for Short-term transactions of less than 90 days duration and with delivery beginning less than 90 days forward. Longer-term non-standard products provided that the IOU include a product justification in quarterly compliance filings Standard products in cases where there are 5 or fewer counterparties (for gas storage and pipeline capacity, only Transparent exchanges to include voice and on-line brokers

In its PTM D.03-12-062, filed February 20, 2004, PG&E asks the Commission to clarify that for purposes of upfront standards for procurement transactions, "short term" means up to and including three calendar months, or one quarter, not "90 days." PG&E also wants a clarification that the IOUs can conduct competitive solicitations in an auction format. PG&E argues that the use of online auction techniques for competitive procurement falls within the guidelines presented in D.03-12-062 and D.04-01-050.

In response to PG&E's PTM, ORA agreed with the short-term definition, but opposed electronic auction authority since the proposal lacks details.

We clarify that D.03-12-062 authorized IOUs to conduct procurement using negotiated bilateral agreements for transactions of up to three calendar months, or one quarter, forward; and that utilities will consult with their PRGs for transactions with delivery periods of greater than three calendar months, or one quarter. We further clarify that D.03-12-062 authorized IOUs to conduct procurement using an electronic auction format for execution of competitive solicitations, among other transactional methods. The authorized products are good for short-, medium-, and long-term procurement.

F. SCE'S AB 57 Plan

SCE states that its proposed revision to its Existing AB 57 Procurement Plan[97] is a component of its long-term procurement plan. SCE further clarifies

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97 The "Existing AB 57 PP is the same as the "2004 Short-Term Procurement Plan – Confidential Version," dated May 15, 2003, as modified by the Commission in D.03-12-062 and submitted by SCE in Compliance Advice Letter 1770-E-A, dated February 23, 2004. These plans are also referred to at times in SCE's LTPP as the "Implementation Plan."

that it does not have a separate AB 57 long-term procurement plan and AB 57 short-term procurement plan. Instead, SCE has one AB 57 procurement plan which is a component of SCE's LTPP showing in this proceeding (SCE LTPP, July 9, 2004, Vol.2, p. 1). SCE states that the objective for each IOU's AB 57 procurement plan is to set the limits (i.e., the upfront achievable standards and criteria called for in AB 57), within which the IOU's transaction activity would be deemed reasonable. All transactions and actions that fall within the boundaries of an AB 57 procurement plan are compliant with the approved procurement plan and accordingly are assured cost recovery. Statute requires that a procurement plan contain upfront achievable standards and criteria.

On February 19, 2004, SCE filed a PTM D.03-12-062 (the 2004 Short Term Procurement Plan Decision). SCE's PTM presented arguments on twelve separate issues in the D.03-12-062 that, SCE contends, affect its ability to procure power and make it difficult for SCE to comply with portions of the decision as it is written. SCE's list of twelve requested modifications are set forth in its LTPP, Vol.2, pp.13-16, which we will not reiterate here. SCE, like PG&E, raised the 90-day vs. one-quarter issue.

We grant ten of SCE's twelve requested modifications with the exception of modifications seven and nine, as shown here:

1. "Modify language that would require an "unqualified certification" as a basis for authorizing SCE's proprietary risk model. The language of the decision must be modified because a certification of this level would be extremely difficult to obtain."
2. "Eliminate the requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges. Allowing transactions from brokers only when the same transaction can be made with an exchange at an equivalent price is impractical."

With regard to an "unqualified certification" of SCE's proprietary risk model, we are not asking that the model be proven infallible. We are simply seeking an independent review of the internal validity of the model, that all the features of the model work as advertised, that the model is mathematically sound and that the assumptions utilized by the model are reasonable.

With regard to the requirement that SCE demonstrate that identified OTC brokers provide prices equivalent to those of exchanges, this is a reasonable upfront standard, consistent with AB 57. The use of transparent exchanges is one reasonable check on the competitiveness of a portion of SCE's procurement activity. We direct SCE to consult with its PRG regarding the specific implementation options that are available.

VIII. Policy Issues Related To Long-Term Plans

The 2000-2001 energy crisis can undoubtedly be considered the antithesis of an open, transparent and competitive bidding process. Fortunately, the California utilities are moving forward in a new hybrid market structure supported in large part by this Commission. Since the crisis, the Commission has authorized, and the utilities have conducted, a number of all-source and renewable power solicitations, which have successfully procured thousands of megawatts of power under short- and long-term contracts to serve California customers. However, not all parties agree on how the solicitations should be conducted. Although all parties tend to agree that the solicitations should take place by way of an open, transparent and competitive bidding process, not all parties agree on the specific definitions, details and logistics of such a competitive process. We want the IOUs to have a mixed portfolio of demand

and supply side resources, and a combination of renewables and fossil- fuel sources, as well as different ownership types.

We have determined that it is time to allow greater head-to-head competition and hereby lift the affiliate ban on long-term power products. Accordingly, we adopt certain guidelines and safeguards, including an independent third party evaluator requirement. We will allow the consideration of debt equivalence in the bid evaluation process as specified herein, and we will also require the use of a GHG adder as a bid evaluation component. With these policies we continue to shape and define the hybrid power market in California so as to advance the positive benefits of competition, and deliver California's energy services according to the priorities of state policy.

A. Proposals Regarding Open And Transparent Competitive Bidding Process

All parties addressing the topic of a competitive bidding process favor an open and transparent process. However, as PG&E and SCE contend, for many parties, especially those in competition with the IOUs, that means that the parties should have more access to confidential utility information. For others, open and transparent means a fair bidding and bid evaluation process.

Calpine states that a lack of head-to-head competition and PG&E's 50/50 proposal are not features of an open, transparent, and competitive bidding process and will not ensure procurement of LCBF resources. In particular, Calpine is concerned that since IOU-owned resources generate earnings for the utility, there is an inherent incentive for IOUs to favor IOU-owned resources over third party PPAs, a fact that was recognized in Decision 04-01-050.[98] Calpine further adds that there is a "fundamental difference in the allocation of risk and the certainty of bid prices between IOU-owned projects and PPAs allows IOUs to unfairly advantage IOU-owned projects vis-à-vis PPAs in the bid evaluation process."[99] Since an IOU can shift the risk of cost overruns and other problems related to the development, construction and operation of a project to ratepayers means that the IOUs' bid strategies are not constrained by normal bid considerations, such as being responsible for the economic consequences of submitting a low bid that is ultimately selected in the solicitation process. Calpine asserts that the only solution to this inequity is to require the IOU to 'commit' to the cost and operating performance estimates it uses in its bid evaluation of the IOU-owned project.

CMTA/CLECA share similar concerns about utility-owned generation contending that (1) "utility-owned generation constructed without the benefit of a competitive solicitation has been too costly" [and that] the Commission has long experience with cost overruns associated with utility-owned generation, citing Diablo Canyon, SONGSs, and Helms Pumped Storage [in particular;]" and (2) that "a competitive bidding process also obviate[s] the need for after the fact reasonableness reviews." Lastly, CMTA/CLECA observe that SCE refuses to sign "contracts for terms longer than three years until the debt equivalence issue

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98 D.04-01-050, *mimeo.*, at 61

99 Calpine opening brief, p. 12.

is resolved," yet the SCE recently received approval for "a 30-year power purchase agreement with its affiliate-to-be … the Mountainview project"[100]

[100] *Id.*, pp. 11, 12.

In addition, CMTA/CLECA claim that the participation of an IOU affiliate can greatly detract from an open, transparent, and competitive bidding process. As a solution, CMTA/CLECA recommend the use of aan independent third party evaluator, as set forth in The FERC's competitive solicitation guidelines[101] which provide specific guidance on transparency, power product definition, evaluation, and oversight.

PG&E and Edison both object to parties having more access to confidential information, which is what some parties believe "open and transparent" means.

With regard to competition, SCE is opposed to head-to-head competition between PPAs and utility-owned generation. SCE contends that "there are important differences between utility-built and independent generation, which are extremely difficult to quantify and evaluate in the same process. The primary differences include the value of operational control, operational and financial risk, special local area needs, flexibility in case of changed circumstances, and the terminal and refinancing value associated with utility plant."[102]

SDG&E is understandably amenable to an open, transparent, and competitive bidding process that includes direct as it recently concluded an all-source grid reliability RFP that netted six new resources that included demand and supply side sources and different ownership schemes. However, tThe utility argues that "[g]iven the wide range of possible offers, however, the Commission

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[101] FERC *Opinion and Order Affirming Initial Decision In Part, Denying Requests for Rehearing and Announcing New Guidelines for Evaluating Section 203 Affiliate Transactions, Opinion No. 473, Ameren Energy Generating Co., et al.* 108 FERC ¶ 61,081 (2004).

[102] SCE opening brief, pp. 88, 90.

should not attempt to predetermine specific methodologies for all future solicitations in this regard. Instead, the Commission should reinforce the objective that a utility seeking approval of a new resource should provide a robust comparison of options that maintains a level playing field for all bidders. The PRG can also play an important role here in advising the utility on its competitive solicitation activities, which is yet another reason that the PRG process should be extended."[103] Sempra supports all-source solicitations and states that "the Commission should require that proposed utility-owned generation projects be competitively bid against other market solutions."[104]

WPTF recommends that long-term procurement efforts by the utilities must include the following mandatory competitive bidding requirements:

- Evaluation of bids should include all incremental costs delivered to load;
- Any procurement process in which the utilities can submit their own bids must be unbiased;
- RFPs should be mandatory for utility procurement;
- Barriers to transmission development that supports markets and fuel diversity should be removed; and
- Winning bids should be binding and non-recourse.[105]

Strategic Energy supports open and transparent competitive bidding for any new medium- and long-term resource needs. Strategic urges the

[103] SDG&E opening brief, pp. 96-97.

[104] Sempra opening brief, pp. 3-4.

[105] WPTF opening brief, pp. 11-13.

Commission to reject PG&E's [50/50] proposal. There is simply no guarantee that set-asides would result in least-cost procurement for bundled customers. Generally, lower costs result from the consideration of the greatest number of procurement options.[106]

1. Discussion and Determinations

Our most recent experience with procurement solicitations was the SDG&E Grid Reliability RFP process that involved head-to-head competition among both supply-side and demand-side resources (megawatts and negawatts), peaking and baseload resources, an affiliate resource, renewable generators, a merchant PPA and utility turnkey power plants. This was our first experience with such diversified head-to-head competition among competing resource types, yet it was a successful undertaking.

In Governor Schwarzenegger's October 8, 2004 energy plan letter published in the San Diego Union-Tribune,[107] the Governor spoke about SDG&E's RFP and said:

> "…it is the ability of utilities to engage in long-term contracts that attracts investors and gets power plants built. In [June 2004], the PUC approved [the SDG&E Grid Reliability RFP results in D.04-06-011,] a plan designed to meet San Diego's energy needs through this decade. The plan includes building two large power plants that will generate 1,085 megawatts of power. (One megawatt powers roughly 1,000 homes). Two more facilities planned for San Diego, one of which is a renewable biomass

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[106] *See* Ex. 70 (Fulmer), p. 20, line 20, to p. 21, line 5.

[107] As referenced by IEP in its Opening Brief, October 18, 2004, p. 2, footnote 2.

facility, will bring an additional 85 megawatts." (Governor Schwarzenegger, Energy Plan Letter, October 8, 2004)

2. Requirements for All-Source Solicitations

- All-source open solicitations need to be transparent and competitive, and in addition, need to be open to all resources (conventional/renewable - turnkeys, buyouts, and PPAs).
- All-source and RPS solicitations need to employ the solicitation bidding guidelines outlined in Section VII.D (pg. 125).
- Following the "loading order" contained in the EAP is the first priority for IOU resource procurement, meaning that cost-effective EE and demand-side resources should be employed first. When these opportunities are captured, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues an RFO for generation resources, it must justify its selection of fossil generation.
- IOUs are directed to procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and will be allowed to credit this procurement towards their RPS targets in 2005 and beyond. If an IOU succeeds in procuring sufficient renewable resources to meet its 2005 RPS APT via an all-source RFO, it will not be required to undertake an RPS-specific solicitation next year.
- The IOUs will employ the LCBF methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative[108] attributes associated with each bid.
- GHG adders are to be used when evaluating fossil and renewable bids in all-source open RFOs.

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[108] Qualitative and quantitative attributes such as performance risk, credit risk, price diversity (10 vs. 20 yr. price terms), and operational flexibility etc.

- DE will be considered when evaluating individual PPA bids, regardless of whether the bids are from a fossil, renewable, or an existing QF resource. IOUs are not to consider resource-specific debt equivalency risk factors in their COC proceedings but should instead use the methodology outlined in this decision.
- IOUs will not be allowed to recover initial capital costs in excess of their final bid price for utility-owned resources, but any cost savings will be shared 50/50 between ratepayers and shareholders.
- The IOUs will be required to use an IE in resource solicitations where there are affiliates, IOU-built, or IOU-turnkey bidders.

B. Affiliate Transactions

D.04-01-050 continued the ban on affiliate transactions, however, our position on this issue warrants re-examination at this time.

> "We do not have the same level of oversight and authority over affiliate transactions that we do over direct utility operations. We recognize that cross-subsidies and anti-competitive conduct has occurred in the past in affiliate procurement transactions and that it could occur in the future under the market structure we adopt here"[1]

As noted earlier in this decision, Sempra argues for the Commission to rescind the ban on affiliate transactions since it prevents utility access to ready built facilities owned by an affiliate. As we have already found in the Mountainview proceeding, A.03-07-032, D.03-12-059, and in the SDG&E RFP

[1] D. 04-01-050, Conclusion of Law 19.

proceeding, A.03-10-007, D. 04-06-011, affiliates can present attractive procurement options.

Calpine, DENA, IEP, and WPTF do not oppose affiliate participation in resource solicitations, provided that certain safeguards are in place like a requirement for third party evaluators. D.04-01-050 noted that ORA had recommended that the affiliate ban not extend to long-term transactions:

> "ORA states that the Commission should continue the ban on affiliate transactions for short-term procurement because the short-term market moves too fast and there is too great of a potential for abusive self-dealing, with little or no possibility for Commission oversight of these types of transactions. However, for long-term transactions, such as long-term PPAs or a turn-key agreement or take-over of a power plant, the Commission should evaluate these transactions under the current affiliate rules. ORA testifies this process should have enough built-in protections to prevent potential self-dealing and other abuses." (D.04-01-050, p.69-70)

Given our desire to consider all competitive options, instead of continuing the ban, and carving out exceptions for unique resources from time to time, we now find that it is in the best interest of the ratepayers and consumers to allow for a full vetting of all available resources in a RFP. We will institute appropriate safeguards for the solicitations for long-term transactions, in part through continuation of utility PRGs and through the use of IEs. Such safeguards can protect consumers from any anti-competitive conduct between utilities and their affiliates. Therefore, by this decision we lift the ban on long-term affiliate transactions for transactions entered into through an open and transparent solicitation process. However, we maintain the ban on short-term transactions because the short-term market moves too fast and there is too great of a potential for abusive self-dealing, with little or no possibility for Commission oversight of these types of transactions**.**

We also reaffirm that the utilities, and in particular their respective risk management committees, maintain complete procurement planning independence from their affiliates. In D.04-01-050, we found that such procurement planning independence was severely lacking for SDG&E.[109] Finally, we reaffirm our prior commitments to revisit our affiliate transactions rules in our open docket on that subject or a successor proceeding, to ensure that proper rules are in place based on the policy we adopt here.

C. Procedures, Rules And Protocols, Including Independent Third-Party Evaluators

The use of IEs in resource solicitations has not been previously required by the Commission. Parties disagree on the role, scope, and need for an IE. Some parties contend that the role of an IE is currently being fulfilled through the PRG. The IOUs are opposed to the delegation of any final decision-making authority to an IE.

As noted by WPTF, FERC has recently set forth Guidelines for Reviewing Future Section 203 Affiliate Transactions, which include guidelines for IEs in 108 FERC 61,081 (July 29, 2004). FERC explained that to the extent to which a utility demonstrates that its RFP process follows the stated guidelines, its application processing time (including litigation) will likely be reduced, thus increasing the possibility of more timely Commission approval through an adequate showing under the *Edgar* standard.[110] In short, guidelines will allow FERC to

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[109] D.04-01-050, pp. 72-74.

[110] FERC Edgar Standard: "We note that there are three ways to demonstrate lack of affiliate abuse under the *Edgar* standard: (1) evidence of direct head-to-head competition between the affiliate and competing unaffiliated suppliers in a formal

Footnote continued on next page

more easily identify transactions that are consistent with the public interest, and, therefore, expedite their approval.[111]

The FERC guidelines provide for substantial IE involvement in resource solicitations at the "design, administration, and evaluation stages of the competitive solicitation process." FERC has set forth "minimum standards for assuring independence and the scope of the third party's role." These IE guidelines are shown here:

> "A minimum criterion for independence is that the third party has no financial interest in any of the potential bidders, including the affiliate, or in the outcome of the process.[112] Preferably, the independence criterion would be the same as that of an ISO or RTO.[113] In this context, "independence" means that the third party's decision-making process is independent of the affiliate and all

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solicitation or informal negotiation process; (2) evidence of the prices which non-affiliated buyers were willing to pay for similar services from the affiliate; and (3) and benchmark evidence that shows the prices, terms and conditions of sales made by non-affiliated sellers. Because the market for generating assets is not nearly as liquid as the market for PPAs, a competitive solicitation through a formal RFP in future section 203 cases is likely to be the most effective way to show that an affiliate transaction is not marred by affiliate abuse. In the context of an acquisition of affiliated generation, a competitive solicitation is the most direct and reliable way to ensure no affiliate preference." 108 FERC 61,081 (July 29, 2004), paragraph 67.

[111] This is similar to our use of the Appendix A "screens" adopted in the Merger Policy Statement to quickly identify transactions that are unlikely to harm competition. Largely due to these screens, this Commission has succeeded in reducing the amount of time necessary to analyze and approve section 203 applications.

[112] *See, e.g.*, Technical Conference Comments of Maine Public Utilities Commission Chairman Welch, Conference on Solicitation Processes for Electric Utilities, Docket No. PL04-6-000, (June 10, 2004) (PL04-6 Conference) at Tr. 78.

[113] *See, e.g.*, Technical Conference Comments of John Hilke, Federal Trade Commission, PL04-6 Conference at Tr. 4.

bidders.[114] Without such independence, the third party could be biased towards the affiliate in order to enhance its financial position. Obviously, a similar concern could arise regarding an actual or potential financial interest link between the third party and any potential bidder. Independence can also be satisfied if the state commission has approved the selection of a third party on the basis of established independence criteria. In addition, the third party should not own or operate facilities that participate in the market affected by the RFP."

"The independent third party should be able to make a determination that RFP process is transparent and fair, and that the RFP issuer's decision is not influenced by any affiliate relationships. For example, if the RFP issuer wishes to use a collaborative RFP design process, the independent third party should be the clearinghouse for comments by potential bidders on a draft RFP and should evaluate those comments as possible revisions to the RFP. The independent third party's role as the sole link for transmitting information between potential bidders and the RFP issuer would also help to ensure that the RFP design will not favor any particular bidder, particularly an affiliate. The independent third party should continue to be a conduit of information between utility and bidders in determining which of the original bid responses are qualified bids or may be included in a short list."

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[114] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs., Regulations Preambles July 1996 – December 2000¶ 31,089 at 31,061 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12, 088 (2000), FERC Stats. & Regs., Regulations Preambles July 1996 – December 2000 ¶ 31,092 (2000), *affirmed sub nom*. Public Utility District No. 1 of Snohomish County, Washington, *et al.* v FERC, 272 F. 3d 607 (D.C. Cir. 2001).

> "At the evaluation stage of the RFP process, the third party should be able to credibly assess all bids based on both price and nonprice factors. It should be able to consider both generation asset bids and power purchase agreements. Also, it should be able to independently verify transmission characteristics that may limit the suitability of certain alternatives. The third party should have access to the same information that the RFP issuer uses in its evaluation and should be able to independently verify its correctness. The third party should also be able to evaluate nonprice traits of various alternatives." [115]

The Commission's only recent experience with an IE was in the SDG&E Grid Reliability RFP process. SDG&E retained "an independent third party, Dr. Boothe, to observe the bid evaluation and selection process to ensure that Palomar[116] was not given special treatment".[117] Dr. Boothe's primary purpose was to ensure that "all competitors were treated fairly."[118] Neither the Commission, nor the IE found that any unfair advantage was conferred to the affiliate bidder. The Commission did not formally evaluate the role of the IE in this RFP process.

Relative to the SDG&E Grid Reliability RFP process, Calpine recommends that an IE play a more significant and active role in any resource solicitation

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[115] 108 FERC 61,081, p.27-29.

[116] "SDG&E is proposing to purchase [Palomar] from SER [Sempra] a 500 MW (base load)/ 555 MW (peaking load) combined cycle natural gas-fired generation plant to be built by SER, and then turned over to SDG&E as a utility owned generation asset. This project is located in the utility's service territory on a 20-acre site in Escondido, and is expected to go on line in June 2006." (D.04-06-011, p. 47.)

[117] D.04-06-011, p.48.

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

involving an IOU affiliate, IOU-built or IOU-turnkey bids. Calpine envisions that "an IE would be responsible for both independently evaluating the fairness of the IOUs' evaluation process and conducting its own evaluation of which resources are the least cost/best fit for ratepayers." Calpine contends that this is "something the current PRGs do not do." In instances where the IE disagrees with an IOU's resource decisions, the IE would provide the Commission with an independent recommendation as to the least cost/best fit resources from the solicitation."[119]

In the present case, "the IOUs believe that the Commission should not require the participation of an IE in resource solicitations that may involve an IOU-owned project (whether IOU-built or turnkey) or where an IOU affiliate participates in the process. Specifically, the IOUs believe the current PRGs provide sufficient independent review of IOU procurement decisions and that there is no reason to change the current structure".[120]

According to WPTF:

> "a structure must be established that puts procurement via contract on an equal footing with utility-build options [and the PRG] process does not rise to the level of an independent evaluator." WPTF further contends that a "level playing field … will result in the least-cost option for ratepayers [which] can be addressed by the Commission adopting clear criteria for evaluation of bids and mandating the use of a third party independent evaluator when a utility-build project or a utility affiliate is a participant in the RFP".[121]

No party recommends the use of an IE in all resource solicitations. Certain non-IOU parties (Calpine, IEP, and WPTF) only recommend the use of an IE in

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[119] Calpine Reply Brief, p.18.

[120] Calpine Reply Brief, p.18.

[121] Opening Brief, p.17-18.

resource solicitations involving an IOU affiliate, IOU-built, or IOU-turnkey, while the remaining non-IOU parties do not offer specific positions on this issue. In contrast, the IOUs state that the Commission should not require the use of IEs in any resource solicitations, and that IEs cannot, and should not, be delegated any authority to make binding decisions on behalf of the utilities.

SDG&E, for example, supports the IE process in concept but contends that the PRG already performs this function. However, SDG&E observes that there might be situations in which a third party IE would serve a "useful purpose"[122] but that the "utility should be left to exercise its discretion to incorporate such a feature as needed into its bid evaluation process."

SCE noted that an IE procurement feature was not adopted in D.04-01-050. PG&E also opposes an IE requirement, citing the same language in D.04-01-050. In that decision, we stated that the PRG served as one safeguard in the PPA vs. utility-owned procurement process. However, we did not preclude the adoption of additional safeguards, as necessary: "Based on our continuing review of the RFP process, we will adopt additional safeguards if we find it is necessary."[123]

We acknowledge the detailed IE guidelines set forth by FERC in its recent July 2004 and generally endorse them. At this time, we will outline an interim approach, which we may refine at a later date based on our further experience in this area. We determine here that we will not allow the IEs to make binding decisions on behalf of the utilities. We will require the use of an IE in resource

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[122] SDG&E opening brief, pp. 102.to104.

[123] SCE opening brief, p. 64.

solicitations where there are affiliates, IOU-built, or IOU-turnkey bidders. However, we will not require that the IEs administer the entire RFO process. The IOU shall consult with its IE and PRG on the design, administration, and evaluation aspects of the RFO to ensure that the overall scope is not unnecessarily broad or otherwise too narrow. IEs should be available to testify as an expert witness in any associated Commission proceeding regarding upfront review of potential solicitation transactions.

IEs should come equipped with technical expertise germane to evaluating resource solicitation power products. IEs should not be general observers hoping to be educated on the job. In the case of an affiliate/IOU-turn key power plant, IEs should be able to quickly scrutinize, examine and essentially break down bids to determine whether the various cost components are reasonable as presented. IEs should be skilled in analyzing a range of power market derivatives (e.g., futures, contracts, options, swaps). IEs should be familiar with the various standard contracts and industry practices. IEs should have experience analyzing the relative merits of various types of PPAs. IEs should be able to evaluate PPAs, turn-keys and IOU-builds on a side-by-side basis. An IE should make periodic presentations regarding their findings to the IOU and to the PRG.

The IOUs may contract directly with IEs, in consultation with their respective PRGs. The IOUs shall allow periodic oversight by the Commission's ED. Alternatively, ED can contract with IEs directly, but we will not require this given that this may result in unacceptable delays in the procurement process. IEs shall coordinate to a reasonable degree with assigned ED and staff as a check on the process.

With regard to consultants that assume the role of an IE, they shall abide by clear conflict of interest standards. We note that FERC has provided guidance on this issue. We would like to require that consultants abide by the appropriate Fair Political Practices Commission guidelines, in order to avoid the types of conflict of interest problems encountered by consultants working on behalf of the State of California and DWR during the 2000-2001 energy crisis. We must ensure the integrity of the IE process to provide firm assurances to the power market. We are open to comment from parties on specific conflict of interest standards.

D. Comparing PPAs to Utility Ownership

1. Parties' Positions

PG&E proposes to conduct two parallel solicitations, one to obtain long term PPAs and another to obtain "turnkey" utility generation. For this round of solicitations PG&E will not accept bids from utility affiliates or subsidiaries. PG&E opines that by conducting separate solicitations for PPAs and utility-owned generation, the impact of DE becomes irrelevant to the choice between 3rd party and IOU-owned generation, except as between competing PPAs.[124]

SCE agrees with the concept of a hybrid market structure provided through both a competitive market and utility-owned generators as established in D.04-01-050, but also argues that the same decision rejects the concept of evaluating IOU-owned and PPA resources in the same RFO. Utility-owned projects, with significantly different benefits, should not be compared against contracts in an RFP. An RFO is appropriate for non-utility owned generation

[124] PG&E opening briefs, pp. 60,61,64,65

resources and a CPCN application is the established procedure for comparison of utility-owned projects with alternatives.[125]

SDG&E is of the opinion that it is neither necessary nor desirable to adopt a mechanism for comparing PPAs to utility ownership. While there are techniques for structuring an evaluation process that puts these differing options on a common basis, it is a very complex process. SDG&E opines that it is preferable to conduct this analysis on an RFP-specific basis to ensure that each project's unique circumstances and attributes are captured. SDG&E argues that the Commission should not attempt to predetermine specific bid evaluation methodologies for future solicitations

While TURN supports the Commissions preference for a hybrid wholesale electric market consisting of PPAs and IOU owned resources, TURN contends that the Commission should not focus on comparing the value of PPAs to IOU-owned projects. Instead, TURN urges that the Commission to adopt the principle that the IOUs will acquire the resources that provide the lowest net cost to ratepayers, regardless of ownership form[126].

ORA's concerns over head-to-head competition between PPAs and utility owned resources center around balancing Commission and legislative policy for favoring certain resources and a hybrid market against the costs of different proposals when making comparisons of competing choices.

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[125] SCE opening brief, pp. 89, 90, 91, 92, 96.

[126] TURN opening brief, pp. 12

Calpine, as a potential bidder of non-utility owned PPA projects favors a transparent competitive solicitation to ensure that IOU-owned resources are not chosen by the utility over 3rd party PPA. Calpine is concerned that because IOU-owned resources generate earnings for the utility, there is an inherent incentive for IOUs to favor IOU-owned resources over 3rd party PPAs. In addition, because traditional cost-of-service ratemaking allows IOUs to pass the cost overruns associated with an IOU-owned resource onto the ratepayers, IOUs can favor IOU-owned resources in the bid evaluation process by submitting low bid prices with the expectation that they will be able to recover cost over runs. Lastly, Calpine argues that the fundamental difference in the allocation of risk and the certainty of bid prices between IOU-owned projects and PPAs allows IOUs to unfairly advantage IOU-owned projects vis-à-vis PPAs in the bid evaluation. To correct the unlevel playing field, Calpine proposes that the IOUs should not be allowed to recover costs in excess of its final bid price. [127]

While the Commission has stated a preference for a hybrid wholesale electric market consisting of PPAs and IOU owned resources[128], this should not undermine the Commission's goal of having the IOUs acquire supply-side resources based on LCBF principles, regardless of ownership form. We agree with Calpine that PPAs and utility-owned resources need to participate in the same all-source open solicitations to ensure LCBF, not in separate PPA and utility-owned specific solicitations as proposed by PG&E.

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[127] Calpine opening brief, pp. 10-12.

[128] See Hybrid Market section in this decision.

We are not persuaded by SCE's argument that D.04-01-050 precludes the IOUs from doing an all-source open RFO because a bid evaluation methodology doesn't exist. The IOUs will employ the LCBF methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative attributes associated with each bid. The IOUs will also need to add GHG adders, as discussed in this decision, to all fossil bids. In addition, when seeking Commission approval for the proposed contracts the IOUs will need to demonstrate that they employed LCBF principles. It is expected that the Commission will revisit the LCBF methodology, integrating "lessons learned" from future all-source open RFOs.

Regarding capping cost overruns associated with utility-owned resources, we agree with Calpine that, "Putting shareholders – not ratepayers – at risk for cost overruns will put IOU-owned projects and PPAs on equal footing (at least with respect to the allocation of risk), impose some measure of market discipline on IOUs when formulating their bids, and better ensure that the resource solicitation process is fair and competitive[129]." Consequently, IOUs will not be allowed to recover initial capital costs in excess of its final bid price for utility-owned resources. See solicitation bidding guidelines outlined below.

<u>All-Source and RPS Solicitation Bidding Guidelines</u>

- 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 (i.e., IOU-built, turnkeys,

[129] Calpine opening brief, pp. 12

buyouts, and PPAs do not need to participate in every all-source and RPS solicitation).

  - Negotiated bilaterals are discouraged – they will be evaluated on a case-by-case basis.[130]

- Bids should reflect total cost (generation and transmission) of delivery to load.

- Bids from Utility-owned generation (IOU-build, turnkey, and buyouts) will be capped at initial capital costs.

  - If actual costs come in under the capped bid, then there should be a 50/50 sharing of savings between ratepayers and utilities.

  - Utility-owned resources that are selected in a solicitation will be eligible for Cost-of-Service ratemaking (future plant additions, annual O&M expenses etc.).

- Utility-built resources that are selected in a solicitation will file a CPCN with the Commission.

  - Solicitation - CPCN process: CPCN process incorporates need determination, cost caps, and CEQA review. Having said that, bid cap would come from the RFO process, need determination would come from the approval of the Long-Term Procurement Plan. The only issue left to be addressed in the CPCN is the CEQA review.

- If an IOU considers the bids from a particular solicitation too high they have the right to terminate the solicitation. However, the IOU will need to reissue another solicitation if they want to file a CPCN with the Commission. They will not be allowed to file a CPCN for a project unless it was selected in a solicitation.

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[130] The procurement mechanism (solicitation, bilateral etc.) for repowered renewables will be determined in R.04-04-026.

E. Debt Equivalence (DE)

Debt equivalence, the term used by credit rating agencies, specifically Standard & Poor (S&P) and to a lesser extent Moody's, to describe the fixed financial obligations resulting from long-term purchased power agreements, allegedly has significant effects on utilities' credit quality and costs of borrowing. As Edison's financial witness testified, "in determining a utility's credit rating, rating agencies pay particular attention to the company's cash flow, including its sources and uses of funds. Of particular concern are obligations that place a call on available cash, reducing a company's ability to make ongoing interest payments or to repay principal."[131] The credit agencies are concerned that PPA payments are fixed cash commitments that, in times of financial stress, may negatively affect bondholders.

SDG&E, SCE and PG&E recommend that DE be adopted in procurement to ensure the resource acquisition process going forward takes into account the impact of DE on the rate of return. As SDG&E argues "[I]t is essentially undisputed that the credit analysts treat the utilities' long-term non-debt obligations, such as PPAs, as if they are in fact debt when they assess a utility's debt capacity."[132] PG&E proposes that the impact of DE on the utilities' financial condition should be addressed in the COC proceeding, but that in this proceeding the Commission should establish that the DE impacts of new long-term commitments may be considered in the contract selection and approval process. This will allow for full disclosure of the financial effects of contracts on

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[131] SCE/Simpson Ex. 73, 21:2-5.

the utilities and promote equal consideration of competing procurement choices.[133] All three IOUs reject the idea of resource specific DE - all resources should have the same DE risk factor.

As forceful as the utilities were in their support for DE, many intervenors were just as strong in their opposition. The record from the four weeks of EH is replete with testimony and cross-examination on the subject of debt equivalency. In fact, except for the subject of QFs, no other subject received as much hearing time as DE.

UCS, for example, argued against using DE when evaluating renewable PPAs, and if the Commission does decide to adopt DE then they should use a lower risk factor for renewable PPAs. UCS fears that if DE is used for renewable PPAs that the beneficial hedging attributes of renewables will not be properly evaluated, and the utilities may not reach their RPS targets. CCC and CAC do not want DE applied to existing QF contracts because of the beneficial properties associated with existing QFs. IEP, Calpine and WPTF all argue against considering DE in procurement since it is a subjective factor, one that could change over time based on an improving regulatory climate, and there is no guarantee that by considering it the credit ratings of the utilities will improve.

Lastly, while ORA urges that DE be only considered in the COC proceeding, TURN supports the use of DE in procurement - assuming it is

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[132] SDG&E opening brief, p. 89.

[133] PG&E opening brief, p. 51.

adopted in the COC. Others just asked that the issue be resolved one way or the other now so it does not stand in the way of reliability and resource adequacy.

We acknowledge that DE is a subjective factor based on the credit rating agencies' perceived risk associated with PPAs. The credit rating agencies' views on such risk are not static and can change with respect to a particular PPA during the term of the PPA. In addition, the imputed DE costs for existing PPAs will be reduced as the regulatory climate in California improves. However, as imprecise and subjective as it maybe, DE is a real cost that needs to be considered when evaluating bids from a PPA vs. a utility-owned resource. As SDG&E states, "[I]t is essentially undisputed that the credit analysts treat the utilities' long-term non-debt obligations, such as PPAs, as if they are in fact debt when they assess a utility's debt capacity."[134] Consequently, the IOUs should take into account the impact of DE when evaluating individual bids in an all-source and RPS RFO, regardless of whether it is a fossil, renewable, or an existing QF resource.

Regarding DE imputation methodology, all three IOUs used the S&P methodology[135] as the starting point for their proposed DE calculations because it is the most developed and transparent approach to calculating DE. We agree with the IOUs and adopt the same methodology for calculating DE, but with some modifications. Specifically, we believe that the 30% S&P risk factor is too high to be reasonable and fair to all PPAs. We find it logical to make some

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[134] SDG&E opening brief, p. 89.

[135] PG&E Opening Brief pg. 51, SCE Opening Brief pg. 86-88, and SDG&E Opening Brief, pg. 93-96

acknowledgement that DE is a factor in utility creditworthiness, but not to the degree shown in the S&P methodology. We believe the regulatory climate (a significant factor in S&P's qualitative 30% factor methodology) is improving in California. We also do not want to create an unfair burden on or a disadvantage for independent power sources over utility-owned, especially in the case of renewable resources.

Therefore, the IOUs will use a modified S&P methodology that employs a 20% risk factor for all PPAs, rather than S&P's 30% risk factor. While several parties endorse resource-specific DE risk factors (i.e., lower DE for renewables), we reject this approach because, as SCE and SDG&E have noted[136], the rating agencies are indifferent to resource type when calculating the DE impact of a PPA.

While we are not saying that there are no other costs or risks that apply when evaluating a PPA vs. a utility-owned resource, this DE methodology should be used by the utilities and/or the IE when evaluating bids in an all-source and RPS RFO. The IOUs will also need to demonstrate, on a total portfolio basis, the DE impact of the PPAs in the Cost of Capital proceeding. As the rating agencies' views on DE change or as we gain more experience with DE evaluation in the COC proceedings, we may adjust the DE methodology used in future. Inasmuch as DE captures any increased financial risk to the IOUs, we may also—in future COC proceedings—want to consider factors that decrease their risks or are of benefit to the utilities when determining their rate of return.

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[136] SCE Opening Brief p. 88, , and SDG&E Opening Brief, pp. 95-96

F. Climate Change Issues in the Long-Term Procurement Plans

1. Background

At the time of the issuance of this decision it is still not known if climate change regulation in the form of GHG emissions limits will be instituted. However, it is likely that GHG emissions will be regulated within the timeframe addressed in the utilities' LTPPs and the lifetime of the utilities' long-term resource commitments. Therefore, it is appropriate for us to consider policies that would limit the exposure of IOU ratepayers to risks associated with this future regulation. California, and in particular this Commission, along with the CEC and CPA, has given clear signals of its intent to be the pacesetters in this arena and take positive steps in seeing action on this front. Beginning in May 2003 with the issuance of the EAP, the state and this Commission committed to making inroads in addressing climate change with the following:

> "The state needs to guide development of the energy system in the public's best long-term interest, to anticipate potential problems, and to make timely decisions to resolve problems. Specifically, the agencies commit to:
>
> 1. Make continuing progress in meeting the state's environmental goals and standards, including minimizing the energy sector's impact on climate change."

Following on the heels of the EAP, the Commission noted in D.04-01-050 that we were:

> "Presently working with a contractor in R.01-08-028 for the explicit purpose of reviewing and updating its avoided-cost methodology for analyzing the costs and benefits of various resource options….In this decision, we refer the question of potential financial risks associated with carbon dioxide

> emissions to R.01-10-028, to be considered in the context of updates to the avoided costs methodology – as part of the overall question of valuing the environmental benefits and risks associated with utility current or future investments in generation plants that pose future financial regulatory risk of this type to customers." [137]

R.04-04-025 is the successor rulemaking to R.01-08-028 for purposes of addressing environmental issues in the context of generation investments.

The Commission then issued this proceeding, R.04-04-003, with Appendix "B" that set forth the "SkyTrust" type Cap-and-Trade Incentive Framework as follows:

> "In terms of specific pollutants, of significant concern to regulators and the public today is the environmental damage caused by carbon dioxide (CO_2) emissions—an inescapable byproduct of fossil fuel burning and by far the major contributor to greenhouse gases. Unlike other significant pollutants from power production, CO_2 is currently an unpriced externality in the energy market…. CO_2 is not consistently regulated at either the Federal or State levels and is not embedded in energy prices…. California needs a framework for procurement incentives that recognizes the importance of reducing California's dependence on fossil fuels—for a variety of environmental, security, and price volatility reasons." [138]

On June 29, 2004, ALJ Wetzell issued a ruling in this proceeding, R.04-04-003, presenting questions for the IOUs to answer and address in their LTPPs regarding climate change:

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[137] D.04-01-059, p. 108.

[138] R.04-04-003, Appendix B, p. 5.

"San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company shall address the following questions pertaining to climate change in their long-term plan filings:

1. Describe the utility's position regarding the extent of the threat posed by climate change, and the contribution of electricity generation to that threat.
2. Describe any internal planning or measurement activities currently being undertaken to evaluate and address the threat of climate change, both generally and as a result of utility operations, including URG and power purchased under contract.

3. Describe, to the fullest extent possible, the utility's emissions profile with respect to the six criteria greenhouse gases: carbon dioxide (CO2); methane (CH4); nitrous oxide (N2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); and sulfur hexafluoride (SF6). Include both URG and power purchased under contract.
4. Describe any steps the utility has taken to minimize the release of these gases as a result of utility operations, and how your Procurement Plan advances this effort.
5. Describe the utility's position regarding the optimal policy response to the threat of climate change, and how your Procurement Plan is aligned with this policy response."
   i. In their LTPPs the IOUs offered a range of responses to these questions, from more concerned with climate (PG&E) to less so (SCE). None provide the profile requested, as they are all moving through the Climate Action Registry's inventory and auditing process now.

In its post-hearing brief PG&E indicated that it plans to value carbon risk with "reputable" price data[139] – and proposes using $8/ton, consistent with the data in the now final E3 Report on Avoided Cost.[140]

NRDC proposes that the Commission direct the IOUs to financially impute a dollars-per-ton CO2 value into the analysis of all fossil bids and in their next LTPPs; require the IOUs to include in their next LTPPs the emissions profiles compiled by CA Climate Action Registry; and instruct the IOUs to "develop and implement a comprehensive GHG reduction plan" via their next LTPPs. We find

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[139] RT 9/7/04, p. 906: 17-20, Pulling.

[140] Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs, E3 Research Report Submitted to the CPUC Energy Division, October 25, 2004. http://www.ethree.com.

these suggestions consistent with the EAP and other Commission statements. UCS urges the Commission to require the IOUs to model carbon costs in future LTPP preparation; to consider these costs, but not price them, in present resource solicitations; and to utilize PG&E's experience from this proceeding in educating parties and the IOUs for future LTPPs. TURN advocates the adoption of a carbon adder taken from the analysis in AC Rulemaking, R.04-04-025; the development of a policy to have bidders submit prices that include and exclude carbon regulation risk and a requirement that market sentiment on carbon prices be divulged.

2. Party Comments on GHG Issues in the Proposed Decision

Climate change issues elicited a substantial amount of controversy in party comments to the proposed decision[141]. UCS, ORA, NRDC, and TURN all support the PD's approach, while PG&E, which is employing such an approach in its internal planning efforts, is silent in its comments. Other parties commenting on the issue were critical, typically arguing that the time is not right for action to address climate change, or that the Commission should collaborate with other regulatory and legislative bodies to enact GHG regulation at a higher level.

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141 Parties commenting on climate issues in the Proposed Decision include CAC/EPUC, CLECA/CMTA, IEP, NRDC, ORA, SCE, SDG&E, SEMPRA, SVMG, TURN, UCS and WPTF.

We find that taking action now is supported by our record, consistent with state policy and compatible with both existing law and ongoing Commission and state programs. The process of employing bid adders does not result in the Commission establishing wholesale rates for power, as SCE contends; bid prices for wholesale electricity do not change in any way. Winning bidders receive the price they offer in a competitive, all-source solicitation. Instead the adders, which are established with reference to a range of market signals and regulatory actions that reveal the future financial risks associated with greenhouse gas emissions, will aid in the selection of those energy resources that are clearly preferred by the state of California. This Commission is acting in the best interest of California ratepayers in taking this action now, and we look forward to collaborating closely with all stakeholders in the further development of our climate change mitigation strategies. We also intend to work with other policymakers and stakeholders in the future to ensure that we can implement on a competitively-neutral basis going forward.

Moreover, the adoption of a GHG adder policy now does not preclude, and in fact is fully compatible with, the adoption of other climate change mitigation policies in the future – including a possible GHG content requirement, or “cap”, and the possibility of a GHG trading system. Adoption of an adder policy now is likely to support - not limit - the development of such policies in the future, should our evaluation of the SkyTrust proposal and similar options (discussed below) indicate that such policies are desirable.

3. Range of values for the GHG Adder

IOUs are directed to employ a GHG adder when evaluating fossil and renewable bids received via an all-source RFO. Utilizing data from the record in this proceeding, following is a range of values for this adder:

a.	Final E3 Avoided Cost Report	-	**\$8/ton C02 today** **\$12.50 by 2008** **\$17.50 by 2013**
b.	PG&E internal RFO review	-	**\$8**
c.	PacifiCorp 2003 IRP	-	**\$8**
d.	NRDC opening brief	-	**\$12 beginning 2008**
e.	Idaho Power Co IRP	-	**\$12.30 beginning 2008**
f.	EIA analysis of proposed legislation[142]	-	**\$15-\$25 in 2010** **\$14-\$36 in 2020**

Consistent with established Commission policy and the positions of several parties, including PG&E, we adopt a range of values to explicitly account for the financial risk associated with GHG emissions of \$ 8 to \$25 per ton of CO_2, to be used in the evaluation of fossil generation bids. This range is taken from information in the present record, and is consistent with actions undertaken by other electric utilities across the country. Each IOU will select a value within the adopted range and respond to party comment on the value, before employing the adder in analyzing RFO responses.

The GHG value will be added to the prices bid in future RFOs, and will be used to develop a more accurate price comparison between and among fossil, renewable and demand-side bids. Regardless of which bid is ultimately selected,

[142] PacifiCorp, IPC and EIA estimates sited in NRDC opening brief, 10/18/04, p.16-17

the adder *will not* be paid to that generator or charged to ratepayers; it is an analytic tool only. Winning bidders are to be paid the prices that they bid. Thus, the effect of the adder is to potentially change which bids and resources are selected - not to change the price of selected bids. Bidders must provide the electricity products sought in the all-source solicitations before the IOU will be required to employ the GHG adder.

In addition to the GHG adder, the IOUs are directed to employ, when finalized and approved by the Commission, the additional environmental avoided cost values under development in the Avoided Cost Rulemaking (R.04-04-025). It is anticipated that these values will be adopted in approximately March 2005, and will include a fixed value for GHG (not simply a range) as well as values for other, non-GHG pollutants. Other GHGs, in addition to carbon, will also be included. These values should be added to any fossil bids the IOUs receive in response to an RFO. All procurement commenced subsequent to this decision should employ the GHG adder adopted in this decision, until replaced with a decision in R.04-04-025, when analyzing bids. Additionally, the IOUs will use the values adopted in R.04-04-025 in their next LTPPs when modeling alternative resource portfolios and selecting a preferred portfolio.

In a separate phase of this proceeding, we will be evaluating a procurement framework modeled after the cap-and-trade principles of the Sky Trust.[143] Under that proposed framework, the Commission would establish annual limits on carbon-based energy procurement as a means to meet the

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[143] R. 04-04-003, Appendix B.

Commission's EAP goals and minimize utility contribution to climate change. We will address the effectiveness of this proposal, as well as other approaches to "carbon caps" on utility procurement, to minimize utility contribution to climate change, in subsequent decisions in this rulemaking docket or other appropriate proceedings. For this purpose, the Assigned ALJ and/or Assigned Commissioner may direct Commission staff to perform additional analysis or studies, as needed. We intend to put in place a procurement incentive framework after considering the cap-and-trade Sky Trust proposal as well as other approaches (e.g., specific carbon emission limits) by the end of 2006, or as soon as practicable.

Application of the GHG adder is not required for contracts less than five years in duration, which is the standard adopted in this decision regarding requirements for Commission pre-approval. For contracts longer than five years, the adders should be employed in evaluating the cost of power procured in 2007 and beyond (i.e. power delivered in 2005 and 2006 should in no instances have the adders applied when costs are evaluated by the IOU).

G. Repowering

West Cost Power refers collectively to the limited liability companies that own and operate approximately 2,300 MW in Southern California. The power plants producing those MWs are Encina, El Segundo and Long beach. These are extant power plants that are often referred to as "aging" power plants, and/or facilities on “brownfields.”.[144] WCP urges the Commission to recognize the crucial role of these aging power plants in the electric system and recommend the Commission recognize and respond to the threat of aging power plants retiring before they can be replaced with new capacity. WCP recommends that the Commission make a finding that redevelopment of conventional resources in load pockets is a valuable resource and that the IOUs should be directed to give high priority to such brownfield resources before they consider the use of conventional resources at greenfield sites. WPC believes that redevelopment of an existing site is good public policy that benefits California. In WPC’s opinion, repowering at existing sites, that are already interconnected to gas transportation system, possess rights to water needs, have acquired environmental permits, and have in-place measures to mitigate environmental impacts, would allow redeveloped plans to come on-line faster than comparable greenfield plants.

WCP argues that the EAP and the Commission have recognized the importance of repowering older, less efficient plants and believes the IOUs should be directed to respond to those policies by giving priority to repowering and redeveloping existing power plants. WCP suggests the following:

> Short-term: Continue to use RMR contracts.
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> Mid-term: The Commission must ensure that the IOUs enter into multi-year local reliability contracts with power plants in key locations. This would include contracts with three to five year terms, directing the IOUs to revise their resource plans to

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[144] Brownfield sites generally refer to locations where there are existing power plant and/or other heavy industrial facilities. Greenfield sites, on the other hand, generally refer to locations that currently do not have power generation facilities and/or other heavy industrial facilities already on site.

> show how congestion and local reliability are considered in their procurement decisions. SDG&E should be required to conduct a comparison between the overall cost of its proposed new 500 kV line and the costs of new generation resources located at the site of existing generation in its service area, and to apply RA principles to load pockets.
>
> Long-term: The Commission should recognize the benefits of siting new generation at the existing sites of aging power plants and adopt a policy to promote construction of new generation units at brownfield sites rather than green field sites.

SCE disagrees with WCP's position that brownfield sites should receive priority over other options. SCE points out that WCP's position is self-serving and that the majority of parties, including ORA, agree with SCE. SCE argues that WCP’s position is that all repowered sites receive preference over new generation, not just the ones that are located in load pockets. SCE argues that these plants already possess significant location market power, which the Commission will further exacerbate by giving them priority in RFPs. SCE states that the Commission should not favor these plants if they cannot win an RFP when compared to new generation. SCE suggests RMR contracts for these plants to limit their market power. SCE argues that the benefits of brownfield sites such as the proximity of existing sites to the load center, access to transmission lines and natural gas infrastructure, possession of permits required for operation, possession of rights to water and others are already accounted in SCE' selection of LCBF resources. SCE notes that these advantages benefit the developer by substantially reducing the cost of the project and increasing the competitiveness of the brownfield over the greenfield sites. In SCE's opinion these plants should not be favored over new generation if they cannot compete cost-effectively with new generation.

Instead, SCE suggests that these aging power plants enter into RMR contracts, which limit the market power of such plants, sell into the spot market, or enter into short-term contracts. SCE also notes the risk of entering into contracts with sub-investment grade companies such as Dynegy or NRG (WCP's owner). SCE argues that the LCBF should be the overarching principle of procurement for providing the best value to its customers.

Dynegy advocates continued availability of existing capacity pending implementation of RA, CAISO market design and the creation of a supporting capacity market structure.

SDG&E believes that it should not be directed to sign multi-year contracts with aging power plants in its service territory as a strategy for preserving these plants regardless of whether or not SDG&E has a need for such resources. SDG&E notes that it should not provide a preference for brownfield sites in its resource plan. SDG&E believes that there is no need for a preference in a competitive solicitation.

1. Discussion

Parties have presented two issues: (1) Whether the IOUs should be directed to sign multi-year contracts with aging power plants, and (2) Whether IOUs should give priority to brownfield sites over greenfield sites.

Several parties recommend that the Commission direct the IOUs to sign multi-year RMR contracts with local aging power plants. PG&E seems to agree with this recommendation, while SCE and SDG&E oppose it. PG&E asks the Commission for authority to enter into multi-year contracts in 2005 and states that these types of contracts could help keep facilities, including the aging power plants, on line.

Although the Commission has adopted the policy to minimize reliance on RMR contracts, it has recognized that RMR contracts will remain in the future to address market power. Furthermore, local reliability, and deliverability govern the need for RMR contracts. While we recognize the advantages of IOU contracting with some power plants in minimizing the need for RMR contracts, we do not direct the IOUs to engage in a particular contract, if that contract is not in the best interest of the ratepayers. The Commission has adopted the policy of LCBF which dictates that the IOUs obtain the best and most cost effective product for their customers.

As WPC states, developing brownfield sites is consistent with the Commission and the EAP's stated policies. In recognizing the importance of repowering, in D.04-01-050, the Commission stated that:

> "To the extent that new generation resources are required, the utilities should first consider the overall advantages of repowering at existing plants or of development of brown field sites located close to load rather than development of new green field sites remote from load and requiring substantial transmission and other upgrades to the system. We prefer that generation assets be sited in California and that they minimize the overall economic and environmental impact, including the costs of transmission and power losses."

Also, the EAP has a stated action to: "Add new generation resources to meet anticipated demand growth, modernize old, inefficient and dirty plants….."[145]

To this end, we agree that modernization of old, inefficient, and dirty plants should be among IOUs' first choices of resources. However, we are concerned that the LCBF process would not allow positive attributes of a brownfield site to be fully considered or fairly assessed (for example, the risk of delay in construction of a new site). We disagree with SDG&E's position that the RFP Process should automatically incorporate the positive attributes of the brownfield sites. It is generally good policy to consider brownfield sites before developing greenfield sites, because of existing infrastructure, being close to load centers, and many other benefits. Therefore, we direct the IOUs to consider the use of brownfield sites first and take full advantage of their location before they

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[145] EAP, p. 6

consider building new generation on greenfield sites. If IOUs decide not to use brownfield, they must make a showing that justifies their decision.

IX. Other Procurement Issues

A. Resource Adequacy Issues Not Addressed in the Resource Adequacy Decision

The RA decision, D.04-10-035, accelerated the target date to June 1, 2006, for the IOUs to acquire their reserve margins of 15-17% as established in D.04-01-050. Comments on the PD in the RA decision were circulating concurrently with the post-hearing briefs in the LTPP portion of this proceeding. Numerous parties raised the same issues in the post-hearing briefs as well as in their comments to the RA PD. In particular, parties weighed in on the creation of a multi-year forward commitment obligation. This topic is clearly specific to the RA decision since it is related to the design features of that program and it is appropriate to visit it in Phase II of RA.

Parties also raised the issue of the treatment of resource acquisitions over 17%. D.04-01-050 established the reserve margin requirement of 15-17%, and D.04-10-035 accelerates the due date, but does not change the 15-17%. Some parties interpret the RA range to mean that 15% is desirable and up to 17% can be acceptable temporarily due to lumpiness issues. Others view 16%, the average of 15-17%, as being the target. Still some parties argue that only acquisitions over 17% should raise any issue of penalties or disapproval. Since the RA phase is designed to handle the reserve margin issues we will not rewrite D.04-01-050 in this decision. If parties want further clarification on the interpretation of the 15-17% requirement they should bring it up in Phase II of the RA portion of this docket. This LTPP decision is not intended to change or modify any aspect of D.04-10-035. Any clarifications, alterations or augmentations to D.04-10-035 will be deferred to Phase II of the RA aspect and not addressed here.

B. Local Reliability as Part of the Procurement Process

D.04-07-028, issued in July 2004, established temporary local reliability requirements. Parties presented a full spectrum of viewpoints on this topic in their post-hearing briefs from deferring procurement until locational requirements are more fully defined, to wanting the IOUs to procure now.[146] While we expect RA Phase II to provide further guidance to the utilities in their procurement efforts to meet local reliability requirements, in the interim we extend the requirements of D.04-07-028. In particular, we underscore the direction provided in the July Order to procure and dispatch resources in a manner that considers real-time CAISO operational requirements and all known or reasonably anticipated CAISO related redispatch costs. We expect that the utilities will incorporate CAISO related must-offer, redispatch, and other related costs when undertaking procurement pursuant to the authority provided in this decision. SDG&E is a unique case among the three IOUs in that within service area resource additions almost certainly will provide local reliability benefits, unlike SCE or PG&E.[147] We therefore direct SDG&E to pursue the EAP loading order priorities when it makes resource additions.

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[146] See also discussion of local capacity requirement and deliverability under: Enhanced Supply to Load Pockets.

[147] We note that this statement pertains to new resources within the SDG&E service territory and may not hold true for power purchases outside of San Diego that may encounter transmission constrains getting the power into the San Diego region thus lacking the resource deliverability the Commission has directed. We therefore

Footnote continued on next page

C. Bottom-up Planning

Prior to the restructuring of the electric utility industry in California, the utilities were actively involved in integrated resource planning. With the passage of AB 1890 and the restructuring of the industry, the utilities moved away from active involvement in resource planning and became merchants of power on behalf of their customers. Since the California energy crisis, the pendulum has begun to swing back in the other direction again. The utilities are more actively involved in developing, as well as contracting for, the resources required to serve their customers. Naturally, this has led to renewed interest in making sure that the choices reflect the best trade-offs among the uses of society's limited resources.

In the January 2004 Policy Decision (D.04-01-050) we stated that by relying on a bottom-up approach to system planning, "[t]he Commission and utilities would be able to ensure that state policies are implemented in a manner designed to contain cost while achieving other goals. Such a process is not merely consistent with the state's broader policy goals – it will help sustain them."[148] That decision discussed integrated resource planning as a vehicle to provide a comprehensive context for all of a utility's resource decisions. The ACR/Scoping Memo in the current proceeding requested that the topic of

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underscore the importance of adhering to the direction provided in D.04-07-028 with regard to power purchases in the interim until the ISO market redesign proposal is fully implemented.

[148] D.04-01-050, p. 97.

bottom-up planning be included in the utilities' long-term plans.[149] All three utilities included discussions of bottom-up planning in their long-term plans as requested.

PG&E notes that it has followed the Commission's direction regarding planning, including following the EAP Loading Order, which was developed since the last long-term plans were filed. PG&E states that in its LTPP it has integrated the results of the CAISO-sponsored annual Assessment Studies and Electric Transmission Expansion Plan process into its integrated resource planning. The LTPP describes the processes underlying its adoption. PG&E will compare the most promising identified generation or demand response alternatives with the Commission-approved plan, and examine the planning level costs of all transmission, generation, and demand response alternatives. PG&E asserts that its account services representatives have historically looked at the individual needs of customers, practicing local planning at the lowest level, and will do so even more in the future as the utility acquires an increased portfolio of EE, DR, and DG resources.

SCE's LTPP described the annual planning process it uses to identify projects necessary to serve new load added to the utility's transmission and distribution system. SCE begins with development of 10-year peak-load forecasts for each substation in the SCE distribution system. These forecasts are developed using a bottom-up approach which takes advantage of the Company's regional engineers' knowledge of the local areas. Those substation-level

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[149] OIR 04-03-003, Assigned Commissioner's Ruling and Scoping Memo, June 4, 2004, p. 7.

forecasts are then compared to, and reconciled with, system demand forecasts developed using a top-down approach. Identification of system requirements requires technical studies performed as part of the load-growth planning process, which determines whether expected growth can be accommodated through the existing distribution system, or what kinds of projects are required to bring the system back to within specified loading limits. Development and evaluation of alternatives identifies alternatives for correcting any projected system deficiency. Finally, selection, approval and budgeting result in identification of the best combination of system performance, reliability, operational flexibility and cost to select a preferred plan from among the alternatives.

SDG&E states that because its entire service territory constitutes a single load pocket, the solutions offered for the service territory in total are identical to those envisioned by the Commission in its discussion of bottom-up planning. SDG&E has been an active participant in numerous regional planning and energy policy forums, as well as discussions with customers and other stakeholders, and has used any gained insights in its planning process. This approach includes, but is not limited to, working with the CSD to assist in meeting the goal of installing 50 MW of renewable resources by 2013 and finding ways to promote further development of, and explore possible future sites for, solar facilities in the San Diego region.

The three utilities have presented information on the processes they undertake to develop bottom-up forecasts of their needs and of the plans to deal with those needs. We are satisfied that the utilities are seriously following our direction and taking into account the needs of local areas within their service areas in developing their plans.

D. DWR contract allocation and reallocation (Sunrise)

The June 4, 2004, ACR/Scoping Memo provided the IOUs with conventions for DWR contract allocation and reallocation to be used in their modeling. The ACR asked the utilities to assume that the new DWR contracts, Kings River and CCS, be allocated to PG&E as proposed by DWR, and Sunrise allocation remain as is with SDG&E.

PG&E presented no DWR issue in this proceeding. SDG&E, although its position is that the DWR Sunrise contract should be reallocated to PG&E, conformed with the directions from the ACR and included Sunrise in its resource portfolio. SCE had no issue concerning DWR contracts for this proceeding.

There is another proceeding, A.00-11-035, that is addressing the subject of cost allocation of DWR contracts. Therefore, except for including DWR contracts in the utilities' resource portfolios, there is no DWR contract issue.

Therefore the arguments presented by SDG&E that keeping Sunrise in its plan reduces its option to address local reliability issues because Sunrise is outside the territory, provides no benefit to local reliability and leaves the utility with no "headroom" to add a local resource till the contract expires in 2010, and ORA's proposal that SCE contract with SDG&E for dispatch rights for specific units under the DWR-Williams contract, will be addressed either in the next phase of RA, or in the DWR contract proceeding.

DWR requests that this decision clearly state that nothing in this decision makes changes to prior Commission decisions, particularly D.02-12-074, the IOU-DWR Servicing Agreements, or makes any changes in ratemaking treatment of the DWR contracts. We think DWR's request is reasonable and we adopt it until further Commission action on the subject.

E. Long-Term Planning in the Next Procurement Cycle

D.04-01-050 determined that in future cycles of the procurement process, we would link our timing to that of the CEC's IEPR. Since that proceeding operates on a biennial calendar, by stature, that means that the next long-term procurement proceeding will be in 2006. D.04-01-050 also linked the substance of the analyses we direct IOUs to file with the results of the CEC's IEPR information and analyses. In the past two years, the CEC and this Commission have been collaborating to a much greater degree than ever before, and as evidence the CEC is not a party to this proceeding and its staff is assisting our own staff in reviewing the IOU LTPPs and in developing resource adequacy procedures.

On September 16, 2004, President Peevey issued an ACR/Scoping Memo addressing further integration between the CEC's IEPR and our next procurement proceeding. That ACR suggested a specific type of coordination between the 2005 IEPR and the 2006 procurement proceeding. In essence, the CEC's IEPR would review IOU load forecasts, conduct a resource assessment and identify the range of need for new resource additions addressing significant uncertainties for each IOU. Our 2006 procurement proceeding would not relitigate those results, except in those cases where there is new information that was not available to be considered in the CEC's proceeding, and our 2006 procurement proceeding would address IOU resource procurement proposals and strategies in light of the range of need identified in the 2005 IEPR. We will also consider how CEC statewide policy recommendations may be translated into IOU-specific directives, given the circumstances of each IOU. A more specific enumeration of proposed relationships between this Commission, the CEC, and the CAISO is attached as Appendix B.

We endorse the coordination agreement and the direction to IOUs stated in the September 16, 2004 ACR. We direct IOUs to participate in the CEC IEPR proceeding as the one forum in which long-term load forecasts, resource assessments and need determinations will be considered. We believe Appendix B constitutes a good foundation for coordinated proceedings and the minimization of duplication between various planning proceedings. We direct our staff to work with the CEC and CAISO to effectuate this agreement in a complete and practical manner.

F. Utility filings demonstrating compliance

In prior Commission decisions issued in R.01-01-024, we established the following filing requirements:

Filing	**Decision**	**Function**
Monthly ERRA Report	D.02-12-074 (OP 19)	Shows the activity in the ERRA balancing account with copies of original source documents supporting each entry over $100.00 recorded in the account.
Monthly Portfolio Risk Report	D.03-12-062 (OP 2 and 4)	Informs the Energy Division on the risk exposure of the IOU's procurement portfolio.
Quarterly Transaction Report	D.02-10-062 (OP 8)	Tracks procurement transactions and shows that they comply with the approved procurement plan.
Semiannual ERRA Application	D.02-10-062 D.02-12-074 D.04-01-050	Sets electric energy procurement forecast rate. Enacts trigger, if met. Reviews contract administration and least-cost dispatch.
Short-Term Procurement Plan (STPP)	D.02-12-074 D.03-12-062	Addresses the procurement products, processes, risk management strategy and tools
Gas Supply Plan (GSP)	D.03-04-029 (OP 6)	Addresses how the IOUs plan to meet their natural gas needs regarding their electricity procurement functions
Long-Term Procurement Plan	D.04-01-050	Addresses how the IOUs plan to meet their electricity needs and incorporate Commission's directives in procurement planning

PG&E requests that the Commission streamline the review of procurement costs through quarterly transaction reports and ERRA proceedings. PG&E states that "by expediting the process for verifying that utility transactions are consistent with adopted procurement plans, the Commission can confirm that the utilities' procurement transactions are in compliance with an approved procurement plan and eliminate any second-guessing during subsequent ERRA compliance reviews… The Commission should require that the reviews be completed on time and the scope should be limited to review of the transaction identified by the independent auditor."[150]

PG&E proposes the following: (1) Issue an omnibus resolution approving all unprotected, unresolved, quarterly procurement transaction advice letters as submitted, and (2) focus on truing up forecasted expenses to actuals in the ERRA compliance review proceeding and review the transactions identified in the quarterly transaction review process that are noncompliant with the procurement plan.

SDG&E recommends that the semiannual Gas Supply Plans be consolidated into the ERRA/STPP process, "as gas is an integral part of least-cost dispatch and short-term procurement planning and consolidation would eliminate redundancy, thus easing the resource constraints for both the Commission and SDG&E."[151] Furthermore, SDG&E proposes that advice letter updates to the forecasts contained in the plan be filed in conjunction with each

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[150] Ex. 34, p. 2-44

[151] SDGE/McClenanan opening testimony, p. 12.

utility's ERRA forecast and that authorization would be for a rolling five years. SDG&E also recommends that gas supply plans be consolidated into the ERRA/STPP.

SCE suggests that the AB 57 plans need not be updated on an annual basis, and not in the ERRA proceeding. Instead, AB 57 can be updated as needed, e.g. if there were changes in the LTPP that required it.

DWR opposes SDG&E's recommendation that the Commission consolidate the review and approval of gas supply plans into the ERRA proceedings, stating that the recommendation is not consistent with the contractual obligations of SDG&E under its current Operating Agreement with DWR.

ORA recommends annual reviews of procurement plans in ERRA proceedings.

We continue the requirement for the Monthly ERRA Report and Monthly Portfolio Risk Report. In regards to the Quarterly Transaction Report, the IOUs are ordered to file a joint proposal to reformat the report in a way that will provide the Commission concise and coherent information, thereby streamlining the review process. The objective of the report is to show that the transactions entered into are in compliance with the upfront standards identified by the Commission. These reports will be reviewed by the ED staff. If there are no protests and the staff concludes that the transaction entered into in that quarter comply with the utility's procurement plan, then by the Commission's Expressed Delegation of Authority, the ED Director can approve the reports. However, if there are substantive protests and the staff takes issue with certain transactions, the staff will issue a draft resolution for the Commission's approval.

We find that no change is necessary at this time for the Semiannual ERRA Application. As for the STPPs, the 2006 LTPPs will contain the features of the Short-Term Plans that are not covered by the proposed 2004 LTPPs. That is, ultimately, we will eliminate the STPPs and the IOUs will act in accordance with a single Commission-approved plan. Until then, the existing STPPs will be in effect. Any updates to the existing STPP's should be filed with an AL 30 days after the issuance of this decision.

In regards to the semi-annual Gas Supply Plans and the biennial LTPPs, we find no change is necessary at this time.

G. Collateral Requirements

As part of its regular operation in a hybrid energy market, SCE periodically contracts with numerous counterparties for various electric and natural gas products. Counterparties require SCE to post collateral in the form of "cash or letters of credit if their exposure to SCE exceeds a predetermined negotiated limit (the Unsecured Credit Limit)." According to SCE's long-term plan:

> "The requirement to provide collateral stems from a contracting counterparty's concerns that SCE will be unable to meet its obligations under the contract. These counterparties may be either physical buyers of SCE's excess energy or sellers of energy, capacity, or natural gas to SCE. SCE may also enter into financial transactions which act to hedge ratepayers' exposure to future market price movements.[152] In each case, the transaction counterparties will

[152] While not all financial hedges will result in collateral requirements, transactions such as financial futures or swaps will result in mark-to-market exposures similar to physical contracts.

> attempt to minimize their risk by requiring SCE to post cash or letters of credit if their exposure to SCE exceeds a predetermined negotiated limit (the Unsecured Credit Limit)."[153]

SCE states that its currently "authorized procurement plan includes sufficient collateral capacity for the near term. However, SCE's ability to stay within the current Commission authorized collateral limit will depend heavily upon the length of new contracts signed to meet resource needs."[154] SCE has stated its intent "to file an update to its STPP procurement plan within 30 days of the Commission's long-term procurement decision to conform it to Commission policies. If an increase to SCE's collateral capacity is required to carry out the revised plan, SCE will provide updated collateral estimates as part of this filing."[155] No party has taken issue with SCE on this issue. Accordingly, we accept SCE's stated approach.

We also note here that SCE can, and does, require counterparties to make similar collateral postings aimed at ensuring contract performance under changing market conditions. Calpine asks the "Commission [to] be sensitive to the fact that credit requirements can be used to either (i) squelch competition through onerous credit requirements; or (ii) to impose on ratepayers the costs associated with a zero risk tolerance."[156] Calpine warns that if "overcollateralized, project sponsors will be placed at a competitive

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153 SCE Long-Term Plan, Vol.1, July 9, 2004, p.28.

154 *Id.*, p. 31.

155 SCE opening brief, p. 131).

156 Calpine direct testimony, pp. 18-19.

disadvantage … [and that these] excessive credit requirements will be passed on to ratepayers through higher prices."[157] (*Id.*, p.19.) We are not aware of any specific claims of over-collateralization or associated recommendations.

H. New Accounting Rules

SCE has informed the Commission of two relatively new accounting rules promulgated by the Financial Accounting Standards Board (FASB) "that, like the debt equivalence issue, may affect electric utilities' costs of contracting for power."[158] One rule would require "utilities to include certain long-term contracts as liabilities on their balance sheets by deeming them capital leases,"[159] and the other rule (FASB interpretation) "could impose additional balance sheet impacts on utilities signing long-term contracts"[160]

According to SCE, "a capital lease requires a utility to book the plant as an asset (similar to the accounting treatment for a utility-owned plant), and to record the present value of the expected lease payments as long-term debt on its balance sheet."[161] The second rule may require SCE "to consolidate [certain

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[157] *Id.*, p. 47).

[158] SCE Long-Term Plan, Vol.1, Exhibit 73, pp. 47-50.

[159] EITF Issue 01-08, "Determining Whether an Arrangement Contains a Lease," May 15, 2003, effective for new or revised power contracts entered into after June 30, 2003.

[160] FASB Interpretation No. 46 (revised December 2003) "Consolidation of Variable Interest Entities—an interpretation of ARB No. 51."

[161] SCE Long-Term Plan, Vol.1, Exhibit 73, p. 49.

counterparties in its balance sheet] for financial reporting purposes."[162] SCE has not requested any specific relief related to these new accounting rules.

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[162] *Id.*, p.

We observe here that consideration of such accounting rules may have been more appropriate in the COC proceeding. Since SCE contends that these new accounting rules are somewhat similar in effect to debt equivalence, SCE may seek further guidance from the Commission when appropriate and in the same manner as set forth in the COC proceeding.

I. Standard Offer Service

Constellation proposes a slice of load utility procurement mechanism to provide "standard offer service" (SOS). It is a wholesale power procurement approach whereby a jurisdictional public utility secures all or a portion of the generation supply to meet its retail load through a multi-year wholesale service contract or contracts with a third-party provider or providers. Constellation envisions that SOS would be procured through a competitive bid process approved by the Commission in advance and conducted with Commission oversight. Winning bidders would enter wholesale service supply contracts with the utility. The utility, in turn, would provide the ultimate retail service to its customers in fulfillment of its obligation to serve. Constellation explains that this service can be contrasted with the traditional procurement approach. In traditional service, utilities secure quantities of capacity or energy to serve loads subject to subsequent prudence reviews by regulators, while the SOS procurement approach uses a competitive solicitation process to secure generation service related to some percentage, or "slice" of the utility's load, which will vary in quantity from time to time.

According to Constellation, there are advantages to the utilities from SOS. It can transfer risks associated with load migration away from the utility to the wholesale supplier, removing the potential for new stranded costs or the need to impose new nonbypassable charges. It transfers some price risk and performance risk to the SOS provider. It promotes a diversity of suppliers and market entrance points, creating a portfolio of supply arrangements.

Constellation states that some form of the SOS approach is currently used in Maryland, New Jersey, Maine, Massachusetts, Connecticut, and New Hampshire. And since the close of the record in this case, the District of Columbia has adopted a SOS procurement mechanism modeled after Maryland's approach.

SOS may be a useful mechanism for wholesale procurement by LSEs, and it may be appropriate for California once it is further developed and considered. SOS is substantially different from the procurement methods currently being used by the IOUs, and we do not have the knowledge or confidence to mandate SOS at the present time or on the basis of the current record. This topic should be further developed by participants in the second generation of topics for the RAR process, for it is a companion to another topic to be considered, the development of markets for trading capacity.

J. Confidentiality

Consistent with the Commission's direction in D.04-01-050, it is our intention that many more categories of planning information will be open and will be considered so in our review of the IOUs' LTPPs. We have yet to determine if any information that routinely was considered confidential under former protocols might be deemed public when this decision is issued in final. We are still trying to balance the competing interests of the need of some confidentiality of IOU data to protect ratepayers, against the public interest in disclosure and the desire of intervenors to have better access to IOU confidential data to more fully participate in Commission proceedings. In D.02-08-071 we established the PRG process, and we continue to find it useful for certain procurement actions to be previewed and reviewed by the PRGs. While we favor "open decision-making" we need to be pragmatic about mitigating any adverse ratepayer consequences.

Since this OIR was issued, the Legislature passed, and the Governor signed, SB 1488[163] that directs the Commission to "initiate a proceeding to examine its current confidentiality rules under Pub. Util. Code §§ 454.5 and 583 and the California Public Records Act[164] to ensure that the Commission's practices under these laws provide for meaningful public participation and open decision making."

Currently under AB 57, that added Section 454.5 to the Pub. Util. Code, the Commission is to have in place procedures that ensure the confidentiality of any market sensitive information submitted by an IOU as part of its proposed procurement plan, while ORA and other consumer groups that are not market participants (NMP) have access to the information under confidentiality provisions. This provision of AB 57 was an attempt to balance the compelling ratepayer interest in ensuring that certain legitimately confidential information is kept out of the hands of those who can use it to manipulate wholesale energy markets, with promoting a sufficiently transparent decision-making process to allow for scrutiny and review by the legislature and the public.

Working from AB 57 and the additions to the Pub. Util. Code, when the Commission initiated R.01-10-024 on October 25, 2001, to establish policies and

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[163] SB l488, (stats.2004,Ch.690, Effective September 22, 2004).

[164] Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code.

cost recovery mechanisms for generation procurement and renewable resource development, the assigned ALJ issued a ruling establishing a Revised Protective Order on May 1, 2002. That protective order remained in place throughout 2002.

In early 2003, the ALJ reopened the issue in response to concerns that certain MPs and other entities did not have adequate access to information under the existing protective order. A revised ALJ ruling issued on April 4, 2003 [joint Walwyn/Allen ALJ ruling] allowing the CAISO, and other NMP access to the same confidential information the consumer groups had with the direction that they must treat protected materials as confidential vis-à-vis third parties.

Following a request from SDG&E to amend the April 4, 2003, ALJ ruling to protect information submitted by parties to a RFP, the ALJ issued a ruling on December 1, 2003, modifying the previous protective order allowing certain bid information to remain confidential, but also soliciting comments on a further change to the protective order to incorporate a provision allowing outside attorneys and/or consultants to a MP who do not perform competitive duties for or on behalf of their client, and who execute a Non-Disclosure Certificate, to have access to materials relevant to the SDG&E RFP. Parties were directed to draft a Protective Order that paralleled language from an Amended Protective Order adopted by a FERC judge.[165] On January 14, 2004, following the receipt of comments on the FERC model, the ALJ issued a ruling adopting an Amended Protective Order (APO) that was substantially consistent with the FERC orders and that allowed the MPs access to Protected Materials following the FERC

[165] FERC Docket Nos. EL02-60-003 and EL02-62-003. See footnote 16.

guidelines. As referenced earlier in this decision, this APO controlled confidentiality issues in this current procurement proceeding.

In preparation for review of the IOUs' LTPPs in this proceeding, in D.04-01-050 the Commission expressed its desire to move towards more open and transparent decision making and asked the parties to submit comments on how to allow more access to utility data, but not at the expense of the ratepayer/consumer. Comments were received on March 1, 2004, and in summary, PG&E, SCE and SDG&E argued against increased disclosure, ORA/TURN favored more public disclosure and offered some guidelines, and the MPs were the most forceful in arguing for an open, transparent and competitive process. By that time SB 1488 was already in committee, so instead of issuing a new iteration of the January 14, 2004, APO we followed the guidelines implemented therein for this procurement proceeding.

We recognize our SB 1488 obligations and forthwith we will initiate a Rulemaking to fulfill our obligations under SB 1488. In initiating this new rulemaking, we will treat the CEC as a collaborating agency and not as a party so that we can develop confidentiality rules as closely aligned with one another as possible. We will also review the status and effectiveness of the PRGs in that Rulemaking. For purposes of this decision and our review of the IOUs LTPPs, we believe intervenors, including MPs, had sufficient access to the IOUs' background data and assumptions, if they chose to follow the guidelines of the January 14, 2004 APO to allow for a robust evidentiary hearing and development of the record to satisfy us that there was a full vetting of the important issues.

We also note that more intervenors, in particular the environmental groups, had access to the IOUs confidential data since they signed on to the APO. So in addition to the consumer groups, other NMP also had the benefit of reviewing all the utility data. None of the MPs chose to sign on to the APO. It may be the case that the utilities and the MPs have reached a point of equilibrium in that if the MPs had more access to utility information, the utilities may have demanded equal access to MP information.

X. Comments on the Proposed Decision

The proposed decision of Administrative Law Judge (ALJ) Brown in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were received from the following parties on December 6, 2004: CAC/EPUC; CAISO; Calpine; CCC; CEERT; Chula Vista; CLECA/CMTA; Constellation; CUE; DENA; DWR; IEP; Modesto; NRDC; ORA; PG&E; SANDAG [166]; SCE; SDG&E; SEGE; SSJID; Strategic Energy; SVMG; TURN; UCAN; UCS; WCP; WPTF. On December 13, 2004, reply comments were received from: CEERT; NRDC; ORA; PG&E; SCE; SSJID; Strategic and TURN. Following is a summary of the parties' comments and reply comments and a discussion of the modifications or clarifications the Commission adopts.

PG&E

In its comments to the PD, PG&E requests that the Commission change the PD to: (1) clarify the cost recovery for IOU owned generation; allow PG&E to continue with its current solicitations without an Independent Evaluator (IE) and for future solicitations, an IE is only required if there are affiliate bidders;

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[166] Concurrently with the filing of comments, SANDAG filed a Motion to Intervene, which motion is granted in this decision.

(3) clarify that bids should be evaluated for LCBF; (4) approve a DE of 30%; (5) order that contracts with terms of ten years or less do not need preapproval; (6) see that compliance filings are expeditiously processed; and (7) clarify that the duration of stranded cost recovery mechanisms should be the same as the duration of PG&E's new commitments, especially in light of the fact that new renewable projects require long-term commitments in the range of 10 to 20 years.

SCE

SCE requests that the Commission change the PD in the following areas: all-source RFOs should not have IOU and turn-key projects competing with PPAs; all customers, not just bundled service customers, should pay for stranded costs for the length of the contract; contracts up to five years should be allowed without preapproval; Liquidated Damage contracts should be allowed to count for RA purposes; full DE consideration should be allowed; the ban on affiliate transactions for all transactions should be lifted, not just for long-term contracts; and the scope of the ERRA disallowance cap should be clarified. In its comments filed December 6, 2004, SCE opposed the requirement of a GHG adder in evaluating proposals. However, since that time SCE has modified its stance and now supports the GHG adder to the evaluation of new utility commitments or contracts with terms greater than five years.

SDG&E

SDG&E details in its comments where it believes the PD needs revisions. Specifically, SDG&E urges that DE be 30%, instead of the 10% in the PD; believes employing a GHG adder is premature, or if one is adopted, it should apply to all resources; finds the requirement to file additional DR programs duplicative; seeks clarification as to the provider of last resort vis-à-vis CCA and resource planning; wants compliance filings tied to a 30-day time frame if there are no protests; wants the discussion on procurement risk committees eliminated; and seeks other revisions and/or clarifications.

ORA

ORA supports certain aspects of the PD, especially the endorsement of the GHG adder, the coordination of forecast planning with the CEC's IEPR and the deferment of the approval of SDG&E's 500 kV lines. However, ORA does question the adoption of DE, the use of an IE for certain resource procurements and the adoption of ten/twelve of SCE's proposed modification to the 2004 procurement decision. ORA thinks DE should be deferred to the cost of capital proceeding and adopting it in this procurement decision is in direct contradiction with other Commission decisions. And, ORA asks the Commission to reconsider the use of an IE since ORA believes there is no guarantee that an IE contributes transparency or insures that the bid solicitation and selection is fair.

TURN

Initially TURN advocated that the Commission preapprove contracts over three years in length. TURN has reconsidered its position and now recommends preapproval for contracts over five years in length. This comports with the recommendations of most of the other parties. With that clarification, TURN's primary focus in the comments is on protecting bundled customers from unfairly being burdened with stranded cost. TURN argues against the ten-year recapture period and instead urges the Commission to have all who benefit from a utility's procurement of new resources pay for the life of the contract. TURN also seeks clarification on IOU cost recovery for utility-owned resources. In addition, TURN advances again its argument in favor of having PG&E and SCE solicit bids to obtain 500 MW of new capacity each as interim agents of the Commission's RA policy. And finally, TURN asks the Commission to clarify that all IOUs are expected to issue RPS solicitations in 2005; that the GHG adder will only apply to resource commitments of greater than five years in length; that a potential CCA could present the utility with a binding "notice of intent" that would terminate the IOU planning responsibility for the affected load and the CCA's customers would not bear stranded cost responsibility; allow any firm LD contract to be eligible for RA counting purposes until there is a decision in Phase 2 of the RA decision; and specify that intervenor compensation is available for participation in processes that will feed into the next round of LTPP filings.

UCAN

UCAN supports the PD in many respects, especially in the areas of ratification of the EAP's loading order, denial of SDG&E's 500 kV line, requiring the "maximum feasible amount of renewable generation," the finding that the transmission elements of the plans were insufficient for both Commission and CAISO's purposes, the order to the IOUs to file updated gas forecasts and the determination that local reliability should be part of the procurement process. However, UCAN found the PD deficient in the following areas: it fails to provide a realistic mechanism to implement the EAP loading order; there is a lack of the traditional resources proposed; there is no mechanism to integrate EE, DR and renewables later in the LTPPs; the IOUs' LTPPs are approved; it fails to consider local transmission constraints in the SDG&E service territory; and wrongly concludes that SDG&E's bottom-up planning process is acceptable. UCAN urges the Commission to modify the PD to correct these deficiencies.

UCS

UCS overall supports the PD but offers suggestions for revisions it opines would ensure greater consistency with the EAP and prior Commission directives and facilitate future IOU planning and procurement. In particular, UCS recommends that the Commission order a single supplement/compliance filing by the IOUs in March 2005 for their LTPPs as the vehicle for their updates, rather than doing it piecemeal with multiple updates and filings. In addition, UCS urges the following revisions to the PD: require the IOUs to perform sensitivity analyses of GHG adders by using a range of values and clarify the adder is being used to mitigate financial risk not to quantify externalities; direct the IOUs to use the GHG adder in the development of LTPPs as well as in the evaluation of procurement bids; acknowledge UCS' contributions on the subject of GHG; clarify that the IOUs are to conduct RPS solicitations pursuant to rules already established by the Commission and in addition conduct all-source RFOs that invites renewable participation; streamline transmission planning requirements to accommodate renewable resources; adopt a 5% DE for renewables; require the IOUs to model a range of gas price forecasts; provide greater guidance on how the IOUs are to add clean, fossil-fueled generation pursuant to the EAP loading order and clarify that intervenors participating at the CEC in energy planning activities will be eligible for CPUC intervenor compensation. In addition, UCS wants PG&E and SCE to revise their renewable resource analyses to mirror SDG&E's plan that includes a considerable amount of detail.

CEERT

CEERT commends the PD's policy statements in furtherance of promoting environmentally responsible energy generation but suggests modifications and clarifications that will signal that the Commission is not altering or delaying renewable solicitations. CEERT urges the Commission to firmly state that the 20% renewables procurement by 2010 is a "hard target," commit to getting rid of the current electric generation fleet that is old, inefficient, inflexible and dependent on scarce and expensive natural gas supplies, and replace it with more renewables by following the current RPS law and permit regular and routine RPS solicitations that meet and exceed RPS targets. In addition, CEERT finds PG&E and SCE's procurement sections inadequate, and like UCS, wants those IOUs to file more detailed plans.

NRDC

NRDC voices many of the same arguments presented by UCS and CEERT. In particular, NRDC supports the GHG adder. But like UCS, NRDC asks that the Commission clarity that the GHG adder represents the financial risk associated with carbon emissions and is not an externality value. In addition, NRDC, like UCS, wants the IOUs to use the GHG adder in developing their LTPPs as well as in evaluating bids, and to include fuel types and different portfolio options in the LTPPs. NRDC also asks the Commission to ensure that future LTPPs are a long-term roadmap against which the Commission can judge individual procurement requests, clarify how the 2006 LTPP will coordinate with the CEC's IEPR, and clarify that RPS solicitations must continue, but that renewables are also allowed to bid in all-source RFOs. And finally, NRDC requests that the Commission clarify that the staff's report on a potential "carbon cap" be coordinated with other state agencies.

Modesto, SSJID and Chula Vista

Modesto, SSJID and Chula Vista, while each uniquely situated, share a common concern about the IOUs over procuring and expecting departing load, whether it departs to a CCA, an irrigation district or a municipality, to pay for stranded costs. All three parties commented that the IOUs' LTPPs do not plan adequately for departing load, and if stranded cost recovery is allowed, the IOUs have no incentive to plan appropriately or wisely. Modesto argues that PG&E regularly forecasts departing load for both Modesto and Merced Irrigation

Districts as part of its resource planning and therefore the utility can predict with sufficient accuracy what load might be lost. PG&E is well situated to prevent stranded costs and therefore Modesto urges the Commission to reject PG&E's request for the imposition of non-bypassable charges. To allow for these charges does nothing to encourage prudent planning for PG&E and thwarts competition.

SSJID presents similar arguments to those advanced by Modesto and argues that allowing non-bypassable charges provides the IOUs with "cover" for what may be unsound procurement decisions. SSJID also asks that the Commission clarify that irrigation districts have the same opportunities as CCAs to work out alternative strategies with the IOU regarding the sharing of procurement risks.

Chula Vista's main concern with the PD is that CCA will not be properly coordinated with the development of the IOUs' LTPPs. In particular, Chula Vista is troubled that SDG&E's plan does not incorporate reasonable anticipated CCA departing load. And in addition, Chula Vista asks the Commission to direct SDG&E to not enter into contracts that will increase departing load charges for CCA and to direct the utility to corporate with Chula Vista in the development and implementation of CCA.

CCUE

CCUE's focus in its comments to the PD is on all-source solicitations for new generating plants. In particular, CCUE does not believe head-to-head competition in an all-source RFO is in the best interest of the ratepayers. CCUE argues that there is such an inherent difference in a plant owned by a utility and dedicated to serving ratepayers based on cost of service for its entire life and a plant owned by a third party whose only obligations are defined by contract. Competition between IOU-owned and PPAs, from CCUE's perspective, is "terrible for keeping on the lights." Following the CPCN process for utility-owned generation and requiring an RFP for PPAs is what CCUE advocates. As an alternative, CCUE favors a hybrid market and the 50/50 solicitations presented bb PG&E.

CAISO

CAISO supports the PD's discussion of how future plans should include conceptual scenarios that illustrate the impact of potential generator location and when an IOU proposes a major transmission line, it should also include a scenario without the line in its plan. CAISO recommends that the Commission adopt guidelines for analyzing load pocket requirements for the 2006 long-term plans should local capacity requirements remain pending in the RA process. CAISO also argues that the PD misstates the RA obligation, fails to consider the effect of expanding the IOUs' contracting authority on the RA program and should clarify that SDG&E can recover its costs incurred in evaluating its proposed 500 kV transmission lines. Finally, CAISO suggests that if D.04-07-028 requirements are to be extended, that they be extended until implementation of local reliability requirements are developed in Phase 2 of the RA proceeding.

DWR

DWR submitted comments on the PD that focused on DWR's power purchase program and asks the Commission to clarify that nothing in the PD makes changes to prior Commission decisions, particularly decisions addressing the IOU-DWR Servicing Arrangements or IOU-DWR Operating Agreements. Additionally, DWR asks the Commission to modify the PD to deny SCE's request to permit SCE to implement a seven-step process for treating DWR costs in connection with its procurement activities, to make it consistent with

D.04-12-014 issued on December 2, 2004. DWR asks the Commission to allocate certain DWR contracts for operational purposes.

SVMG

SVMG focuses on the following in its comments to the PD: (1) its support of all source bidding, the use of an IE, and a cost cap on winning bids; and (2) its argument that the PD, as written, favors renewables beyond what it should with the GHG adder and that could lead to unacceptably higher costs for consumers.

CCC and CAC/EPUC

CCC and CAC/EPUC represent the interest of QFs, and the PD defers all QF issues to a subsequent phase of this case and to the Commission's companion rulemaking on avoided cost pricing, R.04-01-025. In particular, CCC states that while it plans to participate actively in the QF proceeding, it urges the Commission to insure in this decision that there is not a fatal delay that will prejudice the role QFs will play in the IOUs future procurement activities. There are a number of QF contracts that are due to expire during the long term planning period of 2005 through 2014, and CCC fears that unless these contracts are renewed or replaced with new contracts, many QFs, especially cogeneration QFs, may not be able to continue. Therefore, CCC requests that the Commission have a viable policy that requires sustained procurement from cogeneration QFs through out the planning period. Additionally, CCC is concerned that without such a policy, the IOUs will displace cogeneration with other resources.

CAC/EPUC share many of the same concerns as CCC and ask the Commission to insist that the IOUs assume for planning purposes that their QF contracts are renewed and to prohibit the IOUs from displacing QF capacity. CAC/EPUC also argue that the PD should be modified to take out DE, since DE is not a real cost and is anti-competitive since it favors short-term contracts. At the very least, CAC/EPUC ask that DE not apply to QF contracts. CAC/EPUC also want no exit fees for self or co-generation customers, no GHG adder for co-generation and more open and transparent processes before the Commission.

CLECA and CMTA

CLECA and CMTA are concerned with having adequate generation sources available to serve their customers that provide a cost-effective mix of resources. CLECA and CMTA are concerned that the PD puts too much emphasis on renewables at the expense of cost-effectiveness. CLECA and CMTA favor the development of a competitive wholesale market and argue that if the Commission imposes exit fees to collect stranded costs, the IOUs will have no incentive to exercise prudent planning. From their perspective, exit fees are no substitute for sound and flexible planning. CLECA and CMTA favor all source solicitations with the winners selected on LCBF. The groups also favor the use of an IE, but want the Commission, or the ED to select the IE, not the utility. And finally, CLECA and CMTA do not support what they see as the Commission's preference for renewables because their large industrial customers will be saddled with the costs. The groups also oppose the use of the GHG adder.

SEGE

SEGE supports the lifting of the affiliate transaction ban, but wants it lifted for all transactions and for the Commission to allow for "blind" purchases between utilities and their affiliates, not limited to just transactions over three years in length. In addition, while SEGE supports parts of the PD, it urges the Commission to do away with the GHG adder, do away with any preference for brownsites and to not allow any updated gas price forecasts to delay scheduled solicitations. Finally, SEGE argues that DE should only be one of the risks considered in evaluating bids.

Constellation, Strategic Energy and WPTF

Constellation supports the direction the state is going in fostering competitive markets at both the wholesale and retail levels but is concerned that unless the PD is modified, that competitive market is at risk. Specifically, Constellation fears that allowing the utilities to recover stranded costs does nothing to encourage prudent procurement decisions. To address this issue, Constellation proposes a “slice of load” option that the PD rejects. Constellation asks the Commission to not be so hasty in rejecting this option as it would provide competitively procured sources of power for the utility’s bundled service customers without creating the potential for a stranded cost recovery mechanism that restricts, if not eliminates, the ability of customers to choose competitive alternatives.

Strategic Energy is concerned that the PD would start California down a path where all risk for prospective utility procurement is borne by the consumer—if the Commission allows the utilities to recover stranded costs. Then, the IOUs have no incentive to be prudent managers of their supply on a volume or a price basis and CCA and new DA are faced with economic barriers in the form of new exit fees. Strategic Energy also asks the Commission to consider Constellation’s “slice of load” option as a method of protecting bundled ratepayers and promoting competition.

WPTF also supports a competitive market and supports many of the PD’s proposals, especially the rejection of PG&E’s 50/50 hybrid market proposal, the adoption of a cost cap for utility-owned resources, the requirement that IOUs must use an IE in solicitations where the utility or an affiliate presents a bid, the order to the utilities to provide updated gas price forecasts and the adoption of allowing the IOUs to consider a 10% DE in evaluating PPAs. However, WPTF urges the Commission to modify the PD to clarify that tradable RECs are in play and can be used by a utility to meet its RPS targets. In addition, WPTF believes that the GHG adder is not supportable at this time and that deferring local capacity requirements to Phase 2 of the RA proceeding is "ill-advised." And, following along with Constellation and Strategic Energy, WPTF is concerned that allowing the IOUs to recover their net stranded costs will hamper competition and suggests that Constellation's "slice of load" option might be a solution to be studied further.

IEP

IEP is in substantial accord with the PD, but does have some areas of disagreement—especially on the issue of the application of DE as a bid evaluation factor. Other areas in which IEP disagrees with the PD include the GHG adder, the way confidentiality was handled in this proceeding and the fact that the LTPPs did not model the PacifiCorp planning process. Additionally, IEP suggests that cost caps should apply to IOU-turnkey resource selections and the IOUs should not be the contracting party for the IE. With these modifications, IEP supports approval of the PD.

DENA

DENA is primarily concerned that unless immediate steps are taken in the next three to five years in the utility procurement context, existing capacity such as DENA's may be pushed towards early retirement. DENA believes that Ordering Paragraphs (OP) 14 and 15 of the PD provide the utilities with authority to enter into transactions with entities such as DENA, but asks the Commission to clarify the OPs so there is no question that "at risk" existing capacity will not be prematurely retired.

Calpine

Calpine supports the efforts made in the PD to ensure the procurement of resources results from fair, open and transparent competitive solicitations. To insure this, however, Calpine suggests certain modifications to the PD: clarify that the cost cap applies to all IOU-owned resources, including turnkey and affiliate projects; have Commission staff retain the IE; give no priority to Brownfield projects over Greenfield ones; direct that once an IOU has met its RPS target, additional renewable resources should be obtained through all-source competitive solicitations; and deny the IOUs request to consider DE in evaluating PPAs.

WCP

WCP urges the Commission to revise the PD to give consideration to the role aging power plants play in California's electric resource base and to the negative results that will occur if they are retired in the next few years. To this end, WCP recommends that the Commission integrate the IEPR process and the procurement process. In addition, WCP requests the following specific revisions to the PD: revise the terminology re: brownfields, greenfields and repowering so the decision is clear and consistent; add a discussion of the advantages of repowering; declare the Commission's intention to work for a recognition of repowering in the loading order of the EAP and make appropriate revision to the references in the PD to the EAP's loading order; and require the IOUs to modify their LTPPs to incorporate consideration of repowering.

SANDAG

SANDAG basically supports the PD's direction on renewables and EE goals since these policies comport with the direction SANDAG advocates. In addition, SANDAG is working towards more integration between the community and SDG&E in developing SDG&E's 2006 LTPP.

XI. Assignment of Proceeding

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

Findings of Fact

1. The purpose of this decision is to give the three IOUs authorization to plan for and procure the resources necessary to provide reliable service to their customer loads for the planning period 2005 through 2014.

2. This decision must work in concert to coordinate and incorporate Commission and legislative efforts from other proceedings, in particular: Community Choice Aggregation (CCA), Demand Response (DR), Distributed Generation (DG), Energy Efficiency (EE), Avoided Cost and Long-term Policy for Expiring Qualifying Facility (QF) Contracts, Renewables Portfolio Standard (RPS), Transmission Assessment and Transmission Planning. This decision must also incorporate the Commission's direction, articulated in D.04-10-035, the Resource Adequacy (RA) decision in this docket.

3. Since the EAP was adopted, we have directed the utilities to prioritize their resource procurements following the loading order of preferred resources established in the EAP. The EAP's loading order framework identifies certain demand-side resources as preferred because they work towards optimizing energy conservation and resource efficiency while reducing per capita demand, as well as certain preferred supply-side resources. The EAP loading order is: energy efficiency (EE) and demand response (DR), renewables (including renewable distributed generation), clean fossil-fueled distributed generation (DG) and clean fossil-fueled central-station generation. Sensible transmission investments should be made in concert with these other resource choices.

4. After existing resources and policy preferred resources have been compared to load and necessary reserves, the result is the amount of energy and capacity which a Load Serving Entity must still acquire. This is called either

"need" or the "net open" position, sometimes subdivided into "net short" and "net long."

5. The Assigned Commissioner appropriately directed the IOUs to file LTPPs based on 3 scenarios:

a) The medium-load plan is the preferred resource plan of each utility that meets the needs identified in its Alternative Base Case load-forecast scenario or, if the utility does not choose to file an Alternative Base Case load-forecast scenario, its IEPR-CEC base case scenario;

b) The high-load plan is a reasonable guess at how great the burden of service could become under high, but not unreasonable assumptions about future load growth, and should be based on the assumption of greater than expected economic growth, resulting in higher load growth, assumption of a modest core-noncore load loss and a modest development of CCA beginning in 2009, and assuming that current levels of DA will continue throughout the time horizon; and

c) The Low-Load Plan is based on reasonable but pessimistic assumptions about the economy and assumes aggressive CCA development beginning in 2006, and an aggressive core-noncore scenario, as well as the continuation of DA service at current levels.

6. The purpose of the three resource scenarios is to assist the Commission in understanding how each utility intends to respond to a wide range of load scenarios; the focus is not on forecasts, but on the adoption of long-term plans that can accommodate many outcomes.

7. Although all three IOUs relied on different assumptions in modeling their medium case and in setting floors and ceilings for the high and low scenarios, for the most part the three LTPPs complied with the resource scenario request. The differing assumptions made cross-utility comparisons difficult, but each LTPP taken on its own provided a reasonable range of scenarios as boundaries of risk.

8. The “service area” or “reference” forecasts presented by the IOUs in their LTPPs indicate reasonable growth trends and levels. The utilities use similar growth factors and are generally consistent with the IEPR forecast trends, except the levels are higher because they are updated from a 2001 baseline to a 2003 baseline. This update reflects the unanticipated economy recovery in 2002 and 2003 that was not reflected in the IEPR forecast.

9. Since CCA has been set in statute and is the subject of an on-going CPUC implementation proceeding, it is reasonable to assume that some CCA will start to occur in 2006. There was not sufficient evidence in this proceeding to prove that CCA alone will have a material effect on IOU resource needs in the next few years.

10. A major issue in this proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligations to provide reliable service to their customers. The implementation of CCA, departing municipal load, and the potential for lifting, in some form or another, the current ban on allowing new direct access, all create uncertainty as to the amount of load the existing utilities will be responsible for serving in the future.

11. Existing resource planning uses average weather (1-in-2) and then adds a reserve margin which, in part, provides the cushion should hotter than average weather occur. This is the approach we adopted to implement our resource adequacy requirements and should also be applied here.

12. We provide guidance on resource planning based on the EAP and current circumstances, but only market-tested bids will actually produce a portfolio of specific resources. In this setting, planning is largely indicative, not deterministic.

13. Approving a mixed portfolio of different contract terms and lengths will help to ensure that the utilities will not over-subscribe to long-term contracts that will crowd out future opportunities.

14. All three IOUs have capacity needs throughout the planning horizon. Capacity needs expand considerably in 2011, due to the expiration of most of the DWR contracts. All three IOUs are long on energy, primarily in the off-peak and shoulder hours, through 2009 (PG&E) and 2010 (SCE and SDG&E) until the bulk of DWR contracts expire. Because resources are 'lumpy', adding preferred resources upon existing resources somewhat exacerbates this long position, requiring utilities to be energy sellers in many off-peak and shoulder hours.

15. We must balance grid reliability with our other primary public duty of protecting ratepayers from excessive charges and also be mindful of potential departing loads and stranded costs.

16. The IOUs complied sufficiently with Commission direction in preparing their resource scenarios so we will not require the preparation and resubmission of LTPPs at this time. Any deficiencies in the LTPPs can be addressed by requesting updates as the Commission gives new direction or clarification in other resource/procurement proceedings and can direct us in giving guidance for the next LTPP proceeding.

17. Because there is no way to predict the energy demand/supply situation with any certainty, especially in the face of changing load situations, the IOUs should include a mix of resources, fuel types, contract terms and types, with some baseload, peaking, shaping and intermediate capacity, with a healthy margin of built-in flexibility and sufficient resource adequacy in their procurement portfolios.

18. The IOUs must have sufficient flexibility in their plans to procure resources as directed by the Commission in the areas of EE, DR, DG, renewables, and soon QFs. The IOUs must balance expiring DWR contracts with meeting required targets in EE, DR and renewable generation.

19. We find that PG&E's LTPP plan is reasonable and we approve PG&E's strategy of adding 1,200 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 resource adequacy obligations. 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.

20. We find that SCE's LTPP resource plan is reasonable, subject to the compliance requirements covering its demand forecast, demand response, energy efficiency, QFs, 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 such a case to the Commission as an implementation of its LTPP by way of an application following a RFP.

21. SDG&E's resource scenarios were the most complete and useful in understanding the impact of differing loads, risk strategies, and the complex process of compiling a portfolio that meets reliability, adequacy, policy preferences and cost moderation goals.

22. We find that SDG&E's resource plan is reasonable, subject to the modifications required for the compliance filing described herein. SDG&E is essentially fully resourced through 2009, other than needed investments in renewable resources to meet RPS targets.

23. We find that the IOU filings comply with the direction provided in the EAP because they included the EAP targets established in the RPS, DR and EE proceedings; included, at a minimum, the DG forecasts in the 2003 IEPR, and added transmission and clean central-station generation to meet remaining energy and capacity needs.

24. We concur with the CAISO that the transmission elements of the plans were insufficient to meet our goals and accept their recommendations that future plans should include conceptual scenarios that illustrate the impact of potential generator location.

25. When an IOU proposes a major transmission line, it should include a companion scenario without the line. Pursuant to the September 16, 2004 ACR issued in this proceeding, these resource scenarios will be examined in the Energy Commission's 2005 IEPR. To the extent an IOU believes that the range of need identified in the 2005 IEPR is sufficient to justify a transmission project then it may be identified as a specific proposal to satisfy need in the 2006 procurement proceeding filings.

26. Utilities should update their gas price forecasts in future LTPPs using the criteria set forth in D.04-01-050 and the June 4, 2004 ACR.

27. Potential community choice aggregators raised policy issues centered on how the IOUs should plan prospectively and judiciously for upcoming CCAs, or other departing loads, so that there would not be excess energy if, or when, the CCAs became fully functional and able to serve customers previously served by one of the IOUs.

28. The threshold policy issue underlying cost responsibility surcharges is to ensure that remaining bundled ratepayers remain indifferent to stranded costs left by the departing customers.

29. We will not determine a precise trigger point when an IOU can stop procuring for a CCA in this decision. Instead, we encourage cities and counties that are seriously considering CCA to approach their IOU and proactively consider strategies in which the two parties can share procurement risk going forward. Such strategies could include agreements between the IOU and CCA to allocate certain contracts to the CCA once it is formed. A CCA may execute a binding notice of intent with a commitment to a target date, at which the CCA is responsible its own energy procurement and resource adequacy. If the CCA does so, its customers will not be responsible for stranded costs of any utility commitments entered into after the agreed upon date. However, if the CCA does not meet the target date, it will be liable for any incremental costs that the utility incurs in excess of its average portfolio cost to serve the load that the CCA is not able to serve. We support parties working together to seek the most efficient transaction between the IOU and CCA.

30. Given the potential for a significant portion of the utilities' load to take service from a different provider, the utilities are concerned that they could end up over-procuring resources and incurring the stranded costs associated with these resources.

31. In D.04-01-050, we stated that a flexible utility portfolio, consisting of a mix of short-, mid- and long-term resources would be the best mechanism to protect against utility over-procurement. Since the issuance of that decision, we have made the utilities responsible for ensuring local reliability, accelerated the resource adequacy requirement from 2008 to 2006, and adopted RPS target goals resulting in the solicitation of new renewable energy sources by the utilities. These initiatives, combined with the existing overhang of utility retained generation and long-term DWR contracts significantly limit the flexibility that the utilities have to quickly adjust their resource portfolios. All of these resource additions benefit all existing customers by improving reliability and promoting renewable energy development.

32. We recognize a potential mismatch between the types of resources that the utilities need to procure (primarily peaking and load following) and the resources that departing customers require (primarily base load with a lesser amount of peaking/load following capability). Thus it may not be possible for the utility to develop a resource portfolio that accurately matches the load profile of expected departing load.

33. In general we agree that the utilities should be allowed to recover their net stranded costs from all customers, which may require the application of additional cost responsibility surcharges or other non-bypassable surcharges.

34. Providing for stranded cost recovery provides a greater incentive for the utilities to enter into longer (3 to 5 year) contracts for existing capacity that many parties advocate as the optimal approach to ensure the availability of these resources.

35. The utilities may need to enter into new contracts or construct new capacity to ensure that California has sufficient resources toward the latter years

of this decade. In order for these resources to be on-line when needed, it may be necessary to begin construction of these projects in the very near term, since the record demonstrates that new construction would require a minimum ten-year contractual commitment. In the near-term, it appears that the utilities are the only entities capable of financing these projects.

36. New renewable projects, necessary for the achievement of the EAP and legislative goals, also require long-term commitments in the range of 10 to 20 years.

37. The utilities should be allowed to recover the net uneconomic costs of these commitments. Similar to the treatment of DWR energy commitments, the utilities should take appropriate steps to minimize the costs by selling excess energy and capacity needs into the marketplace. These other revenue sources include market sales, sales into the CAISO's energy / ancillary services market, and potential sales into capacity markets, should they develop. All revenue sources should be credited against the utilities costs.

38. Development of liquid and competitive capacity markets may reduce the risk of capacity investment in the face of potential customer migration. They may facilitate the reduction and mitigation of stranded costs.

39. Demand response programs can be used to help achieve both system efficiency and reliability goals. There are two general types of demand response programs that the IOUs use to reduce demand when energy prices are high or when supplies are tight: 'price-responsive' programs (in which customers choose how much load reduction they can provide based on either the electricity price or a per-kW or kWh load reduction incentive), and emergency-triggered programs (in which customers agree to reduce their load to some contractually-determined level in exchange for an incentive, usually a commodity discount).

40. Both types of demand response programs should be designed to motivate customers to reduce their loads in exchange for some type of benefit, such as reduced energy rates, bill credits or exemptions from rotating outages. As used in this decision, the term ‘demand response program’ means ‘price-responsive’ programs for which the Commission has established specific MW targets to be incorporated into the IOU’s LT procurement plans.

41. D.03-06-032 adopted price-responsive programs, set target goals and directed the utilities on how to integrate demand response goals into their procurement plans. As of July 2004, the IOUs have a combined total of 519 MWs enrolled in the authorized programs. D.03-06-032 also adopted demand response goals for years 2003 – 2007. The 2005 goal is 3% of ‘annual system peak demand’, increasing to 4% in 2006 and 5% in 2007. The adopted goals apply only to ‘price-responsive’ demand response programs. MW savings generated by interruptible programs do not count toward the demand response goals articulated in the Energy Action Plan. Enrollment in interruptible programs is capped at 2,500 MW.

42. It is clear that the utilities have used inconsistent definitions of annual system peak in arriving at their MW targets for price-responsive demand. For each utility, the “annual system peak” should be the annual system peak for their respective service territories, inclusive of all customers taking service within those boundaries

43. It is too early to judge whether or not the current demand response goals are achievable. Rather than adjust them now or institute an annual review/adjustment process as suggested by the IOUs, the Commission will retain the current 3% of annual system peak goal and further encourage the IOUs to continue with their best efforts in reaching them. Cost-effectiveness of

demand response programs is also important to the Commission, and future demand response proposals will be evaluated for their cost-effectiveness in the demand response rulemaking (R.02-06-001) or its successor.

44. The Commission's efforts in the area of DG have focused on promoting customer-side DG installations in utility service territories. These efforts are directed in four areas: Financial Incentives – rebates are offered to customers installing DG through the Self-Generation Program & CEC's Emerging Renewables Technology program; Interconnection Rules -- streamlining interconnection regulations and processes through the Rule 21 Working Group; Special Tariffs and Exemptions -- such as the standby charge exemptions for certain DG in accordance with PU Code Sections 353.1 and 353.2 and the Departing Load Cost Responsibility Surcharge exemptions from D. 03-04-030; and Net Metering – the PUC expanded net metering eligibility to include biogas digester and fuel cell projects along with the currently-eligible solar and wind projects.

45. In addition to promoting customer-side DG, the Commission is also pursuing grid-side initiatives. In accordance with D.03-02-068, the three IOUs are required to evaluate DG as an alternative to distribution system upgrades, subject to a prescribed set of conditions enumerated in the decision. As of the effective date of this decision, none of the utilities have yet issued RFOs identifying projects where DG might serve as an appropriate alternative.

46. The DG rulemaking's progress towards developing a cost-benefit analysis methodology for DG will inform future policy guidance we provide to the utilities regarding DG as a procurement resource.

47. The utilities appropriately reflected the Commission's preferred loading order by including energy efficiency savings targets in their LTPPs as the priority

procurement resource. Since the IOUs filed their LTPPs on July 9, 2004, the Commission issued D.04-09-060 on September 23, 2004. D.04-09-060 translated into a numeric goal the mandate from the EAP to reduce energy use per capita. For the electric IOUs the adopted savings goals reflect the expectation that energy efficiency efforts in their combined service territories should be able to capture on the order of 70% of the economic potential and 90% of the maximum achievable potential for electric energy savings over the 10-year period covered by the LTPPs.

48. As discussed in this decision, any incremental investments in energy efficiency over and above the PGC funding needed to achieve the Commission adopted energy savings targets will be considered in R.01-08-028 and related ratesetting dockets for energy efficiency funding that we may initiate.

49. SCE proposed to add a 1% reliability factor to downgrade program savings from non-utility energy efficiency programs operating in its territory. SCE asserted that this reliability factor would address the uncertainty in the timing and magnitude of savings from non-utility programs until rigorous evaluation, measurement and verification (EM&V) of these programs becomes available. We reject SCE's proposal and reiterate our prior directive in D.04-01-050 for the utilities to count expected energy savings from non-utility programs that operate in their service territories.

50. Energy efficiency issues such as the program administrative structure, program funding cycle and duration, funding levels and program portfolios, EM&V framework and protocols, performance incentives, fund shifting authority, and avoided costs used in cost effectiveness calculations will be considered in the energy efficiency rulemaking (R.01-08-028) and not in this proceeding. The Commission has also instituted R.04-04-025 to address avoided

cost issues pertinent to energy efficiency programs and other resource applications. We will continue to coordinate these various proceedings to the extent that our decisions in those proceedings impact the utilities' LTPPs.

51. QFs whose contracts expire after December 31, 2005 are not eligible for the one-year or five-year contract extension options set forth in D.03-12-062 and D.04-01-050, respectively. Currently, the only recourse for QFs, whose contracts expire in 2006 and beyond, is (1) to participate in any upcoming power solicitations, or (2) negotiate bilateral contracts with utilities. Neither of these two options is entirely certain. We recognize that without contract extensions or a new long-term policy, QF contracts that lapse in 2006 could cause QF power to go off-line at that time; however, our plan to address these issues by mid-2005 will avert these concerns.

52. On August 8th, 2003 the Commission established via Assigned Commissioner's Ruling the interim guidelines for renewable energy procurement prior to full implementation of the RPS program. In the intervening 16 months the RPS program has been fully established as the central mechanism guiding renewable resource development.

53. In general, IOUs must procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and will be allowed to credit this procurement towards their Renewables Portfolio Standards (RPS) targets. If an IOU succeeds in procuring sufficient renewable resources to meet its RPS Annual Procurement Target (APT) via an all-source RFO, it will not be required to undertake an RPS-specific solicitation.

54. We agree that the renewable procurement sections in SCE's and PG&E's LTPPs are inadequate and need revision. The revisions, with a detailed analysis, will be developed in the IOUs' 2005 RPS procurement plans, which will be filed

in R.04-04-026, incorporating additional guidance to be developed in that docket, and with full access to the record in this proceeding. The IOUs must provide detailed annual analysis of renewable resource potential over the next 10 years in their 2006 LTPPs and must include transmission planning for renewable resources in their 2006 LTPPs. Transmission issues will be further addressed in I.00-11-001, in coordination with the RPS docket.

55. We find that RPS targets are a floor – not a ceiling. The EAP loading order places renewables above conventional generation.

56. Using unbundled RECs for RPS compliance is complex and the record here is insufficient; therefore, it is premature to make a determination on this policy at this time. We will consider this issue in R.04-04-026 as appropriate.

57. We recognize that the IOUs' LTPPs did not fully, or adequately, integrate generation and transmission system planning. On October 15, 2004, the Assigned Commissioner in R.04-01-026, the Transmission Assessment OIR, issued a ruling stating "To achieve a comprehensive resource planning framework, the Commission must streamline the transmission planning process and integrate that with the biennial procurement process." The legislature has enacted and the Governor has signed SB 1565 directing the CEC to develop a strategic transmission plan.

58. The purpose of R.04-01-026, issued January 24, 2004, is to streamline the transmission planning process for the IOUs by eliminating the duplicative transmission need assessments that currently exist at the CAISO and the Commission. A component of this streamlining is the Commission's proposed deference to need determinations made in the CAISO's grid planning processes.

59. I.00-11-001 was undertaken for the implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints,

actions to resolve those constraints, and related matters affecting the reliability of electric supply.

60. The present procedure for transmission expansion and upgrades is for the IOUs to prepare annually a grid expansion plan, which looks five and ten years into the future. The plans forecast growth in load, the connection of new generation, the retirement of plants whose service lives have come to an end, new transmission facilities and interconnections with adjacent and out-of-state networks. The plans are the product of several iterations of work by engineers followed by stakeholder meetings at which preliminary results are presented and commented upon by the stakeholders. This is an open process in which the Commission staff participates. The plans are then finalized for the year and submitted to the CAISO for review. The CAISO approves, modifies or rejects individual projects. Projects costing up to $20 million are approved by CAISO staff and projects whose cost is greater than that amount require approval of the CAISO Board of Governors. The CAISO also participates directly in the planning of transmission between utilities and, in particular, transmission interconnections with other states.

61. LTPPs should more fully integrate generation and transmission planning. It would be helpful to the Commission's review of the LTPPs if they included scenarios of potential resource portfolios to fully meet future resource needs, and identified the transmission expected to be needed to make the potential resource portfolios feasible. It is not acceptable for IOUs to take the position of only responding to interconnection requests, as SCE proposes. We will work with the CEC to provide guidance for LSE filings in the 2005 IEPR proceeding so that progress toward integration may be made.

62. Phase 2 of the RA portion of this proceeding is scheduled to adopt procedures that will allow identification of “year-ahead” local capacity requirements and overall deliverability for resource adequacy in the early summer of 2005. Those analytic procedures that identify local capacity requirements will inform and govern the utility transmission and procurement requirements going forward.

63. It is premature to address specific requirements regarding local capacity and deliverability in this proceeding or make a judgment as to the sufficiency of the instant filings. However, it is important to provide clarity on how the local capacity and deliverability requirements will come into play in future planning decisions.

64. We expect that the CAISO will work closely with the Commission to establish the analytic procedures that identify local capacity procurement requirements based on deliverability of resources into load pockets and transmission constrained areas of the grid. We expect that once established, the CAISO will work to update the criteria as changes, such as new transmission or generation, occur that alter these local needs as deliverability constraints evolve.

65. In the next few years, IOUs could add extensive new generation to their resource portfolios in order to meet their future resource needs. We believe a ratemaking mechanism needs to be in place to ensure proper and timely cost recovery for these facilities.

66. Cost recovery should begin when the new facility starts operation to serve utility customers.

67. We adopt SDG&E’s proposal for cost recovery framework for turnkey projects. Each utility should establish rate-base and O&M-related revenue requirements associated with the generation plant and should use its Non-Fuel

Generation Balancing Account (NGBA) and Energy Resource Recovery Account (EERA) to record costs associate with the turnkey plants and for recovery through each utility's commodity rates.

68. Planning and administrative costs of preparing for the construction or acquisition of the generation facilities, financing costs as incurred, and costs if the project is ultimately abandoned will be considered in our review and evaluation of IOU contracts for turnkey projects and may be considered as part of establishing the revenue requirement for these facilities. Therefore, these types of costs should not receive special recovery treatment and PG&E's proposed approach should be rejected.

69. The current ERRA trigger mechanism requires the Commission to adjust procurement rates if the ERRA balancing account becomes undercollected or overcollected by more than 5% of the previous year's non-DWR generation revenues. This trigger mechanism is set to expire on January 1, 2006.

70. We find that the ERRA trigger provides the IOUs assurance that procurement costs will be recovered in a timely fashion, and we keep the trigger in effect during the term of the long-term contracts, or ten years, whichever is longer.

71. The current disallowance cap is applicable to contract administration and dispatch from the integrated DWR-IOU portfolio. The cap amount is equal to two times the utility's costs of procurement function. In D.03-06-067 the Commission ruled that SCE's request to expand the disallowance cap established in D.02-12-074 to include all procurement activities violates the legislative mandate of Assembly Bill 57, as codified in Pub. Util. Code § 454.5, as well as Sections 451 and 702.

72. PG&E requests that the disallowance cap apply to all utility dispatch, including URG, PPAs, and allocated DWR contracts on the grounds that this would provide certainty in estimating the potential financial risk utilities face. Consistent with our determination in D.03-06-067, as discussed above, that an extension of the disallowance cap violates legislative intent and the statutes, we reject PG&E's request. In its Petition to Modify (PTM) D.03-12-062, filed February 20, 2004, PG&E asks the Commission to clarify that for purposes of upfront standards for procurement transactions, "short term" means up to and including 3 calendar months, or one quarter, not "90 days." PG&E also wants a clarification that the IOUs can conduct competitive solicitations in an auction format. PG&E argues that the use of online auction techniques for competitive procurement falls within the guidelines presented in D.03-12-062 and D.04-01-050.

73. We clarify that D.03-12-062 authorized IOUs to conduct procurement using negotiated bilateral agreements for transactions of up to three calendar months, or one quarter, forward; and that utilities will consult with their PRGs for transactions with delivery periods of greater than three calendar months, or one quarter. We further clarify that D.03-12-062 authorized IOUs to conduct procurement using an electronic auction format for execution of competitive solicitations, among other transactional methods. The authorized products are good for short-, medium-, and long-term procurement.

74. On February 19, 2004, SCE filed a Petition for Modification (PFM) of D.03-12-062 (the 2004 Short Term Procurement Plan Decision). SCE's PFM presented argument on twelve separate issues in the D.03-12-062 that, SCE contends, affect its ability to procure power and make it difficult for SCE to

comply with portions of the decision as it is written. SCE's list of twelve requested modifications are set forth in its LTPP, Vol.2, p.13-16.

75. We grant ten of SCE's twelve requested modifications with the exception of modifications seven and nine. Thus, we deny the PTM regarding modification of language that would require an "unqualified certification" as a basis for authorizing SCE's proprietary risk model. We deny the request to eliminate the requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges.

76. It is likely that greenhouse gas emissions will be regulated within the timeframe addressed in the utilities' LTPPs and the lifetime of the utilities' long-term resource commitments.

77. Greenhouse gas emissions pose a real and substantial financial risk to customers and the utilities.

78. The Commission should require the utilities to explicitly assess and mitigate the financial risk from greenhouse gas emissions in procurement and in future LTPPs.

79. Consistent with established Commission policy~~,~~ and the positions of several parties, including PG&E, we adopt a range of values to explicitly account for the financial risk associated with greenhouse gas emissions (which we call a "GHG adder"), of $8 to $25 per ton of CO_2, to be used in the evaluation of generation bids. This range is taken from information in the present record. Each IOU will select a value within the adopted range and respond to party comment on the value, before employing the adder in analyzing RFO responses.

80. The GHG value will be added to the prices bid in future procurement, and will be used to develop a more accurate price comparison between and among fossil, renewable and demand-side bids. In the event that the fossil bid is

ultimately selected, the adder will not be paid to that generator or charged to ratepayers; it is an analytic tool only.

81. It is anticipated that the Commission will adopt a fixed value for GHG emissions (not simply a range) in approximately March 2005 in the Avoided Cost Rulemaking (R.04-04-025). Once adopted, the IOUs will use that value when analyzing bids. Additionally, the IOUs will use the value adopted in R.04-04-025 in their next LTPPs when modeling alternative resource portfolios and selecting a preferred portfolio**.**

82. The California utilities are moving forward in a new hybrid market structure supported in large part by this Commission. Since the crisis, the Commission has authorized, and the utilities have conducted, a number of all-source and renewable power solicitations that have successfully procured thousands of megawatts of power under short- and long-term contract to serve California customers.

83. Our most recent experience with procurement solicitations was the SDG&E Grid Reliability RFP process that involved head-to-head competition among both supply-side and demand-side resources (megawatts and negawatts), peaking and baseload resources, an affiliate resource, renewable generators, a merchant PPA, and utility turn-key power plants. This was our first experience with such diversified head-to-head competition among competing resource types, yet it was a successful undertaking.

84. We have determined that it is time to allow greater head-to-head competition and hereby lift the affiliate ban on long-term power products. Accordingly, we adopt certain guidelines and safeguards, including an independent third party evaluator requirement. We will allow the consideration of debt equivalence in the bid evaluation process as specified herein, and we will

also require the use of a GHG adder as a bid evaluation component. With these policies we continue to shape and define the hybrid power market in California so as to advance the positive benefits of competition, and deliver California's energy services according to the priorities of state policy.

85. While the Commission has stated a preference for a hybrid wholesale electric market consisting of PPAs and IOU owned resources, this should not undermine the Commission's goal of having the IOUs acquire supply-side resources based on LCBF principles, regardless of ownership form.

86. We are not persuaded by SCE's argument that D.04-01-050 precludes the IOUs from doing an all-source open RFO because a bid evaluation methodology doesn't exist. The IOUs will employ the LCBF methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative[167] attributes associated with each bid. In addition, when seeking Commission approval for the proposed contracts the IOUs will need to demonstrate that they employed LCBF principles. It is expected that the Commission will revisit the LCBF methodology, integrating "lessons learned" from future all-source open RFOs.

87. We agree with Calpine that, "Putting shareholders – not ratepayers – at risk for cost overruns will put IOU-owned projects and PPAs on equal footing (at least with respect to the allocation of risk), impose some measure of market discipline on IOUs when formulating their bids, and better ensure that the

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[167] Qualitative and quantitative attributes such as performance risk, credit risk, price diversity (10 vs. 20 yr. price terms), and operational flexibility etc.

resource solicitation process is fair and competitive."[168] Consequently, IOUs will not be allowed to recover initial capital costs in excess of its final bid price for utility-owned resources.

88. 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 (i.e., IOU-built, turnkeys, buyouts, and PPAs do not need to participate in every all-source and RPS solicitation).

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[168] Calpine opening brief, pp. 12

89. Bids should reflect total cost (generation and transmission) of delivery to load. In addition, bids from Utility-owned generation (IOU-build, turnkey, and buyouts) will be capped at initial capital costs. If actual costs come in under the capped bid, then there should be a 50/50 sharing of savings between ratepayers and utilities. Lastly, utility-owned resources that are selected in a solicitation will be eligible for Cost-of-Service ratemaking (future plant additions, annual O&M expenses etc.).

90. Utility-built resources that are selected in a solicitation will file a CPCN with the Commission. Solicitation - CPCN process: CPCN process incorporates need determination, cost caps, and CEQA review. Having said that, bid cap would come from the RFO process, need determination would come from the approval of the Long Term Procurement Plan. The only issue left to be addressed in the CPCN is the CEQA review.

91. If an IOU considers the bids from a particular solicitation too high they have the right to terminate the solicitation. However, the IOU will need to reissue another solicitation if they want to file a CPCN with the Commission. They will not be allowed to file a CPCN for a project unless it was selected in a solicitation.

92. FERC has recently set forth Guidelines for Reviewing Future Section 203 Affiliate Transactions, which include guidelines for IEs in 108 FERC 61,081 (July 29, 2004). FERC explained that to the extent to which a utility demonstrates that its RFP process follows the stated guidelines, its application processing time (including litigation) will likely be reduced, thus increasing the possibility of more timely Commission approval through an adequate showing under the Edgar standard.

93. The FERC guidelines provide for substantial IE involvement in resource solicitations at the "design, administration, and evaluation stages of the competitive solicitation process." FERC has set forth "minimum standards for assuring independence and the scope of the third party's role."

94. We acknowledge the detailed IE guidelines set forth by FERC in its recent July 2004 and generally endorse them. At this time, we will outline an interim approach, which we may refine at a later date based on our further experience in this area. We determine here that we will not allow the IEs to make binding decisions on behalf of the utilities. We will require the use of an IE in resource solicitations where there are affiliates, IOU-built, or IOU-turnkey bidders. However, we will not require that the IEs administer the entire RFO process. The IOU shall consult with its IE and PRG on the design, administration, and evaluation aspects of the RFO to ensure that the overall scope is not unnecessarily broad or otherwise too narrow. IEs should be available to testify as an expert witness in any associated Commission proceeding regarding upfront review of potential solicitation transactions.

95. IEs should come equipped with technical expertise germane to evaluating resource solicitation power products. In the case of an affiliate/IOU-turn key power plant, IEs should be able to quickly scrutinize, examine, and essentially break down bids to determine whether the various cost components are reasonable as presented. IEs should be skilled in analyzing a range of power market derivatives (e.g., futures, contracts, options, swaps). IEs should be familiar with the various standard contracts and industry practices. IEs should have experience analyzing the relative merits of various types of PPAs. IEs should be able to evaluate PPAs, turn-keys, and IOU-builts on a side-by-side

basis. An IE should make periodic presentations regarding their findings to the IOU and to the PRG.

96. Cost overruns associated with utility-owned resources should be borne by shareholders, because this approach will level the playing field for IOU-owned projects and PPAs, with respect to risk allocation. Cost Savings should be shared 50/50 with ratepayers and shareholders.

97. The IOUs have shown that rating agencies employ various methodologies to assign debt equivalence on their balance sheets for power purchase agreements.

98. Standard & Poor's (S&P) has the most robust methodology for calculating debt equivalence, but their 30% risk factor is based on subjective criteria that should be adjusted downward. So it is reasonable to adopt a 20% risk factor to be used by the IOUs in evaluating PPAs.

99. The arguments presented by SDG&E that keeping Sunrise in its plan reduces its option to address local reliability issues and ORA's proposal that SCE contract with SDG&E for dispatch rights for specific units under the DWR-Williams contract, will be addressed either in the next phase of RA, or in the DWR contract proceeding.

100. In the short- to mid-term, RMR and contracts should suffice to keep the aging plants in operation. These plants could bid into RFOs and because of their advantage over new plants, such as proximity to load centers and infrastructure, they should be competitive in their bids.

101. To the extent feasible, old plants should be retrofitted, and refurbished. It is generally good policy to consider using brownfields first instead of using greenfields, because of existing infrastructure, being close to load centers, and other benefits.

102. While we expect RA Phase II to resolve local reliability, in the interim we extend the requirements of D.04-07-028. In particular, the policy requirements of D.04-07-028 and any implementation procedures should be handled by IOUs filing Advice Letters until local reliability is resolved in RA Phase II, or by other action of this Commission.

103. SDG&E is a unique case among the three IOUs in that within service area resource additions almost certainly will provide local reliability benefits, unlike SCE or PG&E. We therefore direct SDG&E to pursue the EAP loading order priorities when it makes resource additions.

104. The three utilities have presented information on the processes they undertake to develop bottom-up forecasts of their needs and of the plans to deal with those needs. We are satisfied that the utilities are complying with our orders and taking into account the needs of local areas within their service areas in developing their plans.

105. We endorse the coordination agreement and the direction to IOUs stated in the September 16, 2004 ACR. We direct IOUs to participate in the CEC IEPR proceeding as the one forum in which long-term load forecasts, resource assessments, and need determinations will be considered. We believe Appendix B constitutes a good foundation for coordinated proceedings and the minimization of duplication between various planning proceedings. We direct staff to work with the CEC and CAISO to effectuate this agreement in a complete and practical manner.

106. We find that no change is necessary at this time for the Semiannual ERRA Application. As for the Short-Term Procurement Plan, the 2006 Long-Term Procurement Plans will contain the features of the Short-Term Plans that are not covered by the proposed 2004 LTPPs. That is, ultimately, we will eliminate the

STPPs and the IOUs will act in accordance with a single Commission-approved plan. Until then, the existing STPPs will be in effect. Updates or modifications to the plans in between the biennial review will be filed with an advice letter. Any updates to the existing STPPs should be filed with an Advice Letter 30 days after the issuance of this decision.

107. No change is necessary at this time to the semi-annual gas supply plans and biennial LTTPs.

108. If an increase to SCE's collateral capacity is required to carry out the LTTP approved by the Commission, SCE will provide updated collateral estimates. No party has taken issue with SCE on this issue. Accordingly, we accept SCE's stated approach.

109. We also note here that SCE can, and does, require counterparties to make similar collateral postings aimed at ensuring contract performance under changing market conditions. We are not aware of any specific claims of over-collateralization or associated recommendations.

110. SCE has informed the Commission of two relatively new accounting rules promulgated by the Financial Accounting Standards Board (FASB) "that, like the debt equivalence issue, may affect electric utilities' costs of contracting for power. While SCE has not requested any specific relief related to these new accounting rules, SCE may seek further guidance from the Commission when appropriate in the same manner as set forth in the Cost of Capital proceeding.

111. Consistent with the Commission's direction in D.04-01-050, it is our intention that many more categories of planning information will be open to the public and will be considered so in our review of the IOU's LTPPs. We have yet to determine if any information that routinely was considered confidential under former protocols might be deemed public when this decision is issued in final.

112. We must balance the competing interests of the need of some confidentiality of IOU data to protect ratepayers, against the public interest in disclosure and the desire of intervenors to have better access to IOU confidential data to more fully participate in Commission proceedings. While we move closer to "open decision-making" we need to be pragmatic about mitigating any adverse ratepayer consequences.

113. Currently under AB 57, that added Section 454.5 to the Pub. Util. Code, the Commission is to have in place procedures that ensure the confidentiality of any market sensitive information submitted by an IOU as part of its proposed procurement plan, while ORA and other consumer groups that are not market participants (NMP) access to the information under confidentiality provisions. This provision of AB 57 was an attempt to balance the compelling ratepayer interest in ensuring that certain legitimately confidential information is kept out of the hands of those who can use it to manipulate wholesale energy markets, with promoting a sufficiently transparent decision-making process to allow for scrutiny and review by the legislature and the public.

114. Following a request from SDG&E to amend the April 4, 2003, ALJ ruling to protect information submitted by parties to a RFP, the ALJ issued a ruling on December 1, 2003, amending the previous protective order allowing certain bid information to remain confidential, but also soliciting comments on a further modification to the protective order to incorporate a provision allowing outside attorneys and/or consultants to a MP who do not perform competitive duties for or on behalf of their client, and who execute a Non-Disclosure Certificate, to have access to materials relevant to the SDG&E RFP. On January 14, 2004, following the receipt of comments on the FERC model, the ALJ issued a ruling adopting an Amended Protective Order that was substantially consistent with the FERC

orders and that allowed the MPs access to Protected Materials following the FERC guidelines. As referenced earlier in this decision, this Amended Protective Order controlled confidentiality issues in this current procurement proceeding.

115. In preparation for review of the IOUs' LTPPs in this proceeding, in D.04-01-050 the Commission expressed its desire to move towards more open and transparent decision making and asked the parties to submit comments on how to allow more access to utility data, but not at the expense of the ratepayer/consumer. Comments were received on March 1, 2004. By that time SB1488 was already in committee, so instead of issuing a new iteration of the January 14, 2004, Amended Protective Order we followed the guidelines implemented therein for this procurement proceeding.

116. We also note that more intervenors, in particular the environmental groups, had access to the IOUs confidential data since they signed on to the Amended Protective Order. So in addition to the consumer groups, other NMP also had the benefit of reviewing all the utility data. None of the MPs chose to sign on to the Amended Protective Order. The utilities and the MPs may have reached a point of equilibrium in that if the MPs had more access to utility information, the utilities may have demanded equal access to MP information.

117. SOS may be a useful mechanism for wholesale procurement by LSEs, and it may be appropriate for California once it is further developed and considered. SOS is substantially different from the procurement methods currently being used by the IOUs, and we do not have the knowledge or confidence to mandate SOS at the present time or on the basis of the current record. This topic should be further developed by participants in the second generation of topics for the RAR process, for it is a companion to another topic to be considered, the development of markets for trading capacity.

Conclusions of Law

1. We must incorporate the demand uncertainty factors into our consideration of the LTPPs and consider this uncertainty in determining the level of acquisition and the need for flexibility in the resource plans. Based on this uncertainty, we will not adopt a fixed assumption regarding the level of departing load. We acknowledge that the IOUs face considerable load variability risk, and will set policies accordingly.

2. We will not set a procurement cap based on the low cases, since this could seriously under-resource California's service areas during the planning period. Instead, we will rely on a portfolio approach and allow justification of specific contract types as the need arises. This will allow us to balance between obtaining adequate resources and not over-procuring in the case of departing load or crowding out of preferred resources towards the end of the planning period. We will monitor the IOUs' efforts to obtain resources to meet their resource adequacy requirements on a forward-looking basis.

3. We find all three LTPPs consistent with the 2003 IEPR, are reasonable for planning purposes and that the medium, preferred case should be followed for making planning and procurement decisions.

4. The EAP contains explicit direction regarding the state's preferences for meeting identified resource needs and the IOUs are to prioritize their resource selections accordingly.

5. It is reasonable to require a compliance filing of annual energy and capacity resource accounting tables, consistent with directions on baseline load forecasts, EE, QFs and DR. We do expect the IOUs to make incremental improvements in their next round of analysis to be filed with the CEC in the 2005 IEPR process.

6. It is not our intent to provide the means by which market power could be exercised against the LSEs and, hence, against electric service customers in California. Therefore, this decision does not present information about the current net open positions of the utilities, nor do we provide the elements from which that information can be calculated. It is reasonable to provide simplified tables based on projections of future resource balance information for the years 2007-2014 after those numbers have been refreshed from their initial filing in July 2004.

7. Pursuant to the direction adopted in D.04-10-035, the current focus is on maintaining and enhancing grid reliability through accelerated reserve margin targets. When this goal is integrated with the directive from D.04-07-028 issued by the Commission this summer ordering the utilities to concentrate on near-term reliability, it is evident that the IOUs must increase and retain supply for the near future.

8. Since SDG&E's estimated reserve margins, which exceed 17% in some years during the planning period are the result of prior Commission decisions, there should be no finding of unreasonableness if they exceed 17%.

9. While we do not approve SDG&E's 500 kV transmission line here, we do acknowledge the lengthy process needed to plan, license and construct transmission, and thus encourage SDG&E to continue its planning efforts and move forward with evaluating these transmission alternatives for meeting a local resource deficiency by 2010.

10. To ensure that gas price forecasts submitted in future LTPPs remain robust, we will require that the utilities provide updated gas price forecasts using the same criteria set forth in D.04-01-050 and the June 4, 2004 ACR when subsequent long term procurement plans are filed with the Commission.

11. While we recognize that the potential CCAs want to limit the amount of cost responsibility surcharge applied to departing CCA customers for utility liabilities incurred on their behalf when the CCA customers leave utility service, Pub. Util. Code Section 366.2(h) requires that the Commission authorize community choice aggregation only if the Commission imposes a cost recovery mechanism in accordance with the law.

12. We anticipate that our decision regarding CCA will implement a program whereby cities and counties can procure energy on behalf of their communities, and will also protect those bundled ratepayers who do not have the option of transferring to a CCA from the possible cost impacts resulting from the departing customers. We expect that our CCA decision will adopt a methodology for estimating the CRS that will allow bundled customers to be indifferent to the CCA program, including a methodology for CCA customers to pay their share of the costs of DWR bonds and contracts, utility procurement contracts and other items.

13. Ensuring that utilities be allowed to recover their net stranded costs from all customers meets the Commission's goals of providing "the need for reasonable certainty of rate recovery" (as required under AB 57 and noted in the June 4th ACR) as well as best ensuring that California meets its energy needs.

14. Requiring departing customers to assume a fair share of their costs is also consistent with the Commission's policy of holding captive ratepayers harmless as required by state law.

15. Allowing the utilities to recover stranded costs from all customers who benefited is consistent with recent Commission policy with regards to new resource additions. In both the SDG&E Reliability RFP (D.04-06-011) and in the Edison Mountainview Decision (D.03-12-059) the Commission required that all

existing customers of the utility were responsible for any potential stranded costs for a period of ten-years.

16. The utilities should be allowed to recover stranded costs for their non-RPS resource commitments from departing load over either the life of the contract or 10 years, whichever is less. The ten-year recovery period should also apply to any utility-owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation. Stranded costs arising from RPS procurement activities should be collected from all customers, including departing load, over the life of the contract. The utilities should be allowed the opportunity to justify in their applications, on a case-by-case basis, the desirability of adopting a cost recovery period of longer than ten years for their non-RPS resource commitments. Cost recovery for that portion of a resource acquired by the utilities to meet local reliability needs should be recovered from all customers.

17. The Commission recognizes that by keeping demand response MW goals at their current levels there may not be, at some point, any program that is cost-effective relative to alternative supply resources. As stated above, we believe it is premature to make that judgment today. Because demand response programs are currently voluntary, the challenge of designing cost-effective programs while in pursuit of greater amounts of demand response MWs each year may very well prove to be an impossible task. If and when that point becomes evident, the Commission will need to either reduce its demand response MW goals or begin consideration of mandatory demand response programs and tariffs.

18. We find that the utilities' treatment of DG as a component of the load forecast is appropriate.

19. Consistent with D.04-09-060, PG&E, SCE and SDG&E should meet or exceed the Commission’s EE goals over the next ten years and specifically over the next EE funding cycle (2006-2008) and revise and update their plans to be in alignment with these goals. PG&E, SCE and SDG&E are to incorporate the goals from the EE decision in their LTPPs, and as these energy savings goals are updated and amended by subsequent decisions, the IOUs are to incorporate the most recently adopted energy savings goals into their plans.

20. It is reasonable to require the utilities to provide information about the energy efficiency programs in a consistent format in the utilities’ future LTPP filings, which will facilitate the Commission and parties’ analysis of the proposals.

21. Given that the RPS program is operational, it is reasonable to terminate the interim renewable procurement authority granted on August 8th, 2003, in R.01-10-024.

22. Allowing an IOU to meet its RPS Annual Procurement Target via an all-source RFO, as well as via an RPS-specific solicitation, is consistent with the Legislature’s clear intent that renewable procurement be integrated as closely as possible with general IOU procurement practices. To further this effort, we will be working over the course of the next LTPP cycle to fully imbed the RPS into long-term planning, placing renewable energy development where it belongs - central to the IOUs’ resource planning efforts. Implementation of the RPS program will continue as a high priority for this Commission, and we will continue to direct the IOUs to procure new renewables via the RPS program.

23. To further California’s goal of promoting environmentally responsible energy generation and to protect customers from the financial risk associated with likely future regulation of GHG, it is reasonable to adopt a policy that

reflects and attempts to mitigate the impact of GHG emissions in influencing global climate patterns and to direct the IOUs to employ a GHG adder when evaluating fossil generation bids and in future LTPPs. This method, which will be refined in future proceedings, will serve to internalize the significant and under-recognized cost of GHG emissions; help protect customers from the financial risk of future GHG regulation; and will continue California's leadership in addressing this important problem.

24. The coordination agreement between the CEC's IEPR and the CAISO's annual grid planning process, and outlined in the attachment to the September 16, 2004 ACR also emphasizes the need for coordination between transmission planning and resource planning.

25. Once the local procurement and deliverability criteria are established we expect that the criteria may also be useful in guiding the long-term plans going forward. We recognize the importance of the CAISO in helping to establish these criteria and so that they can be applied to the utilities' planning practices. The CAISO core expertise in the area of transmission planning and grid operations is critical to inform the CEC's planning decisions and this Commission's procurement decisions. This approach will assure that the long-term resource procurement meets the CAISO short-term grid requirements. It will also assure that the resources the utilities procure pursuant to their resource adequacy requirements meet the CAISO operational needs.

26. Since the RA phase is designed to handle the reserve margin issues we will not rewrite D.04-01-050 in this decision. If parties want further clarification on the interpretation of the 15-17% requirement they should bring it up in Phase II of the RA portion of this docket. This LTPP decision is not intended to change or modify any aspect of D.04-10-035. Any clarifications, alterations or

augmentations to D.04-10-035 will be deferred to Phase II of the RA aspect and not addressed here.

27. Pursuant to DWR's request, nothing in this decision makes changes to prior Commission decisions regarding DWR contracts, particularly D.02-12-074, the IOU-DWR Servicing Agreements, or makes any changes in ratemaking treatment of the DWR contracts.

28. D.04-01-050 continued the ban on affiliate transactions, however, our position on this issue warrants re-examination at this time.

29. Given our desire to consider all competitive options, instead of continuing the ban, and carving out exceptions for unique resources from time to time, we now find that it is in the best interest of the ratepayers and consumers to allow for a full vetting of all available resources in a RFP. We will institute appropriate safeguards for the solicitations for long-term transactions, in part through continuation of utility PRGs and through the use of independent third-party evaluators. Such safeguards can protect consumers from any anti-competitive conduct between utilities and their affiliates.

30. We should adopt a methodology for debt equivalence for IOUs to employ when evaluating competitive bids from independent providers and utilities in an all-source solicitation.

31. We should adjust the S&P methodology for debt equivalence downward to a 20% risk factor to account for the fact that the California regulatory climate is improving, and we do not wish to disadvantage PPAs unduly over utility-owned generation, particularly when it comes to renewable generation.

32. It is reasonable to not allow the IOUs to recover initial capital costs in excess of its final bid price for utility-owned resources.

33. We should adopt a policy that 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 (i.e., IOU-built, turnkeys, buyouts, and PPAs do not need to participate in every all-source and RPS solicitation).

34. It is reasonable to have all-source and RPS solicitation bids reflect total cost (generation and transmission) of delivery to load. In addition, bids from utility-owned generation (IOU-build, turnkey, and buyouts) will be capped at initial capital costs. If actual costs come in under the capped bid, then there should be a 50/50 sharing of savings between ratepayers and utilities.

35. It is reasonable for utility-owned resources, which are selected in a solicitation, to be eligible for Cost-of-Service ratemaking (future plant additions, annual O&M expenses etc.).

36. It is reasonable to direct utility-built resources, which are selected in a solicitation, to file a CPCN with the Commission.

37. It is reasonable to allow an IOU, which considers the bids from a particular solicitation too high, to terminate the solicitation. However, the IOU will need to reissue another solicitation if they want to file a CPCN with the Commission. They will not be allowed to file a CPCN for a project unless it was selected in a solicitation.

38. It is reasonable to direct the IOUs to consider the use of brownfields and take full advantage of brownfield sites before they consider building new generation on greenfield sites. If IOUs decide not to use brownfield, they must make a showing as to why they prefer greenfield sites.

39. It is reasonable to extend the IOUs' procurement on a rolling 10-year basis, given that the long-term procurement plans cover a ten-year period and they will be updated and reviewed every two years.

40. It is reasonable to require certification of SCE's proprietary risk model and to require an independent third-party verification of the internal validity of the model, aimed at ensuring that all the features of the model work as advertised, that the model is mathematically sound, and that the assumptions utilized by the model are reasonable.

41. With regard to the requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges, this is a reasonable upfront standard, consistent with AB 57. The use of transparent exchanges is one reasonable check on the competitiveness of a portion of SCE's procurement activity. We direct SCE to consult with its PRG regarding the specific implementation options that are available.

42. D.04-01-050 determined that in future cycles of the procurement process, we would link our timing to that of the CEC's Integrated Energy Policy Report. Since that proceeding operates on a biennial calendar, by statute, that means that the next long-term procurement proceeding will be in 2006. D.04-01-050 also linked the substance of the analyses we direct IOUs to file with the results of the CEC's IEPR information and analyses. In the past two years, the CEC and this Commission are collaborating to a much greater degree than ever before, and as evidence the CEC is not a party to this proceeding and its staff is assisting our own in review of IOU LTPPs and in developing resource adequacy procedures.

43. Since this OIR issued, the Legislature passed, and the Governor signed, Senate Bill (SB) 1488 that directs the Commission to "initiate a proceeding to examine its current confidentiality rules under Pub. Util. Code §§ 454.5 and 583

and the California Public Records Act to ensure that the Commission's practices under these laws provide for meaningful public participation and open decision making."

44. We will soon initiate a proceeding to fulfill our obligations under SB 1488. In that proceeding we will review the effectiveness of the PRGs. For purposes of this decision and our review of the IOUs LTPPs, we believe intervenors, including MPs, had sufficient access to the IOUs' background data and assumptions, if they chose to follow the guidelines of the January 14, 2004 Amended Protective Order to allow for a robust development of the record to satisfy us that there was a full vetting of the important issues.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall, by no later than March 25, 2005, submit a compliance filing updating their procurement plans to reflect the changes and modifications adopted in today's decision. This compliance filing, shall include, but not be limited to the following:

   a. Annual energy and capacity resource accounting tables, consistent with directions on baseline load forecasts adopted in this decision;

   b. Procurement activities undertaken by the utilities subsequent to their initial filings in this proceeding;

   c. Revised energy efficiency targets as adopted in Decision (D.) 04-09-060;

   d. Demand response programs proposed for 2005 implementation in Rulemaking (R.) 02-06-011;

   e. The effect of resource adequacy and local reliability requirements adopted respectively in D.04-10-035 and D.04-07-028;

   f. Changes occurring as a result of Commission decisions implementing Community Choice Aggregation (CCA) in R.03-10-033;

g. Revised forecasts for the price of natural gas, if necessary;

h. Status of qualifying facilities (QFs) with soon to be expiring contracts; and

i. Any other material information that affects the utilities' procurement activities.

2. The Long-Term Procurement Plans (LTPPs) filed on July 9, 2004 by PG&E, SCE, and SDG&E are approved as modified in this decision.

3. When executing procurement plans in response to this decision, PG&E, SCE, and SDG&E shall:

a. Procure the maximum amount of cost-effective energy efficiency and demand-side resources;

b. For further resource needs, procure the maximum amount of renewable generation resources via all-source Request for Offer (RFO), and be prepared to defend any selection of fossil over renewable resources; and

c. Employ the greenhouse gas (GHG) adder, described herein, when evaluating fossil generation bids.

4. 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.

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

6. We find that SDG&E's resource plan is reasonable, subject to the modifications required for the compliance filing described herein. SDG&E is essentially fully resourced through 2009, other than needed investments in renewable resources to meet RPS targets.

7. Utilities shall use the criteria set forth in D.04-01-050 and the June 4, 2004 ACR to develop gas price forecasts for future LTPPs.

8. The Commission's decision in Resource Adequacy (RA), D.04-10-035, issued October 28, 2004, among other things, established that all Load Serving Entities (LSE), including the Investor-Owned Utilities (IOUs), must have reserve margins of 15-17% by June 1, 2006. As part of meeting this reserve margin requirement, each LSE must have 90% of its next summer's requirement [May through September] fully resourced by September 30 of the year before. The decision also established a 100% forward commitment obligation for a month-ahead horizon for the entire year. The IOUs are to plan to meet all RA requirements as set forth in D.04-10-035 as they go forward with their LTPPs.

9. In future procurement plans, the IOUs shall incorporate reasonable anticipated CCA departing load. The assumption of the Commission is that the IOUs shall acknowledge potential CCA departing load and identify which city and/or county has expressed intent to pursue aggregation, including MW estimates of this departing load, in future procurement plans.

10. We adopt the 15-year standard for new fossil-fueled resources acquired by the utilities. For all other contracts, including contracts for renewable generation, the utilities should be allowed recovery over the life of the contract.

11. The utilities shall continue to adhere to the directives for reflecting DG estimates in load forecasting consistent with D.01-04-050 and D.04-10-035. We also encourage SCE to move forward with its planned DG RFO, the results of which will be monitored by the Commission for guidance in both the DG rulemaking and this docket.

12. Consistent with D.04-09-060, PG&E, SCE and SDG&E shall meet or exceed the Commission's energy efficiency (EE) goals over the next ten years and specifically over the next EE funding cycle (2006-2008) and to revise and update their plans to be in alignment with these goals. PG&E, SCE and SDG&E are to incorporate the goals from the EE decision in their LTPPs, and as these energy savings goals are updated and amended by subsequent decisions, the IOUs are to incorporate the most recently adopted energy savings goals into their plans. As discussed in this decision, the Commission will address all EE program planning and funding level issues in the energy efficiency rulemaking R.01-08-028, or its successor proceeding.

13. At a minimum, the utilities must provide the following data on their energy efficiency programs in the 2006 LTTPs, and concurrently file and serve this data in R.01-08-028 or its successor proceeding:

   a. Total Commission-authorized funding levels in energy efficiency every year over the next decade, broken out into the PGC and procurement component (in real and nominal dollars). If Commission authorization is pending for some or all years of the period, the utilities shall provide estimates of investment levels that are designed to meet the Commission's adopted energy savings goals.

   b. New annual and cumulative energy savings as a result of the programs every year over the next decade, broken out into the PGC and procurement components (in GWh);

   c. New annual and cumulative peak savings every year over the next decade, broken out into the public goods funds (PGC) and procurement components (both coincident-peak and non-coincident-peak, in MW);

   d. The total resource cost (TRC) net benefits of the proposed investments;

   e. The average levelized cost of the energy efficiency resources;

   f. Comparison of cumulative energy and peak savings to the Commission's adopted goals;

   g. The projected percent of demand growth reduced by the programs; and the per capita electricity consumption for the service territory over the next decade after factoring in the energy savings from the programs.

14. We authorize the utilities to enter into short-term, mid-term, and long-term contracts, with contract delivery start date through 2014, provided that the IOUs submit the necessary compliance filings. We adopt The Utility Reform Network's (TURN) proposal that contracts with duration five years or longer be submitted to the Commission for preapproval.

15. We grant PG&E's Petition To Modify D.03-12-062, and clarify that D.03-12-062 authorized IOUs to conduct procurement using negotiated bilateral agreements for transactions of up to three calendar months, or one quarter, forward; and that utilities will consult with their PRGs for transactions with delivery periods of greater than three calendar months, or one quarter. We further clarify that D.03-12-062 authorized IOUs to conduct procurement using an electronic auction format for execution of competitive solicitations, among other transactional methods. The authorized products are good for short-, medium-, and long-term procurement.

16. We grant ten of SCE's twelve requested modifications, as requested in its Petition to Modify, with the exception of modifications seven and nine, as discussed in this decision.

17. The utilities are directed to employ a value to explicitly account for the financial risk associated with greenhouse gas emissions (which we call a "greenhouse gas (GHG) adder"), in the range of \$8 to \$25 per ton of CO_2, to be used in the evaluation of generation bids, in order to select new long-term resource investments that minimize financial risk to ratepayers, as described herein. Each IOU will select a value within the adopted range and respond to party comment on the value, before employing the adder in analyzing RFO responses. Once the Commission adopts a fixed value for GHG emissions (not simply a range) in approximately March 2005 in the Avoided Cost Rulemaking (R.04-04-025), the IOUs will use that value when analyzing bids. Other GHGs, in addition to carbon, will also be included. Additionally, the IOUs will use the value adopted in R.04-04-025 in their next LTPPs when modeling alternative resource portfolios and selecting a preferred portfolio.

18. In addition to the GHG adder, the IOUs are directed to employ, when finalized and approved by the Commission, the additional environmental avoided cost values under development in the Avoided Cost Rulemaking (R.04-04-025). All procurement commenced subsequent to this decision should employ the GHG adder adopted in this decision, until replaced with a decision in R.04-04-025, when analyzing bids.

19. The Assigned Administrative Law Judge (ALJ) and/or Assigned Commissioner (ACR) may direct Commission staff to perform additional studies or analyses on "carbon caps," as needed, in coordination with our consideration of a procurement incentive framework modeled after the cap-and-trade principles of the Sky Trust in a subsequent phase of this proceeding.

20. In soliciting resources in response to these plans, the IOUs are to procure the maximum feasible amount of renewable generation, consistent with the loading order, as described herein. Renewable resources must provide the electricity product sought by the IOU, and, in light of the GHG adder, must be cost-competitive with fossil alternatives.

21. IOUs should file any outstanding proposed renewable energy contracts that rely upon the August 8th, 2003 ACR in R.01-10-024 before February 8th, 2005. Authority granted under the ACR will expire on February 8th, 2005.

22. The IOUs shall employ the Standard and Poor's (S&P) methodology for debt equivalence, except they shall use only a 20% risk factor instead of S&P's 30% risk factor, when evaluating bids in an all-source solicitation.

23. The IOUs shall justify the debt equivalence factors for PPAs on a case-by-case basis in their cost of capital proceedings.

24. The utilities shall refresh the annual capacity and energy tables provided in July in consultation with the Energy Division and the California Energy Commission staff.

25. We continue the required Monthly ERRA Report and Monthly Portfolio Risk Report. The objective of the report is to show that the transactions entered into are in compliance with the upfront standards identified by the Commission. In regards to the Quarterly Transaction Report, the IOUs are ordered to file a joint proposal to reformat the report in a way that will provide the Commission concise and coherent information, thereby streamlining the review process. The objective of the report is to show that the transactions entered into are in compliance with the upfront standards identified by the Commission. These reports will be reviewed by the Energy Division staff. If there are no protests and the staff concludes that the transactions entered into in that quarter comply with the utility's procurement plan, then by the Commission's Expressed Delegation of Authority, the Energy Division Director can approve the reports. However, if there are substantive protests and the staff takes issue with certain transactions, the staff will issue a draft resolution for the Commission's approval.

26. We adopt the following requirements for an All-Source Solicitations:

a. All-source open solicitations need to be transparent and competitive, and in addition, need to be open to all resources (conventional/renewable - turnkeys, buyouts, and PPAs).

b. Following the "loading order" contained in the Joint Agency Energy Action Plan is the first priority for IOU resource procurement, meaning that cost-effective energy efficiency and demand-side resources should be employed first. When these opportunities are captured, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues an RFO for generation resources, it must justify its selection of fossil generation over renewable generation offers.

c. IOUs are directed to procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and will be allowed to credit this procurement towards their Renewables Portfolio Standards (RPS) targets. If an IOU succeeds in procuring sufficient renewable resources to meet its RPS Annual Procurement Target (APT) via an all-source RFO, it will not be required to undertake an RPS-specific solicitation.

d. The IOUs will employ the Least-Cost Best-Fit methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative attributes associated with each bid.

e. GHG adders are to be used for bids in all-source open RFOs.

f. Debt equivalency will be considered when evaluating individual PPA bids, regardless of whether the bids are from a fossil, renewable, or an existing QF resource. IOUs are not to consider resource-specific debt equivalency risk factors.

g. When seeking Commission approval for PPA contracts, the IOUs will need to demonstrate, on a case-by-case basis, that the imputed debt equivalency was material. The IOUs will also need to provide the methodology used to calculate the debt equivalency adder applied to each PPA bid.

h. IOUs will not be allowed to recover costs in excess of its final bid price for utility-owned resources, but Cost Savings will be shared 50/50 between ratepayers and shareholders.

i. Mandate the use of 3rd party evaluators in resource solicitations where there are affiliates, IOU-built, or IOU-turnkey bidders.

27. By this decision we lift the ban on long-term affiliate transactions for transactions entered into through an open and transparent solicitation process. However, we maintain the ban on short-term transactions because the short-term market moves too fast and there is too great of a potential for abusive self-

dealing, with little or no possibility for Commission oversight of these types of transactions**.** The utilities, and in particular their respective risk management committees, must maintain complete procurement planning independence from their affiliates.

28. The IOUs may contract directly with IEs, in consultation with their respective PRGs. The IOUs shall allow periodic oversight by the Commission's Energy Division. Alternatively, Energy Division can contract with IEs directly, but we will not require this given that this may result in unacceptable delays in the procurement process. Independent evaluators shall coordinate to a reasonable degree with assigned Energy Division management and staff as a check on the process.

29. With regard to consultants that assume the role of an IE, they shall abide by clear conflict of interest standards. We note that Federal Energy Regulatory Commission has provided guidance on this issue. We require that consultants abide by the appropriate Fair Political Practices Commission guidelines, in order to avoid the types of conflict of interest problems encountered by consultants working on behalf of the State of California and DWR during the 2000-2001 energy crisis. We must ensure the integrity of the third party evaluator process to provide firm assurances to the power market. We are open to comment from parties on specific conflict of interest standards.

This order is effective today.

Dated ____________________________, at San Francisco, California.

Brown Attachment A
Brown Attachment B
Brown Attachment C