STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

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

January 26, 2004

TO: ALL PARTIES OF RECORD IN RULEMAKING 01-10-024

Decision 04-01-050 is being mailed without the written Concurrence of President Peevey. The Concurrence will be mailed separately.

Very truly yours,

/s/ ANGELA K. MINKIN (by psw)
Angela K. Minkin, Chief
Administrative Law Judge

ANG:acb

Attachment

Decision **04-01-050** January 22, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	Rulemaking 01-10-024 (Filed October 25, 2001))

INTERIM OPINION

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INTERIM OPINION

I. Summary

This decision adopts the long-term regulatory framework under which California's three largest investor-owned utilities, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), will plan for and procure the energy resources and demand-side investments necessary to ensure their customers receive reliable service at low and stable prices. As part of this framework, we promote environmentally sensitive resource choices, set reserve margin standards to protect California's electricity grid, and adopt a process to provide the public and all interested parties more open access to the Commission's decision-making.

In D.03-12-062, we adopted short-term procurement plans for PG&E, SDG&E, and SCE and decided procurement issues which needed to be resolved prior to January 1, 2004. We chose to address the remaining issues that were part of evidentiary hearings held during July and August 2003 in a forthcoming decision. We do that here.

Based on parties' comments, the proposed decision is substantially revised in several areas. The major areas of revision are in reserve requirements, Qualifying Facilities (QF) policy, 2005 operating authority, long term planning assumptions, affiliate transactions, and confidentiality.[1]

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[1] For reserve requirements, the proposed decision is revised to require all load serving entities (LSEs) in the utilities service territories to directly meet our adopted reserve requirement of 15-17% by the beginning of 2008, together with interim benchmarks.

We address here the market structure rules the utilities should follow in making long-term resource acquisitions. We endorse a hybrid market structure for generation. Having provided for direct utility ownership of new plant, we make permanent our ban on affiliate transactions as a direct and effective means of preventing potential conflicts of interest at a level where we have less oversight and control.[2] The holding companies and affiliates of each utility should plan for future generation investment to be made outside of their utility's service territory and sold to other load serving entities. [3]

We look to the utilities to pursue an integrated resource planning process that balances the need for additional generation, transmission, and demand-side investments and to do this in a public proceeding that allows all interested parties an opportunity to participate effectively. We require each utility to adhere to upfront standards in conducting their procurement and to be accountable for operating in a manner that mitigates the risks of high prices, ensures reliable service, and delivers measurable value to their customers.

We adopt here short-term procurement authority for 2005 for the utilities in order to allow them to begin the normal cycle for procuring products required for 2005. We adopt the recommendation of the three utilities, ORA, CEC, and The Utility Reform Network (TURN) to have the utilities resubmit their long-term procurement plans in mid-2004, following the Commission's adoption of specific resource adequacy criteria to be addressed in upcoming workshops. In

[2] However, we do grandfather already existing contractual relationships within affiliates (e.g. QF contracts) for the life of the existing plant order to ensure that existing resources with such relationships can continue to serve California.

[3] SDG&E's RFP is before us as a separate matter and is not addressed here.

the long-term plans that the utilities will prepare, we require each utility to provide a low load forecast that includes Community Choice Aggregation (CCA) and core/noncore scenarios. We also adopt CEC's "no regrets" standard for the review of any long-term commitments the utilities propose prior to our adoption of final long-term plans.

This decision adopts a procedural schedule and process that should allow us to have better load forecast estimates for both CCA and possible core/noncore scenarios prior to the Commission adopting long-term plans at the end of 2004. Through this process, as well as the adoption of a phase-in of the reserve requirement, we address the concerns expressed by local communities and other interested parties that the Commission not take any action here that would preclude their effectively participating in our decision-making.

Finally, we discuss the issues that should be addressed in the new Procurement OIR we expect to open in the first quarter of 2004. These issues are: (1) the need to develop procurement incentive mechanisms for each utility; (2) the need to develop a long-term policy for expiring QF contracts; (3) review of the management audits of SDG&E's and PG&E's electric procurement transactions with their regulated affiliates; (4) handling resource adequacy issues not addressed in the workshop process; (5) review and adoption of revised 2004 long-term procurement plans for the three utilities. We expect to open this new procurement OIR in the first quarter of 2004; and (6) treatment of confidential information.

II. Procedural History

On October 29, 2001, the Commission opened this proceeding to establish the necessary operating procedures and ratemaking mechanisms for the utilities to resume full procurement responsibilities by January 1, 2003. In a series of decisions between August and December 2002, we allocated the existing DWR contracts to each utility, established requirements for the procurement of renewable resources, established cost recovery mechanisms, and adopted short-term procurement plans under which the utilities operate through December 31, 2003.[4]

This decision addresses the long-term procurement planning issues set for further hearing last year in Section X.B. of D.02-10-062.[5] These issues were further delineated at the prehearing conferences (PHC) on February 18, 2003, March 7, 2003, and July 16, 2003. The evidentiary hearings were held from July 21, 2003 through August 18, 2003. Opening briefs were filed on September 15, 2003 and reply briefs were filed on September 22, 2003.[6]

Parties who participated actively in the review of the utilities' long-term plans and 2004 short-term plans are the respondent utilities, Alliance for Retail Energy Markets and the Western Power Trading Forum (ArM/WPTF), the

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[4] The key decisions for allocation of DWR contracts are: D.02-09-053, allocation of existing contracts to each utility; D.02-12-069, adoption of Operating Order between DWR and each utility; and D.03-04-029, adoption of Operating Agreements between DWR and PG&E and SDG&E. Interim procurement authority was authorized for the utilities in D.02-08-071; in D.02-10-062 we adopted the regulatory framework under which the utilities would resume full procurement; and in D.02-12-074 we approved the short-term procurement plans for each utility and set a framework for addressing renewable resources procurement.

[5] In D.03-12-062, the Commission addressed the hearing issues needing resolution prior to January 1, 2004.

[6] Before the Commission in a separate application, A.03-07-032, is SCE's July 21, 2003 Application for Approval of a Purchase Power Agreement with the Mountainview Power Company, LLC. On October 7, 2003, SDG&E filed a motion in this proceeding for approval to enter into new contracts resulting from its Grid Reliability Capacity

Footnote continued on next page

California Cogeneration Council (CCC), California Consumer Power and Conservation Financing Authority (CPA), California Energy Commission (CEC), The California Independent System Operator (ISO), The Cogeneration Association of California and The Energy Producers and Users Coalition (CAC/EPUC), the City of Chula Vista, the City of San Diego, the Independent Energy Producers Association (IEP), The Joint Parties Interested in Distributed Generation/Distributed Energy Resources (Joint Parties), the Natural Resources Defense Council (NRDC), the Navajo Nation, the Office of Ratepayer Advocates (ORA), Save Southwest Riverside County (SSRC), and TURN.[7]

Implementation of Senate Bill (SB) 1078 and SB 1038 legislation on the Renewable Portfolio Standard (RPS) has occurred through a separate workshop process. D.03-06-071 addressed the RPS issues needing to be decided by June 30, 2003 and directed that a new docket be opened to continue with implementation requirements.

Other proceedings that address programs and policies for specific types of resources are: Rulemaking (R.) 01-08-028 for energy efficiency; R.02-06-001 for demand response; and R.99-10-025 and R.98-07-037 for distributed generation (DG). We anticipate shortly opening a rulemaking to streamline the transmission planning process for the utilities in a manner that upholds environmental standards, meets the Commission's statutory obligations under Pub. Util. Code § 1001, and ensures consumer benefits. An OIR to establish policies, procedures,

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Request for Proposals; a separate schedule to consider this motion was set at the October 31, 2003 PHC.

[7] The Navajo Nation's August 18, 2003 motion to intervene should be granted.

and incentive mechanisms regarding DG and Distributed Energy Resources will be forthcoming.

The utilities' procurement plans bring together the policies developed in each of the above proceedings into an integrated resource planning framework.

III. Regulatory Goals and Interagency Collaboration

The three service territories of the respondent utilities account for approximately 80% of California's electricity usage, placing the procurement issues before us here at the forefront of the state's energy agenda:

> "California is a diverse and vibrant society. The fifth largest economy in the world, California's population is expected to exceed 40 million by 2010. California's economic prosperity and quality of life are increasingly reliant upon dependable, high quality, and reasonably priced energy. Following the biggest electricity and natural gas crisis in its history, the state is well aware of the need for stable energy markets, reliable electricity and natural gas supplies, and adequate transmission systems. Looking forward, it is imperative that California have reasonably priced and environmentally sensitive energy resources to support economic growth and attract the new investment that will provide jobs and prosperity throughout the state." (Energy Action Plan.)

The Commission's legislative mandate is to ensure that all utility customers receive reliable service at just and reasonable rates, as specifically stated in Pub. Util. Code § 451 (§ 451), with § 701 giving the Commission power to undertake all necessary actions to properly regulate and supervise California's investor-owned utilities. Our ability to fulfill this mandate was challenged in the energy crisis of 2000 and 2001, both by reliability alerts that included rolling blackouts and by extreme price volatility (i.e., price spikes) in the wholesale price of natural gas and electricity. The crisis led to substantial rate increases for utility customers, financial turmoil for the utilities, their investors, and their creditors, and for two years, from January 2001 through December 2002, the state assumed the utilities' responsibilities for procuring power for customers.

From this crucible of experience, the Commission, the legislature, interested parties, and the public have closely examined market structure issues and questioned the means by which the utilities plan for and acquire energy resources, and the means by which the utilities obtain cost approval and cost recovery for their acquired energy resources. This proceeding is where the Commission has addressed these issues, within the regulatory framework provided by the 2002 legislature in AB 57, and been able to return the utilities to their full procurement responsibilities on January 1, 2003.

AB 57 and SB 1976, codified in Pub. Util. Code § 454.5, provides a regulatory procurement framework for the Commission that (1) requires each utility to prepare and file a procurement plan that meets specified requirements;[8] (2) provides the criteria by which the Commission should review and either adopt, modify, or reject each utility's plan; (3) eliminates the need for after-the-fact reasonableness reviews of utility actions in compliance with an approved plan; (4) ensures timely recovery of prospective procurement costs incurred

[8] These requirements include, among other things, the assessment of price risk associated with the procurement portfolio; a risk management policy, strategy, and practices, including specific measures of price stability; specification of the duration, timing, and range of quantities of each product to be procured; a competitive procurement process; upfront standards and criteria by which acceptability and eligibility for rate recovery will be known; a diversified portfolio to include both short-term and long-term electricity-related and demand reduction products; a renewable resources requirement; and a plan to achieve appropriate increases in diversity of ownership and diversity of fuel supply of nonutility electric generation.

pursuant to an approved plan; and (5) requires that an approved plan enable the utility to fulfill its obligation to serve its customers at just and reasonable rates, with such just and reasonable rates to include an appropriate balancing of price stability and price level.

In 2002, we adopted 2003 short-term procurement plans for each utility under the AB 57 regulatory framework, recognized the need for the utilities to procure reserves on behalf of their customers' needs, and directed each utility to undertake an integrated resource planning effort, based on a 20-year time horizon, to include procurement from a mixture of different sources with various environmental, cost, and risk characteristics. At the February 18, 2002 PHC, as well as in the Energy Action Plan, we emphasized that in making plans to procure a mixture of resources, the utilities should take into account the Commission's longstanding procurement policy priorities – reliability, least cost, and environmental sensitivity; we also stated the Commission's policy preference that resource adequacy be met first through cost-effective energy efficiency programs, other cost-effective demand reduction programs, and cost-effective renewable resources.

In 2003, we carefully reviewed the long-term plans each utility filed, and focused on key policy issues of resource adequacy and market structure. We have reached out in partnership to other agencies, recognizing that common goals exist and can best be met by coordinated action. The ISO is an active participant in this proceeding, and we will rely on their continued involvement in future proceedings. Their analysis and expertise in electricity grid operations and wholesale electricity markets is especially beneficial in setting reliability standards, monitoring and reporting of planning reserve levels, and transmission grid assessment. The CEC and CPA, partners with the Commission in the

Energy Action Plan, also contribute their considerable resources and expertise to our record, and we join with them in pursuing our goal to:

> "Ensure that adequate, reliable, and reasonably-priced electric power and natural gas supplies, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers." (Energy Action Plan.)

IV. Threshold Policy Issues

The three threshold policy issues addressed in this decision are (1) adoption of a resource adequacy framework, to include specific reserve level requirements; (2) adoption of a market structure for longer term resource commitments by the utilities and a requirement to include long-term investment in their procurement planning; and (3) an analysis of whether each utility will be financially capable of making the longer term investments necessary to meet its obligation to serve its customers. In discussing these issues, we give specific direction for the utilities to follow in their procurement planning and operations.

A. Reserves and Resource Adequacy

1. Summary

Resource procurement traditionally involves the Commission developing appropriate frameworks so that the entities it regulates will provide reliable service at least cost. This involves determining an appropriate demand forecast and then ensuring that the utility either controls, or can reasonably be expected to acquire, the resources necessary to meet that demand, even under stressed conditions such as hot weather[9] or unexpected plant outages. "Resource

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[9] Traditionally, this is based on a "1-in-10" year hot weather scenario.

adequacy" seeks to address these same issues. In developing our policies to guide resource procurement, the Commission is providing a framework to ensure resource adequacy by laying a foundation for the required infrastructure investment and assuring that capacity is available when and where it is needed.

In this decision, the Commission (1) directs that each Load Serving Entity (LSE) within the utility's service territory (i.e., utility, Energy Service Provider (ESP) or Community Choice Aggregator) has an obligation to acquire sufficient reserves for its customer's load located; (2) adopts a reserve margin for LSEs of 15-17%; (3) directs the LSEs to meet this 15-17% reserve requirement by no later than January 1, 2008, through a gradual phase-in including the establishment of interim benchmarks to become effective in 2005; (4) establishes a requirement that utilities forward contract 90% of their summer (May through September) peaking needs (loads plus planning reserves) a year in advance;[10] and (5) continues the 5% target limitation on utilities' reliance on the spot market (i.e., Day-Ahead, Hour-Ahead, and Real-Time energy) to meet their energy needs.[11]

An Assigned Commissioner/ALJ Ruling issued in this proceeding on September 25, 2003, directed the convening of workshops to address the issue of standardizing, to the greatest extent possible, the load forecasts and methodologies used by the utilities to value and count resources. Today's decision also provides further guidance on these workshops, particularly on the issue of counting resources, including maximizing the use of the preferred

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[10] Subject to adjustment if implementation results in either significantly increased costs or fosters collusion and/or the exercise of market power in the Western energy markets.

[11] This creates in many respects, a de facto 95% month-ahead requirement.

resources (energy efficiency, renewables, demand response) identified in the Energy Action Plan to meet California's energy needs, and, consistent with the ISO Board's adopted motion,[12] the long-term DWR contracts. Once consistent methodologies are developed, the Commission will work with the ISO and other interested parties to develop appropriate reporting requirements. In the interim, the ISO can continue to monitor the utilities' procurement activities through their on-going involvement (including access to confidential data) of the utilities' on-going procurement related filings. This decision also addresses other miscellaneous issues associated with resource adequacy including deliverability, penalties, and day-ahead commitment. In previous decisions in this proceeding (D.02-12-074 and D.03-06-067), the Commission has already addressed the issue of penalty provisions associated with a utilities' failure to follow its established procurement standards.

2. California Should be Responsible for Determining its Energy Future

Resource procurement inherently involves numerous policy decisions that have significant implications for the cost and portfolio structure of resources used to meet California's energy needs. Given the strong interaction between resource procurement and resource adequacy, it is desirable that California policy-makers have the necessary decision-making authority. It is for this reason that the Commission believes that it should be responsible for

[12] ISO Board of Governors' Resolution approving the ISO's "Comprehensive Market Design" (adopted April 25, 2002) states that: "…any available capacity obligation give full credit to any contracts endorsed by CERS."

addressing resource adequacy for the roughly 90% of the ISO load located within the utilities' service territories. As the ISO notes:

> "[It] is not aware of any other entity besides the CPUC and/or local regulatory authorities (e.g., municipal boards) that can currently impose planning reserve/resource adequacy requirements. Accordingly, the CA ISO considers that the CPUC should clearly define planning reserve/resource requirements for these loads in a manner that is equitable and assures consistent treatment and requirements."

The Commission has routinely advocated, in a variety of forums, that it should address resource adequacy and procurement issues. This position has now been acknowledged by both FERC and the ISO.

FERC, in its recently released "White Paper" on Standard Market Design (SMD) states that it would:

> "Allow an RTO/ISO to "implement a resource adequacy program only where a state (or states) asks it to do so, or where a state does not act."…"*States may decide to ensure resource adequacy through state imposed requirements on utilities serving load within the region*…"[13]

FERC, in its recent October 28th Order addressing the redesign of the California wholesale electric market, reiterated this conclusion noting that it was "encouraged that the State has undertaken a procurement proceeding," (Order, para. 215) and would defer consideration of many elements of the ISO's proposal

[13] FERC White Paper on Wholesale Power Market Platform, p. 5 (Issued April 28, 2003 in Docket RM 01-12-000); *See* also SCE reply brief, p. 46, ftn. 174.

until 60 days after the final rule issued by the CPUC within this proceeding. (para. 216).[14]

Similarly, the ISO has recognized that resource procurement is primarily a state function, and adopted at its November 21, 2002 Board meeting, a resolution to defer consideration of its resource adequacy proposal while directing ISO staff to actively participate in this proceeding at the Commission.

With regard to municipal utilities, as the Commission, the ISO,[15] and CEC[16] have all recently noted, such utilities have traditionally provided reliable service including provision of adequate reserves and have availed themselves of other regulatory options to address resource adequacy.[17] Additionally, the CEC

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[14] FURTHER ORDER ON THE CALIFORNIA COMPREHENSIVE MARKET REDESIGN PROPOSAL (Issued October 28, 2003 in Dockets ER02-1656-003, ER02-1656-004, ER02-1656-015 and EL01-68-028)

[15] In the PROTEST AND COMMENTS ON ISO MARKET REDESIGN PROPOSAL SUBMITTED BY THE PUBLIC UTILTIES COMMISSION OF THE STATE OF CALIFORNIA ON BEHALF OF THE STATE OF CALIFORNA INTER-AGENCY WORKING GROUP submitted in Docket No. EL00-95-001 and ER02-1656-000 (May 30, 2002), the Commission stated (citing from an ISO report) that:

> "Governmental entities have long planned their systems to ensure resource adequacy. In fact, during the advent of competition, while other entities were moving away from the concept of long-range resource planning, government entities were continuing to plan their systems to ensure that they had sufficient resources to satisfy their future load."

[16] In its recently adopted Integrated Energy Policy Report (adopted November 12, 2003).

[17] A significant portion of the municipal load within the ISO is served by municipal utilities which have chosen to become Metered Subsystems (MSS) under the ISO's tariffs (ISO Amendment 46, approved by FERC [100 FERC ¶ 61,234 (2002) (August 30 Order)].

is engaged in collaborative processes with the municipal utilities to address this issue.

3. Policy Issues

While virtually all parties in this proceeding agree that it is critical for the state to ensure adequate reserves and to address resource adequacy, there are a number of policy issues that must be resolved first.

First, there is a trade-off between reliability and least-cost service given the cost to acquire and retain reserves. As TURN's witness Woodruff noted, each incremental increase in reserves offers progressively smaller improvements in reliability.[18] As SDG&E calculated, each additional 1% increase in reserve level adds $2.8 million to its costs.

Second, there is a broad range of resource applications and technologies that California can rely on to meet its reserve levels. The Energy Action Plan, as well as the scope of this proceeding, established a "loading order" for new resource additions emphasizing increased energy efficiency, demand response/dynamic pricing, and renewable energy. The development, timing, and calculation of a reserve level can have a significant effect in promoting (or deterring) development of these new resources. As FERC recently noted in its order on the ISO's proposed redesign of the California wholesale electric market:

> "[R]ushing to relieve inadequate regional supplies and reduce high regional spot prices may bias construction choices toward supply resources that can be constructed

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[18] TURN, Exh. 81, p. 18-19.

> quickly, perhaps sacrificing long-term cost minimization, environmental concerns and fuel diversity goals." [19]

An appropriate balance should be achieved between meeting reserve requirements expeditiously while seeking to optimize the resource mix/portfolio. Paradoxically, rushing to implement a reserve requirement might further increase California's reliance on natural-gas fired resources, posing a different set of reliability concerns if there are supply constraints or price spikes for this fuel.

Third, there is the issue of reliance on the spot market to meet a portion of reserve requirements. While no party advocates extensive reliance on the spot market, most parties believe that it may be both reasonable and prudent to allow for some portion of resource needs to be met through the spot market, a practice that some utilities responsibly engaged in under pre-AB1890 resource procurement.

Fourth, there is the need to ensure that in establishing reserve requirements, we are not creating a potential for the collusion or exercise of market power in the forward markets for capacity. Unlike spot markets, such as the ISO's existing hour-ahead (and soon to be established day-ahead market), there are significantly fewer safeguards and opportunities for regulatory review by FERC of forward market transactions. FERC's recent order denying rehearing of California's request to find that the DWR contracts were not "just and

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[19] FURTHER ORDER ON THE CALIFORNIA COMPREHENSIVE MARKET REDESIGN PROPOSAL (Issued October 28, 2003 in Dockets ER02-1656-003, ER02-1656-004, ER02-1656-015 and EL01-68-028), footnote 98 to para. 215.

reasonable" emphasizes the high burden of proof needed to challenge the reasonableness of forward market contracts.

Fifth, there is the need to evaluate resource adequacy in the context of the broader regional energy markets and under which design rules these markets will operate. Both the ISO, in its MD-02 proposal, and FERC, in its SMD proposal, are in the process of redesigning these markets. Any actions taken by the Commission should work in conjunction with these efforts, not only in the area of scheduling and timing, but also as a complement to effective market mitigation rules. Additionally, the Western energy markets outside of California have neither functioning ISOs nor any resource adequacy or capacity market requirements. Therefore, in adopting resource adequacy requirements, we must ensure that we are not unilaterally imposing burdens upon California's utilities —and by extension California's economy — to which utilities located outside of California are not subjected.

Based on the above concerns, we believe that the best way to achieve these goals is for California to set, control, and enforce its resource adequacy policies at the state level.

4. Current and Forecasted Market Conditions

A key factor for consideration in evaluating resource adequacy is the current state of the wholesale energy market in the West, and the degree to which California's utilities have obtained or can access these resources to meet their energy needs. Many of the parties believe that adequate reserves should exist until around the year 2008. A late-filed exhibit, consolidating each utilities' resource needs and comparing it to available supplies, concluded that:

> "[T]here appears to be sufficient existing, and highly probable new generation, located outside of California or

> importable over existing transmission ties, to meet IOU reliability needs (including a 15% reserve requirement) over the time period 2004-2010."[20]

PG&E believes that sufficient resources will be available to California to meet its requirements until around 2010. Equally important, almost all parties believe that there are ample amounts of resources available for California to meet its resource needs for 2004, thus providing the Commission a window to develop an optimal resource procurement strategy.

Based on its review of the California energy market, the CEC believes that new capacity needs are unlikely to occur until 2007, at the earliest. As the CEC also notes, its review and those of the utilities are based primarily on a review of existing and planned generating resources and do not consider non-generating resource additions, such as increased funding for energy efficiency, that would defer even further into the future the need for new resources. These conclusions are consistent with the CEC's Integrated Energy Policy Report (IEPR) adopted in November 2003. The CEC expresses the concern that focusing on reserve levels based only on generating resources may bias planning decisions to the detriment of demand-side resource options. According to the CEC, the successful implementation of additional energy efficiency and demand response programs can allow California to maintain sufficient reserves even further into the future , that is, beyond the 2007-2008 timeframe, even if there is little or no new generation being built. For example, the CEC's IEPR forecast does not include the additional procurement-related energy efficiency funding

[20] Exh. 68 prepared by Mr. Lauckhart at the request of ALJ Walwyn.

the Commission approved in this docket on December 18th in D.03-12-062, expected to total 950 MW over five years.

In its recently issued decision addressing SCE's application SCE to enter into a Purchase Power Agreement with the 1,054 MW Mountainview power plant project, the Commission concluded that:

> SCE has forecast that considering its existing resource base of utility-owned generation, QF contracts, interutility contracts, Department of Water Resources (DWR) allocated contracts, and transitional contracts, when combined with expiring contracts, forecasted load growth, and the assumed reserve requirements, it will need more capacity by 2006. *SCE does admit that there are existing uncommitted resources to meet any gaps between now and 2006. However, moving forward, SCE forecasts a need for dispatchable, peaking and intermediate resources in the short-term,* and baseload over the long term. Mountainview with its 1,054 MW combined-cycle, in SCE's service territory capacity satisfies this resource need. We make this finding independently of any finding concerning the future of Mohave, or QF contracts. (D.03-12-059, p. 33, emphasis added.)

The ISO and CPA, by contrast, expect that capacity constraints could appear earlier than 2007, and that setting a reserve requirement will assist in ensuring that existing resources remain available for use.[21] IEP and WPTF make

[21] It should be noted that the ISO Forecast does not include recent actions taken by the Commission to improve the supply situation such as the 1,054 MW Mountainview project (D.03-12-059); increase energy efficiency funding totaling 950 MW over five years (D.03-12-062); or SDG&E's recently proposed 500 MW Palomar facility which the Commission will consider soon. The ISO's forecast also does not include the 1,100 MW of the existing interruptible program.

somewhat similar points, arguing that ensuring the availability of existing resources should be considered in setting reserve levels.

Based on the assessments described above, we conclude that there are ample resources for California to meet demand for 2004 as well as adequate resources available for California to meet peak demand through 2007 although all of these forecasts, particularly in the "out" years, contain some element of uncertainty.

5. Appropriate Reserve Levels and Phase-in Period

The relative balance between California's energy needs and the resources available to meet them is important in determining the procurement strategies of the utilities' in acquiring reserves.

In D.03-12-062 the Commission adopted the Joint Recommendation's statement that reliable operation of the electric system requires two types of reserves — operating reserves and planning reserves. In order to ensure reliability, a grid operator must ensure that there are sufficient resources available to meet peak demand, plus an additional reserve to accommodate unexpected outages. The level of the reserve is determined by the Western Electricity Coordinating Council and is approximately 7% of peak demand.[22] This is the operating reserve.

[22] As the Joint Recommendations states, the level of operating reserve was last "…defined in the April 2003 WECC Minimum Operating Reliability Criteria ("MORC"). MORC includes "contingency reserves," which is capacity needed to cover the greater of the largest single generation or transmission contingency, or 5% of the load met by hydro generation plus 7% of the load met by thermal generation."

Planning reserves involve a longer-term perspective of ensuring that in real-time there will be sufficient energy to meet peak demand plus needed operating reserves. Typically this requires that a utility have more than 7% reserves, since at any given time some percentage of plants may not be available due to such factors as maintenance, forced outages, fuel limitations, or in the case of hydroelectric power, insufficient water.

The Joint Recommendation defined planning reserves and operating reserves as follows:

- Planning Reserve Margin (“PRM”): The reserve margin shall be an obligation over and above the capacity required to meet peak demand. PRM is computed as follows: PRM = [(Dependable Capacity / Peak Load) – 1] x 100%. In calculating PRM, “Dependable Capacity” shall not be reduced to reflect Reasonably Expected Resource Outages.[23]
- Operating Reserve Margin (“ORM”): ORM shall be used for purposes of reviewing resource adequacy over a shorter term, such as a year or less and shall be applicable to short term procurement plans. ORM is computed as follows: ORM = { [(Dependable Capacity – Reasonably Expected Resource Outages) / Peak Load] – 1} x 100%.

While virtually all parties agree that it is appropriate to set a longer-term planning reserve level, parties disagree over both the level and whether a phase-in period should be used to achieve it. In D.02-12-074, the Commission provisionally adopted a 15% reserve level subject to further revision in this proceeding.

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[23] The Joint Recommendation proposes that the terms “Dependable Capacity,” “Peak Load” and “Reasonably Expected Resource Outage” should be defined as part of a permanent resource adequacy framework to be developed. (See Section I.8 of this Joint Recommendation.)

The Joint Recommendation[24] proposes a 15% planning reserve, phased in starting in 2005 and ramping up through 2008, based on equal percentage increments (i.e., 2% per annum increase). For 2004, the utilities will meet the 7% operating reserve level required of the ISO, as approved by this Commission in D.03-12-062.

The CPA recommends the adoption of a 17% reserve level, based upon a study it conducted and that was officially noticed as part of the record in this proceeding. The ISO supports the 17% reserve level, and also supports a three-year phase in to achieve this level, provided that the utilities meet a 90% year-ahead and 100% month-ahead capacity requirement. The ISO notes that a three-year phase-in would help alleviate concerns over the exercise of market power in the forward market. Finally, IEP supports the 17% reserve level, while WPTF states that the reserve level should be "at least 15%."

Based upon the record developed in this proceeding, we believe that a planning reserve level of between 15-17% should be adopted for all LSEs, which should be phased in by no later than January 1, 2008, as we are essentially adopting the target level proposed by the Joint Recommendation. In their procurement fillings, the utilities should justify any reserve levels above 15%. We recognize that there is an inherent "lumpiness" to resource additions and the utilities may end up with reserve levels above 15% depending upon the timing of resource additions.

In approving a 15-17% planning reserve we carefully considered the CPA's proposal for a 17% reserve level. We note the concerns of many parties

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[24] The Joint Recommendation was submitted by SCE, PG&E, SDG&E, TURN, ORA and the CEC.

that the CPA's analysis may contain overly pessimistic assumptions about the shape of the future market and we note that the ISO found that additional utility-specific analysis is needed to determine an appropriate forced outage rate, a key determinant for setting an appropriate reserve level.[25], [26]

A 15-17% reserve level should provide not only reliable service but also an additional margin of safety. As PG&E states:

> "Based upon the simulations performed by Henwood, a 15% reserve requirement produces a 2006 loss of load probability of 0.2 days in 10 years."
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> * * *
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> "TURN witness Woodruff concurs that a 15% planning reserve level would result in a "one day in fifty years" generation reliability criteria and that this level of reliability is reasonable.[27]

SCE and SDG&E reach similar conclusions. A 15% reserve level is also the minimum level that the ISO determined would provide reliable service

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[25] MR. PETTINGILL: Well, that's part of what goes into the assessment when they start with the baseline of 1 day in 10 years. Then they look at the historical outage rates of the different technology units, the size of those units, and then determine what's an appropriate reserve margin to meet that one day in 10 years.

COMMISSIONER WOOD: Has Cal ISO conducted that type of analysis in arriving at a recommendation of 17 percent for our utilities?

MR. PETTINGILL: We have not done the analysis. (Tr. 5991-5993.)

[26] In its 5-year Forecast released in October 2003, the ISO calculated an average forced outage rate of about 7.2%.

[27] PG&E Opening Brief, p. 34.

when setting standards for municipal utilities to become metered subsystems (MSS) under its tariffs.[28]

With regard to an appropriate phase-in period, the utilities and LSEs should meet this 15-17% requirement by no later than January 1, 2008, with interim benchmarks established starting in 2005. The starting point for compliance will be determine in the workshops. While these are minimum standards, the utilities should justify proposed reserve levels above 15% in their procurement filings and explain why reserve margins higher than 15% would be appropriate.

A 15-17% reserve level, phased in by 2008, ensures reliable service by providing incentives to encourage the retention of existing resources and avoids setting reserves at levels that could require the utilities to make short-term investment decisions inconsistent with the Energy Action Plan's preferred "loading order" of new resources. For example, imposing a high reserve level quickly might require utilities to enter into longer-term contracts for capacity, thus crowding out preferred resources, such as demand response and energy efficiency, which are currently propose to come on line in significant quantities in 2006 and beyond.

As several parties noted in response to the Proposed Decisions, a too-rapid implementation of a reserve requirement could create a "gold-rush" with utilities forced to sign-up all available capacity in order to meet their reserve requirements. Additionally, there is almost 3,000 MW of capacity that is currently required to be offered to the marketplace through 2006 as part of a

[28] ISO Tariffs, Sec. 23.16.2

settlement regarding market manipulation in the California energy market. Setting a reserve requirement either too high or reaching it too quickly could result in California utilities potentially having to pay excess amounts to acquire these resources that otherwise would be offered at cost to the market as compensation for past abuses.

In its Standard Market Design (SMD) proposal, FERC recognized that it is appropriate to phase in any resource adequacy requirement in order to allow entities time to meet the requirement and to prevent the exercise of market power. In its SMD proposal, FERC recognized that a 3-5 year period, with interim benchmarks, was acceptable,[29] and FERC's recommendation is consistent with the four year phase-in period adopted here.

By having the Commission set the phase-in period, we retain the ability to quickly revise the reserve benchmarks should market power prove to be a problem. In their original resource adequacy proposal, and in their testimony in this proceeding, the ISO is not proposing to place any price caps or restrictions upon the prices charged for capacity.[30] Setting a reserve requirement imposes an asymmetrical obligation on market participants, where LSEs are obligated to procure capacity or face potential penalties, yet suppliers have no corresponding obligation to offer capacity at reasonable prices. Therefore, the

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[29] FERC Standard Market Design Tariff NOPR, para. 522-524 (Docket No. RM01-12-000 issued July 31, 2002)

[30] The prices charged for capacity would be considered wholesale transactions and thus subject to regulation by FERC. While the ISO has proposed price caps on energy transactions in its Market Design, it has not proposed any limits on capacity prices.

Commission retains the right to adjust the phase-in period as necessary to protect against market power abuses.

Finally, a phase-in period recognizes that prioritizing each utility's need may be appropriate, given their current financial resources. In not proposing to set any restrictions on capacity prices in the wholesale energy market, the ISO believes that the cost of building new generation would serve as a de facto price cap on capacity prices. While such a conclusion may be reasonable for capacity markets such as PJM or New York, where import/export capabilities are limited and most capacity needs are self-provided, such a conclusion may not be applicable to the California market which has a significant amount of divested generation, expiring QF contracts, and reliance on imports. Higher prices in the capacity markets from a too rapid implementation of a reserve requirement could limit the amount of funds that California's utilities would have available to meet other Commission goals such as achievement of the Renewable Portfolio Standard.

In setting the target of 15-17% by the beginning of 2008, we do not believe that we are setting a reserve level that will be difficult for the utilities to achieve. WPTF observed that each of the utilities' original filings proposed target reserve levels in the 15-17% range to be achieved by the 2005 time period.[31]

Additionally, although several parties were opposed to the Joint Recommendation's proposal that each utility only meet the ISO's proposed 7% operating reserve requirement for 2004, a closer look at the utilities' filings shows

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[31] The initial recommendations of the utilities were; SDG&E, 15% with a +/- 2% deadband; PG&E, 7% for 2004, increasing to a 15% in 2005; SCE, 17% in both its Preferred and Interim Plans.

that their actual planning reserve margins for 2004 were significantly above the 7% minimum. SDG&E's testimony, for example, showed that it possessed sufficient capacity, either owned or under contract, to easily meet the 7% operating reserve requirement, implying that SDG&E's actual planning reserve levels were well above 7%. A review of SCE's filing shows that, in determining its resource needs, it had already included in its calculation estimates of expected plant availability, a major component of a planning reserve level, as well as excluded its interruptible load programs in calculating its reserve level. Thus, SCE's actual planning reserve margin would appear to be significantly higher, perhaps in the 12-13% range, for 2004. Only for PG&E does it appear that there might be some over-reliance on spot purchases, but again PG&E's original filing did not include its subsequent procurement efforts, approved by the Commission, to firm up a significant portion of its outstanding short position.[32]

[32] In D.03-08-066, the Commission approved PG&E's request to solicit offers to procure up to 50% of its non-baseload needs for 2004; and in Resolution E-3853 approved PG&E's request to procure additional renewable resources to meet its RPS targets.

6. Appropriate Balance Between Forward Contracting and Spot Purchases

The ISO was the only party to propose specific percentages that each utility should forward commit to, proposing that utilities forward contract 90% of their capacity needs (i.e., annual peak load plus the target reserve level) a year in advance and 100% of their monthly peak capacity need plus reserves a month in advance. SCE and PG&E specifically opposed this proposal. The Joint Recommendation proposes that the utilities can rely on "spot capacity" purchases for 2004, and that, going-forward, some reliance upon "spot capacity" may be appropriate. In addressing this issue we note that there is no analytical support behind the ISO's proposed benchmarks. As the ISO's own witness noted, the 90% figure was a number within a range and that other numbers, such as 85% might be equally appropriate. [33]

In determining what an appropriate benchmark for forward contracting should be, we should begin our analysis of what the *de facto* percentage of forward contracting is based upon each utilities' existing portfolio of retained generation and assigned DWR contracts. Summarizing at a high level, in order to respect confidentiality concerns, it appears that for many months of the year (particularly off-peak or shoulder months) the utilities are already forward contracted at the 90% level and in some months may actually be net sellers into the market (i.e. greater than 100% coverage). Even for the peak periods during the summer months, the degree of forward contracting appears to be in the 70-75% range, without taking into account subsequent activities undertaken by the utilities since the time of their filings.

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[33] Pettingill, Tr. 4451

The question therefore becomes what are the benefits of further forward contracting. As noted when the DWR contracts were originally signed, it was thought that being forward contracted at somewhere around the level of 70-80% was sufficient enough to minimize the incentives for generators to engage in physical or economic withholding.[34]

Equally important, as PG&E and SCE note, imposing a mandatory percentage of forward contracting is inconsistent with the risk assessment models the utilities are supposed to develop and use to measure and report ratepayer risk exposure.[35] The purpose of these models is to measure utility portfolio price risk exposure vis-à-vis consumer risk tolerance. Thus, the application of these models should inherently result in utilities seeking to forward contract to a significant extent, to minimize exposure to any high prices or reduced reliability from spot market purchases. Optimally designed, these risk assessment models would more precisely match and determine the optimal forward contracting strategy than setting an arbitrary percentage as the ISO proposes. Supporters of the Joint Recommendation raise a similar issue, namely that in advocating for the utilities to procure some portion of their capacity needs in the spot capacity markets they do not mean purchasing all of this need in the

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[34] For example, in a market of 100 MW where 50 MW are subject to the spot market, a generator who withholds a MW of capacity can benefit from the increased price for the remaining 50 MW of demand in the spot market. If, however, due to forward contracting, only 10 MW are subject to spot prices, than a generator who withholds a MW of capacity only sees a higher price for 10 MW, not 50 MW. At some point, the foregone revenue from reduced sales by withholding capacity is greater than the increase in revenues that result from withholding this capacity.

[35] The actual use and evaluation of the utilities' models is discussed elsewhere.

day-ahead/real-time markets, but instead that these purchases would occur in a continuum, based on market and supply/demand conditions, presumably between the year-ahead and hour-ahead markets. It is therefore unclear what, if any, distinction exists with regard to reliability, if a utility contracts for its needs only 9 to 10 months in advance instead of 12 months.

However, given that for many months there appears to be a relatively small difference between the current de facto level of forward contracting and the 90% level, we do not see a need to adopt the 90% level on a year-round basis. However, we are concerned that sufficient resources be available during the peak summer months when the utilities are more exposed to the market and prices are likely to be higher. Therefore, we will require the utilities to forward contract for 90% of their summer monthly peak needs. Because of the inherent uncertainty as to when hot weather may occur, we define the summer peak period more broadly than suggested by some parties such that it includes the entire months of May through September.

The question we need to decide is whether this 90% level should be a target or a requirement. To help promote reliability, we will make this a requirement for the utilities but will allow the utilities the flexibility to justify to the Commission the need to dip below this level on a case-by-case basis. Thus, the 90% level serves as a benchmark and further safeguard operating in conjunction with each utilities' risk assessment models. Granting the utilities some flexibility provides protection against the exercise of market power in the forward capacity markets, a concern noted by many parties, including the ISO. It also allows the utilities to account for unusual market conditions. Because of the difference between the existing level of forward contracting (70-100%) and the proposed target, utility compliance with this level appears feasible. Establishing this requirement for 2004 is unrealistic and therefore, it is appropriate to defer implementation of this requirement to the beginning of 2005.

The ISO is the only party that proposes that utilities' forward contract for 100% of their needs month ahead, a position opposed by other parties. The ISO provided no economic analysis as to either the increased cost of implementing this proposal or what incremental effects it would have on improving reliability. The reasoning behind the ISO's proposal appears to be based on resource adequacy programs adopted in other parts of the country, such as the PJM pool and New York ISO which impose similar requirements. However, while these other ISOs are largely self-contained, with limited import/export capability, it is unclear how such a requirement would be imposed upon California. Historically, California has relied on, and benefited from, the diversity of load throughout the Western United States, much of which is still provided by vertically-integrated utilities. Because not all of these utilities generally peak at the same time, at any given moment there are usually surplus energy resources available for purchase. These same utilities, however, would be reluctant to commit these resources to California a month in advance, since they will not know when their respective peak demands are likely to occur. The ISO addressed this issue recently when it modified its rules to encourage out-of-state energy resources to increase their level of bidding into the ISO's hour-ahead market, recognizing that these exceedingly short-term resources are useful in ensuring the provision of reliable service.

Imposing a month-ahead requirement at this time is therefore likely to limit opportunities for California to take advantage of this diversity and result in higher prices. As the Joint Recommendation notes, it appears that utilities can rely upon uncommitted supplies for a portion of their energy needs while still ensuring reliable service. A late-filed exhibit by PG&E noted that prior to AB1890 it often included uncommitted capacity (i.e., capacity that PG&E expected to be available but was not under contract) in its resource plans. [36]

The Joint Recommendation cautions that the degree of reliance upon this capacity needs to be carefully evaluated. In large part, this depends upon the shape of the underlying market and expected availability. A better approach to ensuring reliable service is to limit each utility's reliance on spot market purchases less than a month in advance to be based on reasonable (and perhaps even conservative) estimates of the energy available in this market.[37] For example, we do not want all three utilities assuming they will be able to acquire the same surplus energy from the Pacific Northwest. Thus, reasonable estimates, taking into account expected loads/resources in the Western region, and the procurement strategies of energy purchasers in the West would be helpful to define a reasonable estimate of appropriate reliance on the short-term energy markets. It is precisely this sort of issue that the CEC is examining as part of the Western Resources Assessment Team (WRAT) and as part of its IEPR process.[38] This issue will also be further addressed in workshops.

In not adopting the ISO's request we are not advocating extensive reliance upon the spot market. In D.02-10-062 the Commission adopted a target limitation on spot purchases to less than 5%. This limit was to provide a balance

[36] PG&E, Ex. 162 noting a reliance of about 10% on uncommitted capacity.

[37] For example, as WPTF states: "While some reliance on spot power is appropriate, WPTF submits that over-reliance is not in the ratepayers' best interests." (WPTF Opening Brief, p. 9)

[38] An issue for further analysis proposed by the Joint Recommenders.

between flexibility and reliability. This is a reasonable limitation and additional safeguard which should continue in the utilities' current procurement practices. Additionally, we will allow the utilities' to continue to rely on short-term and spot market purchases to meet their energy needs but only if they have met their capacity requirements in advance. Thus, if the utility has sufficient reserves under contract to ensure resource adequacy but can tap the spot markets in real time at a cost below its call options on contracts, the utility can go beyond this 5% threshold for energy.

It is also important to examine the rationale behind the ISO's proposal. The ISO is proposing not only that LSEs acquire 100% of their needs a month in advance, but that the ability to dispatch and operate these resources also be turned over to the ISO in the day-ahead market. As PG&E notes, this could result in resources acquired by PG&E being used to meet the needs of any other entity within the ISO such as SCE, the City of Roseville, or theoretically even merchant generators wheeling power through the ISO grid. This "pooling" approach to dispatching resources runs counter to the Commission's findings in D.02-09-053, when it rejected a proposal to jointly dispatch the DWR contracts and instead emphasized the importance of each utility operating and managing its own resource portfolio.

SCE notes that while it supports in concept the notion that resources should be made available in the day-ahead market for dispatch, such a requirement might better be achieved through the ISO's tariffs and market rules, and not through imposing it as a requirement of a contract. Additionally SCE notes that such a requirement cannot legally be imposed upon either its QF resources or upon most of their existing DWR contract resources due to contractual limitations. In its comments to the ISO and FERC, the Commission has raised similar concerns, noting that this again imposes an asymmetrical obligation upon LSEs. LSEs are obligated to acquire resources and then turn dispatch decisions over to the ISO while there is no similar obligation directly imposed upon energy resources within the ISO grid.

It is premature at this time to impose a 100% month ahead requirement upon California utilities when there is no similar requirement upon any other utilities within the West and the ISO's final market rules are still in development. We realize that part of the ISO's desire to impose this month-ahead obligation is the perceived uncertainty over whether FERC will continue its current real-time must-offer obligation and/or extend it to the day-ahead market as the ISO has requested. The Commission's position has been that a must-offer requirement is a valid and reasonable condition to impose upon generators. If and when a region-wide resource adequacy framework is developed for the West, then a 100% month-ahead requirement may make sense. In the interim, it is likely to have the effect of limiting California's procurement choices and putting California consumers at a disadvantage relative to consumers in other states. For the foregoing reasons, we do not adopt a month-ahead procurement requirement.

7. LSE Obligation to Procure Reserves for all Load and Customers that it Serves

Today's decision requires each LSE within the utilities' service territories to be responsible for procuring, under Commission oversight, sufficient reserves to provide reliable service to its load.

Virtually all parties that addressed the issue agree that ensuring adequate reserves for all load within the utilities' service territory is a critical and important issue. The Joint Recommendation, for example:

> "...[A]gree[s] that capacity and reserve requirements must apply to both IOU bundled customers and Direct Access and Community Aggregation customers, regardless of what entities are ultimately responsible for acquiring the capacity and reserves."[39]

There was disagreement among the parties, however, as to the appropriate entities that would be responsible for achieving and implementing this goal. Even the Joint Recommendation did not reach a consensus viewpoint on this issue.[40]

WPTF and SDG&E believe that either FERC or the ISO should have this responsibility for all load-serving entities, including the utilities. PG&E appears to suggest that the ISO should perform this duty only for the ESPs. Both of these approaches would conflict with the Commission's position, filed in comments before FERC, that resource procurement is fundamentally an issue of state, not federal, concern, and that imposition of a resource adequacy requirement would infringe upon the state's right to self determination on this issue. It is inconsistent with both FERC and the ISO's stated policies of giving deference to states to address resource adequacy issues.

Adopting either of these approaches would also preclude the Legislature from addressing this issue as well. To date, both of the major

[39] Joint Recommendation, Sec. I 9.

[40] "This Joint Recommendation does not address nor take any position on whether and to what extent the IOU's should procure capacity and reserves for Direct Access customers. However, if IOUs are required to procure capacity and reserves for Direct Access customers, appropriate adjustments in capacity and reserves will be necessary and IOUs should be compensated in full for such procurement." (Joint Recommendation, I. 5.)

legislative proposals to change the existing market structure (AB 428 and SB 888) specify that the Commission should address resource adequacy issues.

TURN notes the jurisdictional confusion that would arise from having the ISO seek to enforce CPUC-adopted reserve requirements. This would put the ISO in the position of enforcing rules it did not create. Additionally, it is unclear how the ISO could enforce these rules without doing so under FERC-approved tariffs, thus transferring final decision-making authority over California's energy future away from California to Washington. As an example of the potential conflict between federal and state regulation, some of the parties advocating that resource adequacy should be addressed at the federal level are the same parties who have argued against allowing the "preferred resources" identified in the Energy Action Plan (such as energy efficiency) from being counted toward meeting any resource adequacy requirement, thus negating their value and biasing resource decisions towards generation resources. [41]

The preferred approach is for California to address the resource adequacy at the state level. TURN, the ISO, and SCE all recognized that the state is the appropriate entity to address reserve issues.

In determining how the Commission should address this issue, two approaches were proposed. They are:

- Each LSE in the utility service territory (utility, ESP, community choice aggregator) would be responsible for acquiring its own reserves needed to ensure reliable service; or,
- The utility would acquire reserves for all load within its service territory including that of ESPs and community choice aggregators.

[41] **See** for example, WPTF Opening Brief, p. 9.

Putting aside the issue of jurisdiction, almost all parties expressing an opinion on this issue, except SDG&E,[42] believe that the preferred approach is to require each LSE to be individually responsible for acquiring its own reserves. This approach would be administratively more simple, allow each LSE to decide how to best meet Commission-imposed requirements, and properly assign responsibility for providing reliable service.

The major impediment to implementing this approach is a perceived concern as to whether the Commission currently has the jurisdictional authority to impose resource adequacy requirements upon ESPs and community choice aggregators. PG&E, SDG&E, SCE, and TURN all believe that the Commission has the requisite authority. ARM and WPTF do not. SDG&E and SCE both note that the Commission could impose reserve requirements upon non-utility LSEs (such as Energy Service Providers or ESPs) under the requirements of Pub. Util. Code § 394. This code section allows the Commission to determine that ESPs demonstrate "technical and operational reliability" and "financial viability." Similar legislative requirements apply to community aggregators as well. Under the requirements of AB 117, community aggregators must demonstrate both "reliability" (Pub. Util. Code § 366.2(c)(4)(b) as well as "any other requirements established by state law or by the Commission concerning aggregated service" (Pub. Util. Code § 366.2 (c)(4)(D). Requiring an ESP or community aggregator to

[42] SDG&E's proposal would create an ISO-capacity market where the ISO, not the Commission, would oversee the acquisition of capacity through formats such as auctions or RFPs.

acquire adequate reserves in order to ensure reliable service would appear to clearly fall within this legislative authority.[43]

As Sempra states, "apart from the law and theory, the State as a matter of public policy may determine that system reliability requires that LSEs meet a resource adequacy test, inclusive of supply reserves."

ARM and WPTF dispute this contention, relying primarily upon Commission decisions D.98-03-072 and D.99-05-034[44] where the Commission initially defined an ESP's responsibilities under the requirements of Pub. Util. Code § 394. In both of these decisions, the Commission chose to narrowly define its jurisdiction, allowing an ESP to meet the requirements of Pub. Util. Code § 394 primarily by proving it had the technical capabilities to interact with the utilities' billing and metering systems and the ISO's scheduling protocols. This latter function was verified through an ESP either becoming or contracting with an ISO Scheduling Coordinator (SC). ARM/WPTF also state that imposing a reserve requirement upon ESPs would conflict with the "terms and conditions"

[43] Requiring ESPs to acquire their own reserves is also consistent with the approach for addressing resource adequacy proposed in SB 888. The latest substantive version of SB 888 (July 1, 2003):

> "Requires electric service providers to comply with conditions, including resource adequacy standards, that the commission determines to be necessary and appropriate to ensure there is no adverse effect on the reliability or cost of electricity for core customers." (Proposed Pub. Util. Code § 365(h).).

[44] These decisions resulted in the adoption of Rule 22, also cited by ARM/WPTF.

under which direct access customers take service that is not allowed under Pub. Util. Code § 394.[45]

In reviewing ARM/WPTF's claims, we are unpersuaded that the Commission does not have the authority, if it chooses to exercise it, to impose broader reliability requirements upon ESPs, such as a resource adequacy requirement. Although the Commission chose to narrowly limit the exercise of its jurisdiction in implementing Pub. Util. Code § 394, it is a well-settled legal principle that there is no legal or statutory prohibition against the Commission revisiting and revising its authority in a subsequent proceeding. As SCE states: "If the Commission can develop those standards, it can certainly modify those standards if there is a need to ensure reliability."[46] This is particularly true when the circumstances upon which the original decisions were based have changed.

At the time that both D.98-03-072 and D.99-05-034 were issued, the underlying assumption of the Commission was that reliability in the electric markets could be achieved by market mechanisms such as the Power Exchange and ISO.[47] Subsequent events have proven that this may not occur absent proper

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[45] ARM/WPTF make a subsidiary claim that imposing a reserve requirement upon ESPs would require them to divulge their underlying supply contracts and that this would violate Pub. Util. Code § 399.14(b)(3)(B) which states that "nothing in this subdivision may require an electric service provider to disclose the terms of the contract to the Commission." However, this Code section (part of the Renewable Portfolio Standard) only applies "for purposes of this Article [16]"(i.e. how the Commission chooses to implement the RPS standard and does not limit or preclude any other jurisdiction the Commission may possess through other provisions of the Pub. Util. Code.

[46] SCE Brief of Issues in Compliance with March 7, 2003 Order, p. 11.

[47] **See** for example Pub. Util. Code §§ 330 and 350.

safeguards. During the tight energy supplies and market manipulation of the California energy crisis, for example, high energy prices created financial problems for ESPs, which were then unable to provide reliable service to their customers.[48] The level of direct access load falling from 15% to 2%, with the result that the utilities, and later DWR, were obligated to assume the procurement of energy for many of their customers. Separately, as TURN notes, it is not clear if ESPs have the appropriate financial incentives to ensure reliable service under adverse conditions. Thus it would be appropriate if the Commission were to decide that additional safeguards should be imposed upon ESPs under the requirements of Pub. Util. Code § 394.[49]

We do not find that requiring ESPs to meet a reliability obligation under Pub. Util. Code § 394) would conflict with the "terms and conditions" under which direct access customers receive service. In setting a requirement upon ESPs, the Commission is not affecting any of the contractual relationships between the ESP and the direct access customer. The ESP remains free to request whatever pricing and other terms it desires from the customer. One of the main purposes of a reliability requirement, by contrast, is to ensure that the failure of an ESP to procure sufficient reserves does not affect *all other* customers on the grid.

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[48] In part this was due to the inability of the utilities to compensate ESPs when the PX-component of the energy bill exceeded the otherwise applicable tariffed rate.

[49] Although it has no legal impact or authority, AB428 would "*affirm* the electrical corporation's obligation to provide transmission, distribution, and *resource adequacy services for all customers*", thereby envisioning that the Commission already has the authority to impose resource adequacy obligations upon ESPs.

Another proposal offered by TURN would require that the utilities acquire sufficient reserves to meet the needs of all customers within their service territories. TURN argues that this approach is consistent with how the utilities have traditionally procured resources to meet the needs of their customers. In procuring reserves in order to provide reliable service, the utility traditionally had to factor in the potential that other market participants would either under-procure or lean on the system, thus requiring the utility to acquire additional reserves in order to ensure reliable service to its customers.[50]

TURN argues that under existing law the utilities remain both the default provider and provider of last resort for all load within their service territory. Thus, when the level of direct access load shrank from 15% to 2% during the energy crisis, it was the utilities that were obligated to acquire energy to meet the needs of these customers. TURN argues that it is prudent to have the utilities acquire reserves to plan for such a contingency. SDG&E also stated that having utilities acquire reserves for all of the customers in their service territory was legally supportable under the Commission's obligation to ensure that utilities provide reliable service.[51]

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[50] Although in the pre-restructuring time of traditional vertically-integrated utilities it is not clear how often under-procurement occurred.

[51] SDG&E Pre-hearing Opening Brief in response to ALJ's March 7th Ruling. SDG&E references Pub. Util. Code § 451 as a "legal basis for the Commission to impose on utilities an obligation to acquire adequate capacity for direct access and other customers" and that: "…The Commission also has the authority to address unsafe, improper, inadequate, or insufficient utility rules, practices or service (see, e.g., Public Utilities Code Sections 701, 761, 762, and 768)."

As TURN and ARM/WPTF both note, ESPs appear to generally rely on short- to mid-term contracts to meet their energy needs. In support of its proposal, TURN states that given the changing and fluid customer base that most ESPs utilize, ESPs may not have sufficient incentives to acquire necessary reserves.

It is noteworthy that TURN's proposal is consistent with the approach to addressing resource adequacy issues envisioned in AB 428.[52] Under the proposed requirements of AB 428:

> "…[T]he commission [in consultation with the CEC and ISO] shall establish resource adequacy requirements that ensure the availability of planning reserves sufficient to serve all customers of the corporation, including noncore and community choice aggregation customers. The resource adequacy requirements shall ensure cost recovery by the electrical corporation for acquired reserves through a nonbypassable component of the electrical corporation's transmission and distribution charges." (AB 428, proposed PU367.6 (i).)

TURN's proposal also acknowledges that the utilities (and their customers) should not subsidize ESPs. It therefore proposes a non-bypassable surcharge so that all customers within the utility service territory pay their fair share of the costs of acquiring needed reserves. Such a surcharge should be similar to existing surcharges already approved by the Commission, such as SCE's Historic Procurement Charge (HPC) approved in D.02-07-032 and the Cost

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[52] AB428, Sec. 1 (Legislative intent) as last amended (June 16, 2003) states that:

> "it is the intent of the legislature to *affirm the electrical corporation's obligation to provide* transmission, distribution, and *resource adequacy services* for all customers."

Responsibility Surcharge (CRS) approved by the Commission in, among other decisions, D.03-07-030. TURN also proposes to allow ESPs who have acquired sufficient reserves to "opt-out" of paying this surcharge.

Although the original proposed decision issued in this proceeding advocated the adoption of the TURN approach, PG&E, SCE, and other parties raised several valid implementation issues with TURN's proposal in their comments. These parties' primary concern was that the utilities would be left with the cost of acquiring resources for ESPs that they might not be able to collect from the ESPs, and that it would be difficult to procure resources over a longer time-period if ESPs could "opt-out" of the program on a yearly basis.

While these implementation issues are not insurmountable, and could potentially be resolved through the workshop process, in this decision we have determined that the most simple, most direct, and most efficient approach is that the Commission shall require each LSE to be directly responsible for acquiring their own reserves. As noted, this approach is legally supportable and consistent with the requirements of Pub. Util. Code § 394 (for ESPs) and AB117 (for Community Choice Aggregators).

8. Issues to be Addressed in Workshops

This decision begins the process for the Commission to formalize its resource procurement processes to explain how it will create a resource adequacy framework.

The Joint Recommendation proposes that:

> "The Commission should immediately initiate a parallel process to develop a permanent resource adequacy framework…[and] to initiate a collaborative process to

> develop such a framework and submit a joint report to the Commission no later than January 15, 2004."[53]

The ISO also supported the need for workshops.[54]

On September 22, 2003 an Assigned Commissioner/ALJ Ruling "establishe[d] a workshop process to address the technical details of specific resource adequacy issues" with:

> "[T]he scope of the workshop…confined to the more technical aspects of this issue, namely the issues of how Load Serving Entities (LSEs) forecast demand, and how supply resources should be valued and considered in assessing an LSEs' resource adequacy."[55]

The Ruling envisioned use of a Commission-generated questionnaire, followed by a workshop, with the potential for additional workshops if needed.

In setting the scope of the workshop, the Assigned Commissioner/ALJ Ruling recognized that there were numerous threshold policy issues that the Commission first needed to resolve before it could develop a permanent resource adequacy framework. Many of these issues are addressed in today's decision, including jurisdictional responsibility for resource adequacy, appropriate reserve levels and phase-in period, and treatment of direct access and community aggregation load.

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[53] Joint Recommendation, Section I.8

[54] As the Sept. 22nd Ruling noted: "The ISO, SCE, and the CEC support the need for workshops. These parties preferred the Joint Recommendation's broader scope of issues, accept the more limited scope of workshops proposed by the ALJ, but continue to press for [additional issues]…to be considered. (Ruling, p. 3.)

[55] Assigned Commissioner/ALJ Ruling Establishing a Workshop Related to Resource Adequacy Issues, p. 1

The purpose of the workshop, as reflected in the Ruling, is not to "re-invent the wheel." In developing their procurement plans, the utilities have explicitly engaged in resource adequacy by assessing the availability of resources to meet their expected demand. Additionally, many of the same parties involved in this proceeding have already participated in the CPA's Reserve Rulemaking, the CEC's Integrated Energy Policy Report (IEPR) process, and the Resource Adequacy Working Group (RAWG) process run by the Inter-Agency Working Group[56] on behalf of the ISO. Although these efforts may not have resulted in parties reaching consensus, they have resulted in framing many of the questions that need to be addressed, and the options available for addressing them.

To the extent possible, the workshop also should develop a common approach, or "template" as WPTF calls it, for evaluating each LSE's resource adequacy. While complete consistency between all LSEs' may not be feasible, at a minimum the workshop process should result in common approaches so that decision-makers and interested parties can evaluate and compare resource adequacy both between utilities and between all entities under Commission jurisdiction. Finally, the workshop should ensure that Commission policy preferences on resource loading order are fairly and accurately counted toward the resource adequacy goal.

We now address the specific areas that the workshop is to address.

First, the workshop will provide a forum for parties to better understand, and for the utilities to explain, how their load forecasts are performed and opportunities to improve consistency between the utilities. As

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[56] This group was comprised of representatives of the Commission, CEC, Electricity Oversight Board, CPA, and DWR.

we discussed elsewhere, the utilities should retain the primary responsibility for developing their forecasts. As SCE states, although parties have complained about the lack of consistency of the forecasts, no party has substantively challenged the results of its forecast. As SDG&E states:

> "As a general matter, SDG&E previously explained that there is an unnecessary preoccupation with 'common' or 'perfect' assumptions to be used by the utility in its long-term resource planning. In SDG&E's view, while assumptions clearly need to be reasonable, the more critical piece is the testing of the assumptions to accommodate uncertainty). In the end, the utilities must plan using the best data for their unique circumstances, as they are accountable for the results."[57]

In the workshop it will be necessary to identify the treatment of direct access load and who should be responsible for forecasting it.

With regard to supply resources the primary focus of the workshop should be the "counting" of resources available to meet demand. How resources are counted in large part depends upon the type of resources that are considered.

The treatment of Utility-Retained Generation (URG) appears fairly straightforward, as almost all parties believe it should be based upon some variant of "dependable capacity," although there is no consensus on how to calculate it. A review of the utilities' filing tends to confirm that they have already accounted for, to a large extent, the availability of their URG resources in developing their procurement plan. How the utilities should value their retained generation should be one of the focuses of the workshop.

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[57] SDG&E Reply Brief, p. 15

The treatment of existing and future contracts and how they should be valued in a resource adequacy framework should be another area of focus for the workshop. As previously mentioned, this includes full recognition of the long-term DWR contracts; the criteria under which other contracts should be counted; and, as ARM suggests, "the treatment of ESP firm energy contracts."[58]

Another issue for the workshop, and consistent with the Joint Recommendation, is the criteria to be used for the reliance of the utilities upon the spot capacity and energy markets to meet a portion of their energy needs. As previously mentioned, we want to ensure that to the extent the utilities rely upon this capacity that we can be reasonably sure that this capacity will be available even under adverse conditions.

Finally, the workshop should address how the preferred energy resources that the Commission is planning to rely on to meet its energy needs can be fully valued under a resource adequacy framework. These so-called "soft" resources (i.e., energy efficiency, renewables, demand response) can provide a significant and cost-effective means to reduce capacity needs yet they have proven exceedingly difficult to count towards resource adequacy requirements under the traditional resource adequacy frameworks such as the ISO-run capacity markets in the Eastern United States.

The Joint Recommendation proposes to include these resources in each utilities' resource adequacy framework, proposing that each utilities' peak load requirements, for both planning and operating reserves, be:

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[58] Sept. 22nd Ruling, p. 3

> "reduced to reflect: 1) Energy Efficiency programs with authorized and funded program designs; 2) Additional Energy Efficiency Programs proposed by the IOUs in their resource plans (and approved by the Commission) based upon potential savings estimates; and 3) existing and future Interruptible or Non-Firm Load Programs."

And that:

> "Demand Response Programs consistent with the levels adopted by the Commission in D.03-06-032 should be included in the IOU load forecasts or resource plans."[59]

The Joint Recommendation goes on to propose that methodologies be developed to reflect the value that these programs have in reducing peak demand requirements.[60]

In conducting the workshops and developing a resource adequacy framework, the Commission reiterates its commitment that full value be given to the preferred resources identified in the Energy Action Plan and to the long-term DWR contracts. As PG&E and SDG&E both noted in their preferred plans, for example, they are planning to meet a significant portion of their peak demand through the use of energy efficiency programs. As PG&E notes, in order for it to successfully implement these programs, it needs certainty that this type of soft resource is able to count toward meeting any reserve requirements. Otherwise, as PG&E notes, it is essentially paying twice for reserves, thus undermining much of the benefits of pursuing these energy efficiency measures in the first

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[59] Joint Recommendation I. 6 and I. 7.

[60] "The accounting for all Energy Efficiency programs to meet capacity and reserve requirements shall be subject to corrective feedback from measurement and evaluation of actual impacts compared to expected impacts…" (Joint Recommendation, I.6.)

place. The CEC, in its comments, notes similar concerns, namely that these soft resources, if properly assessed, can act to meet energy needs and reduce needed reserve levels. As the CEC notes, both it and PG&E are committing significant resources to the measurement and evaluation (M&E) aspects of these programs in order to ensure that targeted energy reductions can be verified as actually occurring.

The Joint Parties interested in Distributed Generation raise similar concerns with the treatment of distributed generation resources, and the concern is equally valid for dynamic pricing and demand response programs. For example, SDG&E notes that it is reasonable to include conservative estimates of forecasted demand response programs in preparing its resource plan.

In guiding the workshops, we reiterate our concern that these non-traditional resources be fully and fairly evaluated, and that any resource adequacy framework not unintentionally limit the procurement of these resources or bias resource procurement solely toward generation-only resources. Not counting these type of "soft" resources in the traditional resource adequacy frameworks could result in California having to pay twice for capacity thus limiting the cost-effectiveness of these programs. Collectively, for example, the three utilities are planning to achieve over 1,200 MW of peak load reduction from energy efficiency programs.

Counting these resources towards any resource adequacy framework is also consistent with previous Commission decisions. D.02-10-062 requires that "utilities include in their plans procurement of base-load and intermediate load reductions in the form of energy efficiency"[61] while D.03-06-032 in the Advanced Metering OIR requires the utilities to "include the MW targets for calendar year 2003-2007 in their procurement plans to be filed in R.01-10-024."[62]

The ability to count these resources, under reasonable and realistic parameters, should therefore be addressed in the workshop. In addressing this issue, parties should focus on how the results of other Commission proceedings can be coordinated with the procurement proceeding so that the Commission (and other parties) do not end up evaluating the same programs twice. For example, the Commission, in R.01-08-028 is already examining the effectiveness of the utilities' energy efficiency expenditures.

Issues of deliverability of resources and penalties will also be addressed in the workshop.

Finally, as noted in the Assigned Commissioner/ALJ Ruling:

> "[I]t is premature to address reporting requirements at this time. It is difficult to determine reporting requirements when it is still unclear what exactly it is that is to be reported…Based on the policy guidance given by the Commission in its year-end decision, the results of the workshop and the success of parties in reaching agreement, the Commission will be in a better position to address the issue of how the information will be used. This subject may be appropriate for a follow-on workshop."

[61] D.02-10-062, p. 27.

[62] D.03-06-032, Ordering Paragraph 1c.

The scope and schedule for the workshops will be the subject of a ruling from the Assigned Commissioner or ALJ within 15 days of this decision.

9. Deliverability

In general, the utilities in their filings sought to address the issue of ensuring that the generating resources upon which they plan to rely are deliverable to their systems. As SCE notes, the simulation models it uses take into account general transmission constraints in order to ensure that proposed resource additions can be delivered to the load. Such an approach is reasonable for longer-term planning purposes in identifying and evaluating various resource options to meet demand. As the utilities resource choices become more focused (e.g., selecting a specific plant or transmission path to access a resource), the utilities should provide greater specificity in their showings that such resources are deliverable to loads, including the effect of adverse conditions upon such delivery.

SDG&E, based in large part upon work done by the ISO, offers a more specific example of how resources should be evaluated for deliverability once they become more clearly identified, stating that:

> "In regard to deliverability of potential resource additions internal to the SDG&E LRA that are currently in SDG&E's or the ISO's interconnection queues, we have completed (or are in the process of completing) generation interconnection studies that have been (or will be) reviewed by the ISO pursuant to their established tariff procedures. Furthermore, prior to contractually committing to a capacity purchase from any project in our generation study queue that seeks to meet SDG&E reliability needs, we would complete further deliverability analysis for review by the ISO. For other generic resource additions internal to SDG&E's service area that are not presently in the interconnection queue,

> we have not identified any specific transmission deliverability upgrades in our opening testimony. However, SDG&E intends to develop a transmission plan of service for such resources that will satisfy deliverability requirements. These studies will also be submitted to the ISO for their review. . . .
>
> "Furthermore, . . . it is critical that deliverability of a resource located outside an LRA be determined for both normal and emergency conditions. This is necessary because remote resources that can be scheduled for delivery to an LRA under normal operating conditions may not be deliverable during certain transmission contingencies when they are needed to serve the LRA's reliability needs and vice-versa."

SDG&E's definition is a useful starting point to address deliverability requirements for larger resources.

We are aware of FERC's most recent pricing policy requiring transmission owners to provide a credit to generators for network upgrade costs,[63] which are ultimately paid for my ratepayers. However, we note that in the Eastern ISOs with capacity markets, generators must pay for deliverability upgrades to qualify as an eligible capacity resource. Generators are then compensated for the transmission investment with property rights, such as congestion revenue rights.[64] This is one definition of deliverability for new resources that will be discussed further at the workshops.

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[63] Network upgrades represent reliability or deliverability upgrades to the transmission system beyond the first point of interconnection that would not have been necessary "but for" a particular generator interconnection.

[64] FERC 104 FERC 61,103 Dated July 24, 2003 see paragraphs 754- 756, 767-768. 784 for FERC discussion regarding deliverability of capacity resources, See paragraph 695 for

Footnote continued on next page

We remain concerned that for smaller energy sources that are either located close to load centers, such as distributed generation, or that displace load, such as a broad scale energy efficiency or demand response programs, appropriate deliverability requirements can be developed that will not impose excessive or unreasonable regulatory burdens that deter their use and deployment.

The issue of deliverability is an issue that clearly needs further study and should be addressed in further detail in the utilities' revised long-term plans. Therefore, following the workshop process, we may seek additional comments in the next procurement rulemaking as to how to assess and develop workable deliverability standards.

B. Market Structure for Longer Term Resource Commitments

1. Determining the Need for Resource Commitments

At the March 7, 2003 PHC, clear direction was given 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. In addition, utilities were directed to include provision for customer-owned, as well as utility-owned, distributed generation, and to propose a methodology for weighing the tradeoffs between transmission and generation investments. This prioritization of

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FERC discussion regarding compensation for network upgrades in ISOs and RTOs with Locational Marginal Pricing.

resource additions is consistent with our direction in D.02-10-062 and the loading order of resources stated in the Energy Action Plan.

Our record here supports further policy direction on resource selection. 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.

Next, utilities should increase the degree of diversity of fuel types and sources for the generators serving California electric customers. To the extent it is cost-effective, utilities should be looking to new generation capacity that is not powered by natural gas, currently the prime mover for 42 percent of the electric energy consumed in this state.[65] Options for fuel diversity include: (1) other fossil fuels, i.e., coal or oil, which carry emissions costs risks; (2) Energy Efficiency and Demand Response programs; (3) renewables; and (4) transmission.

The hearing record shows a need for the utilities to commit to new or refurbished generation capacity in the next few years and also provides a fuller discussion in several areas on how that should be done. Therefore, we need to adopt specific rules for how the utilities should acquire long-term resource additions.

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[65] Department of Energy/EIA – 0348 (01) 2 State Electricity Profiles 2001, p. 19, published October 2003.

2. Today's Hybrid Market Structure

California's policy regarding utility ownership and control of power plants has undergone profound changes over the years. Prior to the 1980s, the utilities were entirely in control of their own supplies. With the passage of the Public Utilities Regulatory Policies Act (PURPA) in 1978, California, along with the other states, began to welcome cogeneration in the form of QFs. California began considering proposals to move to a competitive market structure in the 1990s. Under the restructuring process adopted by the legislature in AB 1890, the utilities divested most of their generating plants with the exception of nuclear, hydro, and some remaining fossil capacity. During our state's energy crisis of 2000-2001, new legislation forbade any further divestiture.

Today, at the wholesale level, California's IOUs are primarily relying on short-term energy and capacity products (i.e., less than one-year in term) to meet a substantial portion of their residual net short open positions. A utility's residual net short open position is the result of the utilities' retail load requirement less utility retained generation (URG) resources, existing utility contracts, QF power, and long-term DWR contracts operated under a least-cost dispatch framework. More recently, we are seeing shift towards procurement of longer term contracts (i.e., SCE's Mountainview application and SDG&E's Motion for approval to enter into new resource contracts). There are about 18,000 megawatts (MW) of divested generation in California as well as several newer merchant power plants operating in the WECC region. Jurisdiction over transmission rates and terms of service passed to federal jurisdiction under California's AB 1890 restructuring and is now administered by the California ISO under FERC.

The Commission regulates rates and service for utility retained generation plant and all distribution services, oversees utility procurement practices, oversees Public Goods Charge (PGC) funded energy efficiency and renewable resource programs, and establishes rules for direct access. At the retail level, about 13% of IOU aggregated load is direct access, meaning it is served by competitive energy providers; the ability of new customers to sign up for direct access is precluded by legislation. The utilities are the provider of last resort for all customers within their service territories.

3. Benefits of Utility Ownership v. Benefits of Third-party Contracts

The issue of whether the utilities should own additional generation capacity has been renewed with the resumption of utility procurement. AB 57 takes a neutral position on this issue. In D.02-10-062, we asked the utilities to put forward long-term resource procurement plans that included supply options, and stated that in these plans the utilities should consider both utility owned/retained and merchant generation sources.

In their long-term plan filings on April 15, 2003, no utility proposed owning a new generating plant and only PG&E provided a cost-recovery mechanism proposal for utility ownership of new plant. PG&E proposes the Commission adopt a traditional cost of service ratemaking methodology for utility constructed and owned generation. SCE and SDG&E propose that the utilities consider a mix of generation resources by fuel type and ownership and that the Commission consider the merits of specific projects and cost recovery mechanisms on an individual basis.

Since the long-term plans were filed, SCE and SDG&E have made proposals to purchase and own new generation resources. On July 21, 2003, SCE filed an application for approval of the Mountain View project, a power plant of 1,000 MW capacity that SCE would control through a wholly-owned subsidiary. That project was evaluated and approved with modifications in D.03-12-059. On October 7, 2003, SDG&E filed a motion in the instant proceeding that would, if granted, result in ownership of the Palomar project, a 500 MW generation plant to be constructed for its eventual ownership and control. SDG&E's motion also includes a proposed purchase power agreement (PPA) for the output of the to-be-constructed 500 MW Otay Mesa project and several other smaller PPA contracts.

The CEC's reports show that approximately 5000 MWs of new generation have been permitted in California but not yet built. Many market generators that hold these permits are in severe financial distress and cannot continue construction without long-term supply contracts with the utilities or other load serving entities. There is an opportunity today to acquire additional generation cheaply and, therefore, we should not delay in setting out clear market structure rules.

SDG&E observes that there is increasing interest and discussion of the possibility of a future utility role in ownership of generation, as at least a partial alternative to reliance on purchased power contracts with suppliers and exclusively non-utility ownership of future generation. It states that consideration of this would require clear-cut rules that would support a long-term utility role in serving a stable customer base.

Benefits of utility ownership cited by SDG&E include the stability and permanence of a regulated utility, the ability of the Commission to directly regulate the price, terms and quality of the generation service provided by the utility, the availability of a proven high-quality workforce (both management and labor) to operate and maintain utility generation, and the increased likelihood that such generation would be located within the State of California.

TURN, IEP, and WPTF recommend that the utilities acquire power through an open competitive solicitation process based on formal request for proposals for PPAs with third-party market generators. These parties express concern about the potential for conflicts of interest by the utility, both in the design of the bid solicitation and the evaluation/selection process, and do not recommend that the utilities be able to compete in these solicitations, or if they do, that there be independent administration of the bid preparation and review process. IEP and WPTF also question whether there can be a level playing field if the utilities are allowed to later request cost recovery of any construction overruns under a cost of service ratebase approach.

TURN proposes that while the utility should not be allowed to compete in the competitive solicitation, it should be prepared to build the plant itself if market bids do not provide the lowest cost means. TURN recognizes that the competitive market does not always work as it "should" and the utilities should pursue a "self-help" alternative for meeting their needs as an insurance policy against potential future dysfunctions in long-term markets.

The primary advantage of third-party bids, TURN, IEP, and WPTF state, is that it provides a market standard for the true competitive cost of new generating capacity. This standard is useful primarily in getting the best deal for ratepayers. It is also valuable in providing a proper benchmark against the cost of alternatives to new capacity, such as demand reduction programs and transmission system efficiency enhancements. In addition, it provides a standard against which the costs of existing and future utility-owned generation could be measured.

Third-party developers assert they exist in a competitive environment that is different from the regulated environment of the utilities. They are subject to market discipline and shareholder control to a greater degree than regulated electric utilities. Their mistakes, cost overruns, and the financial consequences of development of resources that are ultimately not feasible or cost-effective are their own. Third-party power plant developers have no incentive to overcapitalize or to build excess capacity. IEP and WPTF state that utilities will have an incentive to overreach because there is a greater probability that their costs can be recovered.

Further, testimony in support of a competitive market indicates that in the case of a PPA contract with a third-party, there can be clear responsibilities and performance obligations and assignment of costs. The holder of a third-party power contract assumes a great deal of risk. Difficulties that arise during the construction of the plant and later, in its operation, can be resolved in a clear manner, and to the extent that ratepayers are to be charged for additional costs, there will be clarity in how they arose and the resolution of the conflict with the third-party generator. A further point made in testimony is that with the utility contracting with itself there is less clarity about where the risk is held, and costs may be shared or shifted onto the utility’s customers.

Several parties assert that by eliminating the utility itself from the competition for new capacity, the number of competitors is reduced, and hence, the degree of competition is reduced. Additional competitors yield greater competition and, as a result, a better outcome for all. However, IEP added that the degree of competition is reduced not only by a reduction in the number of competitors but also by whether the utility itself is a competitor in the bid process. Competition for new generation capacity may be enhanced, not diminished with the utility removed from the competitive process. Allowing the utility to compete to serve itself may result in a bias toward self-dealing or an advantage for the utility's own offerings over those of third-party competitors.

In weighing the arguments on market structure, we find that California should not rely solely on competitive market theory and the behavior of market generators. While market redesign is underway by the ISO and FERC, it is not complete. California has a long history of reliable service being provided by utility-owned and operated generation plant and a recent painful history of rolling blackouts and high price spikes from reliance on third-party generators in a poorly designed competitive market. We agree with SDG&E that a portfolio mix of short-term transactions, new utility-owned plant, and long-term PPAs is optimal, combining the security of generation assets under the full regulatory oversight of the Commission with the flexibility of ten-year contracts, and the potential benefits of operating efficiencies and lower costs from a competitive market. We reference a ten-year PPA based on ORA's recommendation and SDG&E's pending RFP.

We find that designing rules for a hybrid market structure is a complex undertaking. One approach includes a competitive solicitation to be used in order to capture the lowest prices and maximum choices. IEP raises the issue of a level playing field, with the utilities not being able to bid low and then later seek additional cost recovery. The record here shows that the utilities may face challenges when trying to construct new plant as it has been twenty to thirty years since they built fossil-fuel plants. Therefore, the solicitations may request turn-key plants and PPAs with later purchase options rather than initial utility construction.

The presumption that utilities may favor their own capacity at the expense of third-party generators is well founded, with effects in both procurement of power from existing resources and in the procurement of new capacity. In their procurement from existing resources, utilities are monitored for their patterns of dispatch to assure that the operations are undertaken in a least-cost manner (i.e., Standard of Conduct No. 4). The presumption is that without that standard, utilities would favor their own resources at the expense of lower cost available alternatives. The historical relationship of the utilities with QF producers similarly leads to concern that given the choice utilities would rather rely on their own resources than on those that come from the market.

The difficulty in adding to California's generating capacity at all during the years of the Biennial Review Proceeding Update (BRPU) process provides a historical example. IEP asserts that the Mountain View procurement application is an example of SCE being unwilling to participate in a competitive process at all. Whether these operating and capital accumulation biases are real or they are only perceived, the Commission should address them.

Careful design and monitoring of a competitive solicitation process and use of a least-cost dispatch standard are important means of addressing the potential for bias. Another means is to adopt a procurement incentive mechanism, so that the interests of utility investors, management, and ratepayers are better aligned. The utilities have an opportunity to invest and earn a return from generation assets; a similar opportunity for profit should be provided for selecting and managing well all other procurement products. We address this in a later section of this decision.

The utilities also request that the Commission provide assurance that our cost-recovery mechanisms will be reliable and consistent over the long term and that we do not adopt policies that would lead to a less stable customer base wherein investments in generation and long-term power contracting would create significant stranded cost exposure. While some of these issues, such as pending legislation to establish a core-noncore market and to change direct access eligibility, are beyond our ability to address here, we are committed to returning the utilities to financial health and to not adopting any mechanisms that would lead to a deterioration of their creditworthiness.

At same time we provide an opportunity for the utilities to own new generation, we want to provide assurance to the third-party generators that we see a meaningful role for them in California's energy future. Third-party generating capacity, if contracted properly, holds a number of advantages for California ratepayers. Moreover, it is necessary to have a thriving independent generating sector for these advantages to be secured. We recognize the financial duress, manifested in significant debt and credit problems, that has beset the merchant generator community post energy crisis. Some firms have closed shop, others have scaled back their operations. We wish to support depth and liquidity in energy markets and, by not letting them compete, this will shrink the market. If third-party generators come to believe, as a result of Commission decisions or utility actions, that an unfavorable market for their services exists in California, then they may withdraw from our state and concentrate their limited resources elsewhere. We would soon face a shortage of serious independent generators able and willing to bid, construct, and operate productive generating capacity here. California would be left with utility development of new capacity as its only option.

4. Competitive Solicitations

Based on our discussion above, the utilities should rely on the formal RFP process to secure future long-term generating capacity resources. The RFP process, if properly designed, calls forth from the marketplace a wide set of choices for development.

We do acknowledge, however, that the utilities are free to present to us at any time applications for certificates of public convenience and necessity (CPCN) for generation projects that are utility-owned and/or utility-built. By requiring RFPs as a standard procedure for non-utility owned generation resources, we are by no means discouraging utility projects where they are cost-effective and appropriate. However, the Commission does not have a comprehensive methodology available at this time to evaluate such projects against alternatives brought to us through a competitive RFP. Thus, we will consider utility-owned and/or utility-built proposals on a case-by-case basis. Utilities proposing a CPCN should, at the time of application, present evidence and justification for why the utility ownership structure is preferable and how cost containment should be addressed.

WPTF argues for a specific structure for capacity procurement that puts procurement via contract on an equal footing with utility-build options. WPTF's proposal is that prior to its issuance, an RFP must be approved by the Commission or an independent third party to verify that it is not tilted in favor of the utility or its affiliate's bid. Second, bids should be evaluated by an independent third party, such as an accounting firm, consultant, or specially convened review panel. Finally, the third party will select a winning bid which, if it meets the criteria presented in the RFP, the utility must accept.

WPTF's proposal would result in a cumbersome process, and one that would be difficult for any utility to endorse, especially as it reserves final choice of contracting partner to a party other than the utility itself. But its need derives from the perception that without the involvement of independent parties in the development of the RFP, the evaluation of the bids, and the ultimate selection of the winning bidder, the utility would have an incentive to act in ways that would bias the process in favor of itself.

The Commission currently has in place safeguards to address WPTF's concerns. First, each utility has a Procurement Review Group (PRG) that consults with the utility in the design of the RFP and the evaluation of bids. Next, the Commission will review all long-term commitments that result from an RFP through its formal process which allows notice to all parties and an opportunity for public review and comment. Based on our continuing review of the RFP process, we will adopt additional safeguards if we find it is necessary.

WPTF further points out, in its comments on the alternate decision, that generation plant owners may also conduct RFPs, and that it may be beneficial to have the utilities participate in those solicitations. Thus, in response to WPTF's comments on this issue, we grant that additional authority. In particular, we wish to clarify that the utilities are permitted to bid in open seasons or RFPs held by generation owners. The applicable terms of the contracts being offered in the generator RFPs or open seasons need not match precisely the utility authority to conduct their own RFPs. However, the terms should be reasonably similar. To encourage reasonable bidding practices, we encourage the utilities to consult with their PRGs in advance of submitting any bids in generator RFPs or open seasons.

5. Length and Type of Contracts

As ORA's testimony discusses, over reliance on shorter-term energy markets can be dangerous, as in the energy crisis, and also does not ensure reasonable cost and rate stability due to potential resource shortages and increased prices with price spikes. While commitments beyond one to five years will be needed, this does not mean that thirty-year commitments are necessary. ORA testifies that ten-year contracts could provide sufficient assurance for market generators to construct new power plants and five-year contracts could provide generator owners the financial guarantees to invest in emission control equipment and for refurbishing units with the latest technologies.

We agree with ORA and SDG&E that a mix of contract lengths, sufficient to allow for new construction of power plants or transmission projects, is best. We also agree with SDG&E that in evaluating an optimum portfolio mix, consideration needs to be given to existing resources and their terms. We also agree with the City of Chula Vista, which encouraged the Commission to have the utilities fill many of their immediate resource needs with shorter-duration contracts so as to avoid potential stranded costs for Community Choice Aggregation, and we expect the utilities to shape their portfolios accordingly.

Parties discussed types of contracts that could provide the utility increased control and supply reliability. First, with respect to non-unit contingent contracts (i.e., contracts with unspecified resources) with existing resources, ORA proposes that such contracts should be authorized only for less than one-year in term and executed no more than one-year forward. For contracts for existing resources where the utility would have dispatch rights to specified resources, ORA recommends contract language stating that only specific plants could provide the power, and perhaps ancillary services, with no allowance for substitution from the market.

PG&E, in particular, raises concerns in its comments about its ability to buy firm system sales, which come with strong financial protection, as well as its ability to do hydroelectric exchanges and purchases with the Pacific Northwest. The Commission does not want to foreclose seasonal exchanges that benefit the ratepayers or PG&E's ability to tap cheap hydroelectric resources in the Pacific Northwest. As such, the Commission declines to limit utility purchases of non-unit contingent types of contracts. However, we are opposed to utilities' signing any additional non-unit contingent contracts that do not specify delivery point (e.g., the DWR contract with Sempra). Such contracts are not beneficial to providing California with reliable electricity and make more difficult the jobs of the utility dispatching the contract and the ISO dispatching its entire control area. While we would not expect a utility to propose to sign such a contract in the future, we wish to make clear that we will not allow such contracts prospectively.

It is clear from this beginning discussion that considerable additional work and evidentiary record development is needed for the Commission to establish workable and reasonable parameters for portfolio mixes most beneficial for the next five years. The next phase of this procurement effort will address these issues prior to the Commission's approval of a long-term procurement plan for any utility.

6. Affiliate Transactions

a) Existing Moratorium and Standard of Behavior 1

In hearings held in 2002, the Commission considered the issue of transactions with affiliates at considerable length. The assigned Commissioner ruled in the April 2, 2002 Scoping Memo that there should be no transactions with any affiliates of the respondent utilities, not just their own affiliates.

Several parties objected to this broad prohibition in their testimony, stating that this would deprive California of a significant source of generation. Parties that supported a prohibition on affiliate transactions supported only the narrower prohibition of a utility purchasing from its own affiliates. TURN, Aglet, and the Consumers Union submitted testimony and comments discussing the risks inherent in allowing utilities to buy power from their own affiliates within the current holding company structure.

During the hearings, the Commission requested each utility to prepare an exhibit showing electric procurement disallowances made by the Commission during the 17-year period from 1980 to 1996. These exhibits show that there were only a limited number of disallowance decisions in that period, and that the majority of these decisions and dollar adjustments involved affiliate transactions. Recognizing this, and that the current affiliate transaction rules adopted in 1997 were not designed for today's market structure, the Commission adopted a moratorium on PG&E, SCE and SD&E dealing with their own affiliates in procurement transactions, beginning January 1, 2003, to allow for a careful reexamination and appropriate modification of our affiliate rules.[66] (D.02-10-062, p. 49.) We also adopted permanent minimum standards of behavior for the respondent utilities, Standard 1 being:

> "Each utility must conduct all procurement through a competitive process with only arms-length transactions. Transactions involving any self-dealing to the benefit of the utility or an affiliate, directly or indirectly, including transactions involving an unaffiliated third party, are prohibited."

In applications for rehearing on D.02-10-062 and D.02-12-074, PG&E and Sempra raise legal challenges to the moratorium on affiliate transactions and SDG&E and Sempra raise legal challenges to Standard of Behavior #1. In D.03-06-076, the Commission found that the ban on affiliate transactions was properly noticed, jurisdictional, constitutional, violated no federal laws, and the record supported the need for a moratorium on utility procurement from its own affiliates until adequate safeguards are fashioned. Further, the decision states that the issue of adequate safeguards against affiliate abuses in energy procurement is an extremely important issue that can be addressed in the long-term procurement phase of this proceeding or in R.01-01-011.

D.03-06-076 also sustained Standard of Behavior 1 and provided the following clarification:

> "Standard 1 does not preclude the IOUs from entering into 'anonymous' transactions through approved

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[66] The moratorium did not preclude "transactions through the ISO that can be demonstrated to include multiple and anonymous bidders". (See FF21.)

> interstate brokers and exchanges, provided that the solicitation/bidding process is structured so that the identity of the seller is not known to the buyer until agreement is reached, and vice-versa. Under these circumstances, the risk of affiliate transaction abuses is minimal. It is our understanding that most, if not all, of the brokers and exchanges being used by the IOUs already structure the bidding so that it is anonymous. Thus, this standard imposes little, if any, burden on interstate commerce."

b) The 2003 Hearing Record

In hearings held during 2003, the moratorium on affiliate transactions was combined with the issue of utility ownership of new generation for the purpose of testimony and briefs. At hearing, the ALJ also asked witnesses whether there should be different rules for short-term and long-term transactions. Additional questions were asked by the ALJ regarding PG&E's and SDG&E's dealings with other departments within their company and with affiliates.

Of the three IOUs, PG&E and SCE focus their comments on utility ownership and do not directly address the moratorium on affiliate transactions, while SDG&E takes a position on both, the stronger position being that the moratorium on affiliate transactions is unnecessary because current rules are adequate to govern any transaction. Further, SDG&E states that transactions between SoCalGas and SDG&E are not, and should not be, subject to the affiliate transactions moratorium.

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.

TURN states the Commission should extend the ban on affiliate transactions because there still exists the possibility of improper behavior by the IOUs. If the Commission does not extend the ban, then it should require pre-approval of affiliate contracts of more than one year's duration and complete disclosure of all affiliate transactions for procurement from affiliated generators or marketers (i.e., no confidentiality would exist, and the utilities must make the contracts publicly available). TURN also states that the utility risk management committees must not contain non-utility corporate officers and the Commission should direct SDG&E to create a risk management committee that only looks at transactions from the utility, i.e. SDG&E's, perspective.

IEP and WPTF do not object to affiliate transactions, preferring them to direct utility participation in generation bidding. CAC/EPUC testifies that participation by utility affiliates will enhance competition and specifically requests that the Commission lift the ban we adopted in D.93-03-021 on SCE procuring new resources from its QF affiliates. CCC states the Commission should not allow utilities to circumvent the procurement process by entering into special affiliate deals, citing SCE's Mountainview application process.

c) Discussion

In this decision, we are setting the market structure and rules for long-term procurement. We are allowing the utilities to directly participate in owning new generation facilities but recognize that we will need to be vigilant in overseeing that no perceived bias occurs in selecting, or dispatching the resources, especially when the current cost recovery mechanisms favor the rate-based power plants. We include utility participation in order to have the assurance of more state control over resources and an effective check against competitive market manipulations and abuses.

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. The most direct and effective means to avoid any potential conflict of interest is to simply prohibit the transactions.[67] However, we will grandfather already existing contractual relationships with affiliates (e.g., QF contracts) for the life of the existing plant in order to ensure that existing resources with such relationships can continue to serve California. The holding companies and affiliates of each utility should plan for future generation investment to be made outside of the utility's service territory and sold to other load serving entities. Two exceptions we need to address here are the gas storage and transportation transactions that SDG&E needs to conduct with SoCalGas and that PG&E may need to conduct with separate company departments and unregulated affiliates.

[67] SDG&E has a pending motion before us to consider a transaction with a Sempra affiliate, Palomar Energy. That matter has been separately set for hearing and is not addressed here.

d) SDG&E and SoCalGas

SDG&E states that its dealings with its regulated affiliate, SoCalGas, should not be subject to any affiliate transaction rules because SoCalGas is the only provider of natural gas storage and intra-state transportation in Southern California outside SDG&E's service territory and therefore ratepayers receive benefits from these transactions and would be harmed by any restrictions placed on the transactions.

In response to the ALJ's request, SDG&E prepared Exhibits 110C and 132 to describe all procurement transactions that occur between SDG&E and SoCalGas and entered Exhibit 70 to show its risk management committee and the Sempra Energy corporate committees. Exhibit 132 shows that SDG&E purchases transportation and storage services from SoCalGas, for its own procurement as well as an agent for DWR, pursuant to Commission-approved tariffs and filed negotiated rates, as well as pursuant to the 25 "Remedial Measures" adopted as part of the merger between Pacific Enterprises and Enova Corporation (D.98-03-073, Attachment B). Exhibit 110C shows that SDG&E has recommended additional SoCalGas services to DWR.

Exhibit 70 shows (1) that 7 of the 9 members of SDG&E's Electric and Gas Procurement Committee are from Sempra Energy Utilities (SEU), the parent of SoCalGas and SDG&E; (2) Sempra's Energy Risk Management Oversight Committee, the analytical platform supporting enterprise-wide energy risk-management activities, contains members from both the regulated and unregulated affiliates; and (3) Sempra's Project Review Committee, which reviews and approves all transactions in excess of $10 million and commitments with important policy implications, has no members from SDG&E or SoCalGas and only one member from SEU on an 11 member committee.

In 1998, when the Commission approved the merger between Pacific Enterprises and Enova Corporation, California's electric market was under the competitive market structure of AB 1890. The remedial measures adopted then for transactions between SoCalGas and SDG&E should be reexamined in light of today's market structure. For instance, as a condition of approving the merger, the Commission required SDG&E to sell its gas-fired generation plants to non-affiliates of the merged company, a market power mitigation measure sought by FERC and ORA. Today, the Commission is entertaining a proposal from SDG&E to own a Sempra gas-fired generation plant and has placed SDG&E as agent of DWR contracts with gas-fired generation plants.

In addition, as well as adopting the remedial measures in Attachment B referenced by SDG&E, the Commission in D.98-03-073 ordered the hiring of an independent auditor for a management audit of how the combined utilities operated. One of the concerns found by the auditors, and addressed by the Commission in D.02-09-048, was the sharing of SoCalGas risk management information with a Sempra Energy Trading vice president. The audit was conducted between June of l999 and July of 2000.

Even without the benefit of examples of any harm to SDG&E customers from including Sempra personnel, we find that including such people on a committee to evaluate procurement options for the ratepayers is troubling. Sempra officers have a foot on each side of the firewall, partly representing SDG&E's customers, and partly representing the affiliates. To protect the appearance as well as the fact of affiliate separation, we think there should not be affiliate or holding company personnel involved in utility procurement decisions of the utilities.

We are also troubled by SDG&E's procurement risk management committee being dominated by SEU officers. SDG&E has extremely competent management and it is this management whose duties should include assuring that procurement activities are undertaken in the most appropriate and economical manner.

Therefore, we direct that SD&E file a revised Exhibit 70 to reflect that the risk management committee(s) overseeing SDG&E's electric procurement operations and DWR-related gas procurement operations are comprised solely of SDG&E management. This filing should be by Advice Letter within 30 days. We may review this finding after completion of the SDG&E/SoCalGas/SEU audit, as discussed below.

In D.01-09-056, the Commission reviewed Sempra Energy's September 13, 2000 request to reorganize its regulated California utility businesses to further integrate the management and cultures of SoCalGas and SDG&E and found the proposed functions for shared resources to make business sense. SDG&E was not procuring electricity in the market at the time of this filing and decision. A review of whether negotiated transactions with SoCalGas should be subject to special transaction rules and reporting should be undertaken, especially since SoCalGas' services are under an incentive mechanism while neither SDG&E's electric procurement operations nor its DWR related gas procurement are under an incentive mechanism.

The management audit discussed above should be narrowly focused on two issues: SEU's participation in the risk management committee structure for SDG&E procurement operations; and any rules or reporting needed for SDG&E's energy procurement transactions with SoCalGas. The Commission's Energy Division should draft the scope of work required, select an independent auditor, and oversee the analysis. At the conclusion of the analysis, an analysis report should be filed with the Commission and served on all parties to this proceeding. The auditor should remain available to explain the report's findings, and testify in evidentiary hearings at the Commission on the findings included in the report. These audit costs should be reimbursable. SDG&E should place the costs in a memorandum account.

In Resolution (Res.) E-3838, issued on July 10, 2003, the Commission authorized SDG&E's first Gas Supply Plan for its administration of DWR contracts. In that resolution, we apply the affiliate transaction rules to all procurement transactions between SDG&E and SoCalGas, and set an interim standard for transactions SDG&E enters on behalf of DWR with either itself or an affiliate for services which are paid on a negotiated basis. We should adopt this standard on an interim basis for all SDG&E's procurement transactions.

e) PG&E and Affiliates

In Res. E-3825, adopting a Gas Supply Plan (GSP) for PG&E's administration of the gas tolling arrangements of DWR electricity contracts, the Commission expressed concern that PG&E may engage in inappropriate self-dealing with its affiliate or operating divisions and proposed an interim method for addressing it. Specifically, the Commission stated:

> "An additional consideration is the extent that PG&E may engage in inappropriate self dealing with its affiliates or operating divisions. Such abuse is possible since PG&E owns and markets, through its Golden Gate Market Center operation, gas storage (in direct competition with Wild Goose Storage) and intrastate backbone transmission services. As a case in point, PG&E is proposing using parking and lending services with the Golden Gate Market Center under the Gas Supply Plan for managing imbalances. Additionally,

PG&E Gas Transmission Northwest, a pipeline connecting western Canadian gas pipelines to the utility's backbone transmission system is controlled by a utility affiliate."

"In D.02-10-062, we adopted standards of behavior that the utilities' must observe in connection with their procurement practices. For transactions with affiliates, Standard of Behavior No. 1 is applicable and specifies the following:[68] [69]

"Each utility must conduct all procurement through a competitive process with only arms length transactions. Transactions involving any self-dealing to the benefit of the utility or an affiliate, directly or indirectly, including an unaffiliated third party, are prohibited." (D.02-10-062, p. 51, *mimeo.*)

"To the extent that PG&E will consider using a utility affiliate to provide service for the DWR contracts, it must obtain a waiver from this prohibition through a petition to modify D.02-10-062.

"In cases where PG&E is considering use of its utility owned facilities and services, we are concerned about PG&E's ability to engage in earnest negotiations as an agent of DWR for services offered and provided by the

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[68] D.02-10-062, placed a moratorium on SCE, PG&E and SDG&E dealing with their own affiliates in procurement transactions, beginning January 1, 2003, lasting for two years or until the rulemaking is completed, whichever date is first. (See p. 50, *mimeo.*)

[69] D.03-06-067, "Gas Procurement for the utilities' DWR is a hybrid: it should follow the same standards as gas procurement for the utilities' own contracts, yet it is reviewed under a separate Gas Supply Plan, with the review conducted annually in conjunction with DWR contract administration and least-cost dispatch." (See p. 10, *mimeo.*)

utility.[70] In some cases there may be competitive alternatives available to PG&E and that the utility has discretion to use its own facilities or those of another provider (e.g., gas storage). A conflict of interest is inherent in such bargaining because the utility has opposing goals to increase utility profits yet protect the interests of DWR, the principal, and minimize costs. To remedy this conflict, we need a standard to gauge whether PG&E's negotiated prices for these services on behalf of DWR are the product of the competing interests of a buyer and seller in an arm's length transaction. An additional factor for consideration are PG&E's request for offers (RFO) and bids received from competitors to provide services. We expect PG&E to seek such bids in all cases where competitive services are available.

"For PG&E's initial Gas Supply Plan, we will adopt the following presumption of reasonableness standard. We will presume in such cases where an RFO is issued and offers are received that a reasonable price is paid if PG&E's charge to DWR for the use of the utility's facilities or services is the same as or lower than the bid(s) received. In cases where there are no competitive alternatives for comparison, we will presume that a reasonable price is paid if PG&E's charge to DWR for the use of the utility's facilities or services is either: 1) the tariff recourse rate for the service; or 2) if the price is negotiated, no higher than the volume weighted average of the price the utility negotiated (except for DWR) for each similar service in the same month and for the same period the service is provided. PG&E will be required to show why any transaction entered into above the weighted average price level was appropriate

[70] In some instances PG&E's tariff allows the utility to negotiate prices with their customers for certain services (e.g., parking and lending).

> and reasonable. Whether the utility's decision to use such services was prudent will be considered in our reasonableness review." (Res. E-3825, issued July 10, 2003, pp. 18-20.)

The concerns raised in Res. E-3825 apply beyond the GSP to include future electricity procurement by PG&E for its own portfolio. We should establish rules for any dealings with PG&E Gas Transmission Northwest if PG&E needs to deal with this affiliate in order to access Canadian gas pipelines. In cases where PG&E is using its own facilities, we have the same concern with negotiated rates that we discuss earlier for SDG&E and also question whether the limited competitive market for storage services is an appropriate benchmark or whether a cost-based standard should be developed. For dealings with other departments, we should examine any potential for abuse due to different department's costs recovery mechanisms and incentive structures. Therefore, we direct a management audit focused on these procurement issues be undertaken, using the same procedure we specify above for the management audit of SDG&E again, these audit costs are reimbursable; PG&E should place the costs in a memorandum account.

In summary, we adopt here a permanent ban on affiliate transactions for procurement with the following exceptions:

1. "Anonymous" transactions through approved interstate brokers and exchanges, provided that the solicitation / bidding process is structured so that the identity of the seller is not known to the buyer until agreement is reached, and vice-versa.
2. Transactions for natural gas services between SDG&E and SoCalGas and between PG&E and affiliates and operating divisions that are found necessary and beneficial for ratepayer interests. These transactions should be subject to the rules

adopted in Res. E-3838 and Res. E-3825 pending receipt and review of the management audits ordered here.

3. Grandfathering of already existing contractual relationships with affiliates (e.g., QF contracts) for the life of the plant.

C. Financial Capabilities of the Utilities

Each utility's long-term plan shows a need for additional supply-side resources within the next five years, but PG&E's and SCE's recommended plans rely solely on short and medium term contracts to meet their needs, rather than proposing commitments to new or repowered power plants. Both utilities cite their inability to access the capital market at reasonable rates and the need for maximum flexibility due to the lack of clear resolution on the critical issues of direct access policy, community aggregation, and prospects for a core/noncore market structure, as the reasons they are unwilling to make longer term commitments. ORA testifies that PG&E's and SCE's recommended plans rely too much on market purchases and may not have adequate resources to meet their customers' need.

In D.02-10-062, we addressed the utilities' capability to meet their obligation to serve, and found that PG&E and SCE did not need to obtain an investment grade credit rating prior to resuming the procurement role. We addressed each of the arguments raised by PG&E and SCE regarding why they were not capable of resuming full procurement. We found that PG&E and SCE were capable of resuming full procurement and, under their continuing obligation to serve, should do so beginning on January 1, 2003.

Today, the three utilities have all successfully resumed full procurement and the financial prognosis for PG&E and SCE is much improved. SCE has received an investment grade credit rating from S&P, Moody's and

Fitch. On December 18, 2003, PG&E and the Commission reached a Modified Settlement Agreement (MSA) which according to PG&E, "paves the way for the utility to emerge from Chapter 11 as an investment grade company…."[71] On December 19, S&P indicated that it would place PG&E's current "D" grade[72] credit rating on its CreditWatch listing, "with positive implications."[73] On December 23, Moody's upgraded PG&E's rating to Ba2, two notches below investment-grade. Bolstered by these recent developments, and with financial metrics improved, we expect each utility to make the investments necessary to meet their obligation to serve their customers at just and reasonable rates.

The uncertainties surrounding direct access policy and the legislature's consideration of core/noncore market structure make procurement planning challenging, especially for long-term commitments. PG&E provided a core/noncore scenario to guide its planning and other utilities should consider this in their next plan filing. We agree with the utilities and other interested parties that care should be taken not to make commitments that could later result in stranded costs. For their next long-term plan filings, all three utilities should include an appropriate level of long-term commitment to additional power plants or plant-specific purchase power contracts.

SCE and SDG&E now have investment-grade credit ratings, and PG&E expects to return to investment-grade status soon. The utilities are concerned with the financial and credit implications of any long-term power contracts they

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[71] PG&E News Release, December 18, 2003.

[72] Current rating is three notches below investment-grade.

[73] CreditWatch, December 19, 2003.

may enter into, particular as it affects their long-term prospects of maintaining commercial viability. SCE and PG&E provided most of the testimony on debt equivalency, credit capacity and collateral issues. SCE cites the debt equivalency issue and lack of Commission policy on cost recovery issues as barriers to their entering into long-term contracts, while PG&E focuses more on credit capacity and collateral issues.

1. Debt Equivalency

Given the Commission's policy objective of encouraging the IOUs to enter into at least some longer-term PPAs, we now turn our attention to the issue of debt equivalency. Debt equivalency is a term used by credit analysts for treating long-term non-debt obligations, such as PPAs, leases, or other contracts, as if they were debt, in assessing an entity's debt-equity ratio. Credit analysts may adjust a utility's balance sheet and income statement entries by assigning a debt equivalence amount (in dollars), expressed as the net present value of a PPA's capacity payments, multiplied by a "risk factor." The risk factor can be 0% to 100% of these contractual payments, depending on the type of obligation. The adjusted financial information is used to calculate the financial measures that are part of assessing a utility's credit quality.

a) SCE's Concerns for Long-Term Power Contracts

SCE has now received investment-grade credit ratings from all three rating agencies. SCE asks that the Commission take steps to maintain the utility's creditworthiness and financial viability. SCE states that being creditworthy is a prerequisite to implementing its long-term procurement plan. In support of its argument, it cites the 2001 Settlement Agreement in which the

Commission recognized the importance of SCE regaining creditworthiness as soon as possible, so as to provide reliable electric service.

SCE states that as it takes on additional power contracts and other long-term commitments, its credit rating will decline, undermining its ability to maintain its investment-grade status. To counter this rating decline, SCE asserts that the Commission should add more equity to its capital structure, thereby recognizing debt equivalency costs in rates as well as in overall costs of procurement.

b) Implications for Market Structure

SCE testifies that the rating agencies are looking for the longer-term solution to the market structure problem in California, and will only allow an investment-grade rating once they are comfortable that a permanent framework is in place and that it works well in the long term.

ORA counters SCE's position, stating: "SCE's current credit rating reflects the state of the regional electricity industry coming out of the electricity crisis, and cannot be blamed on the Commission's cost recovery mechanisms or the debt equivalence impact of long-term contracts with any degree of certainty."[74] Credit ratings upgrades often occur due to improvements in general economic, industry, or company-specific conditions, rather than to a single issue deliberated by the Commission.

For example, we look at the Commission's recent decision of December 18, 2003, approving the MSA which underpins PG&E's plan for emergence from bankruptcy. On December 23, 2003, Moody's upgraded PG&E's

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[74] ORA OB, p. 9.

credit rating three notches, from B2 to Ba2. Two factors seem to have influenced the upgrade: (1) the settlement allows PG&E a timely exit from bankruptcy; and (2) the company had a strong pre-settlement cash position (as of 10/31/200), equivalent to $4.1 billion.[75]

S&P is reviewing PG&E's credit rating, citing three factors which would influence their determination: (1) the assessment of the MSA and its financial implications for PG&E; (2) the utility's ability to support expenses of its parent company; and (3) debt equivalency related to current and expected long-term contracts.

c) Commission Procurement Policy and Treatment of Debt Equivalency

Preliminarily, we note that AB57 (as per Public Utilities Code Section 454.5(a)(b)(1)) requires "an assessment of the price risk associated with the electrical corporation's portfolio, including any utility-retained generation, existing power purchase and exchange contracts, and proposed contracts or purchases." Thus we take the emerging issue of debt equivalency, and its potential impact on the utilities' financial viability to serve its customers, quite seriously.

We also note that the debt equivalency issue has gained prominence recently, and we wish to examine its impact on utilities carefully. It appears that the three rating agencies have varying methodologies for assessing debt equivalency and there is some subjectivity in this process which is not transparent, adding to the difficulty of this assessment by the Commission. In

[75] Moody's Global Credit Research: Opinion Update, December 28, 2003.

addition, we note that debt equivalency is only one of the many factors affecting a utility's credit rating and therefore its cost of borrowing.

Nonetheless, SCE's concern with this issue is warranted, and we intend to examine it carefully. However, this proceeding is primarily concerned with setting overall policy for resource procurement, and not addressing capital costs for utility investments owing to debt-equity ratios or credit ratings. The more appropriate venue for handling the potential costs associated with additional debt equivalency attributed to a utility for its PPAs is in each utility's cost of capital proceeding. (See D.92-11-049 and D.93-12-022). Therefore, the utilities should present detailed evidence about the treatment of debt equivalency by the rating agencies in their upcoming cost of capital filings. The Commission will consider these issues therein and develop a more robust evidentiary record on this subject before reaching a conclusion based on each utility's unique financial situation.

2. Cost of Collateral

The long-term power contracts that utilities will enter into must be supported by collateral. PG&E and SCE state that their ability to secure reasonably priced financing for these contracts was hindered because of (1) SCE's non-investment-grade rating and (2) PG&E's bankruptcy status. Given their financial duress, each argues that their financial status precludes them from committing to long-term contracts and limits the procurement options available to them. With SCE's return to investment-grade status and PG&E's recent Modified Settlement Agreement (MSA) approved by the Commission, we find no financial barrier which would preclude long-term procurement.

SCE asks that the Commission take steps to maintain its creditworthiness and financial viability by recognizing the costs associated with collateral requirements. It indicates that the ERRA proceeding is the appropriate forum for addressing the impact and treatment of collateral costs; the cost of capital proceeding is the first forum SCE should raise this issue.

PG&E states that its procurement-related credit capacity is capped by a dollar limit as per the terms of its Reorganization Plan. Given these limitations, it does not expect to be able to enter into long-term contracts. We expect PG&E and SCE to revise their collateral estimates (if needed) to reflect changes in its financial capacity now enabled by the MSA and the return to investment-grade status, respectively.

With respect to the administration of the DWR long-term contracts the Commission authorized the three IOUs to serve as limited agents for DWR for fuel management services. PG&E states in its 2004 procurement plan that:

> "DWR is currently arranging [for gas hedging for the DWR contracts] and would continue to do so under PG&E's proposed gas supply plan. However, to the extent that DWR fails to continue to hedge gas prices under its contracts, it is likely PG&E would not have sufficient credit capacity to enter into such hedges given the other demands for its limited credit capacity. PG&E, therefore, requests that the Commission relieve PG&E of any responsibility to hedge gas on behalf of DWR to the extent PG&E's collateral requirements associated with such hedges, in combination with other procurement-related collateral requirements would exceed PG&E's ability to provide such collateral."

The utilities suggest other approaches to dealing with limited credit capacity. PG&E states that the Commission can increase the utility's available credit capacity by increasing the authorized rate of return, by improving various cost recovery mechanisms to limit overall business risk, and by providing for stable decision-making. The Commission's policy for assessing the utilities' financial capabilities may consider issues which affect capital structure in tandem with those affecting immediate cash needs. Moreover, we note that there are elements of credit risk related to collateral issues which transcend cash requirements. Addressing these issues in a single proceeding will better ensure that cohesive policy measures are established.

Finally, we note the positive reaction from credit rating agencies (credit upgrade) to the MSA, which enables PG&E to exit from bankruptcy. In our earlier discussion of debt equivalency, we referred issues affecting utilities' capital structure to the Cost of Capital proceeding. We reiterate that position here.

It is essential to balance the cost of collateral against the risk of counterparty default. SCE has recently regained its investment grade credit ratings. PG&E will soon emerge from bankruptcy, and it expects to regain its investment-grade rating shortly. One possible solution is to focus on transacting with investment grade counterparties, without collateral support. As a general rule of thumb, companies seek to limit their credit/counterparty exposure by primarily transacting with creditworthy counterparties and/or by requiring counterparties to post collateral. We note that should exposure exceed a predetermined limit or a counterparty fail to supply energy when required, ratepayers will suffer the consequences.

The Commission recognizes the dearth of financially stable and viable trading counterparties in the market, as well as credit contraction in the industry, and the implications of these conditions on each utility's credit policy. Nonetheless, we must act on behalf of ratepayers to protect them from the adverse impact of counterparty non-performance, as it relates to cost exposure and/or lack of reliable supply. With respect to unsecured credit limits, when dealing with non-investment counterparties, the Commission insists that as a first option, utilities explore the use of credit mechanisms such as parent company or third party guarantees, letters of credit, surety bonds, etc. The credit assessment should rely on master agreements with special parent and or guarantor provisions for posting collateral and for assuring continuity of service. When dealing with investment-grade counterparties, we approve of the credit thresholds proposed by the utilities. Credit criteria for non-guaranteed government entities are approved, according to the guidelines proposed by each IOU.

V. Long-Term Planning Assumptions and Policy Guidance

A. Utilities' Current Filings

1. Parties Positions

On April 15, 2003, the respondent utilities filed long-term resource plans presenting their estimates of resource needs and how they plan to fill those needs over the years out to 2023. The plans provide basic information about the expected load growth in the utilities' service areas and the resources that will be required to meet that load. Each utility reminded the Commission of the policy issues it considers outstanding that make long-term resource planning difficult.

The utilities' plans are different from one another in style and substance, but on one point they all agree: It is difficult to make long-term plans in the absence of certainty, particularly certainty regarding future Commission policy on such issues as Direct Access. The utilities raised other issues that inhibit their ability to contract or to make long term commitments, including the lack of creditworthiness.

ORA conducted a comprehensive review of the utilities plans, including employing a consultant, Electric Power Group, to analyze and report on the resource plans. ORA states that the long-term plans represent the first significant effort in over a decade for the Commission to review the utilities' forecasts of demand and supply in a statewide planning context. It finds that the plans are voluminous, complex, and should be viewed as works-in-progress.

ORA testifies that the utilities present primarily broad generalities of their need assessments and generic options for meeting them; further, the utilities do not present specific objectives for meeting their long-term resource needs. A procurement planning proceeding, ORA asserts, should set concrete goals based on specific assumptions that can generally be relied on to evaluate the utilities anticipated procurement filing applications for resource needs and addition. ORA also notes that the utilities' fuel price forecasts were out of date, and that actual gas prices were higher than expected. Through its expert witnesses, ORA provides a number of specific criticisms of individual utility long-term plans.

TURN's position is that the utilities should submit updated long-term plans early next year and that the plans should be approved before they are implemented. TURN makes a number of comments about the utilities' long-term plans, including a statement that they are inadequate to serve as a basis for long-term resource adequacy planning. TURN argues that the utilities should be required to use standardized load forecasting methodologies, and, in the future the CEC should take charge of developing load forecasts for the state. TURN notes that the utilities' fuel and price forecasts were already outdated by the time of their submittal and recommends that the utilities should be ordered to consider specific high-price gas scenarios.

Similar to the utilities' stated position, TURN is concerned that there are certain planning variables the utilities and the Commission must face before they can plan for the future with full confidence. TURN notes a significant increase or decrease in DA customers or market distortions causing DA load to return to bundled service; the potential creation of core and noncore classes; and progress in Community Aggregation. Any one of these scenarios, TURN notes, may cause a utility's long-term plans to become sub-optimal for ratepayers.

The CEC's testimony focuses on strengthening the integration of transmission and generation planning, creating and adopting a resource adequacy framework, and placing the CEC's Integrated Energy Policy Report (IEPR) process at the center of the utilities' procurement planning. CEC states that pursuant to Public Resources Code 25302(f), the Commission is to use the CEC's IEPR "information and analyses" in its own proceedings, unless it has a "reasonable objection" to justify an alternative. CEC proposes that the IEPR information should be used as the base case for all resource planning assessments, demand forecasts and fuel analyses that project more than two years into the future, and for any identification of residual net short (RNS) positions motivating contractual and market purchase activities.[76]

WPTF proposes a common framework or standard template for utility procurement plans to facilitate plan comparison and to evaluate the assumptions across the utilities even if the details remain confidential. This framework, it asserts, would result in a clearer understanding of resource adequacy and system reliability. WPTF agrees with other parties that policy

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[76] Opening Brief, pp. 1-4.

uncertainties, including the future of DA customers and load, contribute to the difficulty of utilities (and LSEs) in planning.

The utilities, ORA, TURN, and CEC also, as part of their Joint Recommendation, propose to revise the long-term procurement plans in 2004 and for the IOUs to submit their revised plans for approval by the Commission by the end of 2004. Parties to the Joint Recommendation agree that any specific long-term commitments made before this process is complete should satisfy the "no regrets" criteria proposed by the CEC or be a resource needed for local grid reliability.

2. Discussion

As stated in D.02-10-062, we intend that the long-term plans of the utilities be the primary vehicles for their decision-making, planning, and procurement. AB 1890's over-reliance on the short-term PX market is a failed system. To ensure reliable service at just and reasonable rates, the Commission must ensure that the IOUs develop and implement sound long- term procurement plans and longer term resource acquisitions. Long-term plans that provide solid information in appropriate detail, and that are reviewed and approved by this Commission, can provide the basis for confidence on the part of consumers, of utility managers, of investors, and of the financial community upon which the utilities depend for capital.

We agree with the utilities, ORA, TURN, and CEC that revised long term plans should be submitted and approved in 2004 and that any long-term commitments brought to the Commission in the interim should meet a "no regrets" criterion. However, in D.03-12-062 we authorized procurement only for the year 2004, based on the utilities' short-term forecasts. We see a gap that needs to be filled so that during 2004 utilities may begin the normal cycle for procuring products required for 2005, in particular for the summer peak. While we will finish that review before the end of the year, most probably within the fourth quarter, the utilities may need this authority in advance of that time. Therefore, we will extend the authority for the utilities to procure contained in the 2004 short-term plans adopted in D.03-12-062, with one revision, to the first three quarters of 2005. This should allow the utilities to being their planning and buying for their needs in advance of the 2005 summer peak.

The utilities are directed to provide updated forecasts of 2005 open positions by compliance advice letter within 30 days of the effective date of this order. These advice letter filings will be subject to prompt Commission review and public comment and will be voted upon by the Commission, in order to comply with the requirements of AB 57. The authority granted in D.03-12-062 allows the utilities to buy for their needs in 2004, and, if advantageous, to buy for their 2004 need level as much as five years out. We leave this authority unchanged. For 2005, we limit the purchase authority to short-term contracts, that is, contracts of one year or less duration.

Returning to the issue of long-term resources, we have addressed the resource adequacy framework these plans should reflect in an earlier section and here we will discuss other refinements needed and set a procedural schedule for 2004.

The CEC's testimony states:

> "…while the process focused on the long term continues, the CEC recommends that the Utility Distribution Companies (UDCs) be authorized to continue procurement using 2003 rules as modified by a decision pertaining to the 2004 short-term procurement plans filed in May.
>
> "In addition, to the extent that a 'no regrets' perspective can lead to selective long-term commitments, some long-term commitments may be acceptable. In this context a 'no regrets' perspective might mean allowing some resource additions that are highly cost-effective under any circumstance; requiring that specific resource additions be more flexible than would otherwise be required; contract terms that allow the UDC to void the agreement under various predefined triggering conditions; etc. What is unfortunate is that it will be very difficult to avoid ad hoc decisions that a particular proposed resource is 'good enough' when a thorough review of the options and the risks they mitigate or exacerbate will be impossible. Without the criteria of a framework, there is no basis for evaluating alternatives." (Exhibit 49, pp. 9-10.)

Any long-term commitments brought to the Commission prior to adoption of the revised 2004 long-term plans should be reviewed within the context of the April filed plans and should make the "no regrets" showing required above. We share the concerns of the utilities, ratepayer interest groups, and market generators and retailers that with current legislation pending on Direct Access and a Core/Noncore market structure, as well as the prospect of departing load resulting from community choice aggregation under AB 117, the utilities should be careful to avoid the possibility of making long-term commitments that could become "stranded costs."

The primary focus in this decision is to guide the utilities in what we expect from them in their revised long-term plans. The first issue is the planning horizon. Several parties discuss the ISO's transmission planning process, which has a ten-year horizon. TURN recommends a ten-year planning horizon here based on estimates to allow a four-year lead time to build a power plant in California and have it in-service, and then to provide the Commission and others adequate time to evaluate resource needs and the best means to meet them.

We agree with TURN that a ten-year procurement planning horizon is appropriate and should provide relatively long notice to all industry players of the state's anticipated needs and allow them to respond appropriately.

Next, we address the level of specificity the plans should contain. ORA's concern that the utilities were overly broad and general in their long-term plans and without specific information is well taken. Though it is not appropriate for utilities to specify in detail the placement of new generation facilities that they may not need to contract for until years pass, or the specific beginning and endpoints for new transmission facilities, it is appropriate that they be more specific than they were in the submitted plans.

The utilities should begin their analysis of their needs by relying on the information and analysis contained in the CEC's Integrated Energy Policy Report (IEPR) and should incorporate that information to form a base case. If a utility does not find it appropriate to use the IEPR results as its base case, it should include an IEPR case along with its more appropriate base case. The utility should explain the reasons for not adopting the IEPR case as its base case and should state how and why the assumptions underlying its base case differ from those of the IEPR. The utilities themselves are the ones responsible and accountable for meeting the loads and energy requirements of the customers in their service areas. The utilities, not the CEC, are required to meet an obligation to serve under several sections of the Pub. Util. Code. We specifically cite here Section 451's requirement to "furnish adequate, efficient, just, and reasonable service … necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." Therefore, regulatory clarity and appropriate placement of responsibility requires that the utilities should have the responsibility of estimating their own future needs.

The utilities should prepare long-term plans based on the outcome of the issues to be addressed in workshops regarding resource adequacy. If those issues are not settled by the time the utilities need to begin their planning, they should make their best estimate of the outcome of the workshop process and estimate needs accordingly.

The long-term plans should provide a range of estimates of future needs taking into account short-term and long-term drivers of need. The long-term plans should include expected load and energy requirements, not only at their expected, or median, levels, but also at the 95^{th} percentile (that is, the one-in-twenty years case) of expected need levels. We also expect the utilities to continue to consider a core/non-core scenario in their forecasts. The utilities should also supply a range of forecasts of load in their revised 2004 long-term plans in order to account for potential changes in community choice aggregation and direct access. This should include forecasts for a scenario involving the resumption of direct access and a separate scenario modeling widespread adoption of community choice aggregation.

The long-term procurement plans should include a mix of all of the resources and products authorized in this decision and in D.03-12-062, with a policy priority given to specific resources, as discussed in the following section.

Specifically, in Section V.B, we discuss integrating specific types of resources into procurement plans in the order stated in the Energy Action Plan. As part of their long-term plans, the utilities should identify which procurement proposals will require environmental review, special permits, separate applications, or other regulatory procedures or proceedings.

The federal and state legislatures, the Federal Energy Regulatory Commission, and this Commission have set a number of criteria through which utilities are to meet their obligations to their customers. The cogeneration requirements of the Public Utilities Regulatory and Policies Act of 1978 and their implementation by this Commission here in California, the renewable portfolio standard, mandated under SB 1078 and SB 1038 and implemented in this docket, the funding of efficiency programs and mandating of efficiency targets, and the Energy Action Plan's preferred loading order, to name but a few, place the utilities in the position of having less discretion than in the past in determining the best combination of resources with which to meet the needs of their customers and of the state. Therefore, the work of the utilities in forming long-term plans is less a matter of Integrated Resource Planning under generalized criteria using a proverbial "clean sheet of paper" than it is a process of "filling in the boxes" to satisfy requirements that have been set up by others. All of those requirements are mandated in the interest of those same customers and residents of California and of the United States. But the process of meeting them may appear less elegant than if the plans were developed de novo. We recognize that a completely fresh set of evaluations of the costs and benefits of different resource options could yield a different set of results than California's current set of policy preferences and legislative mandates.

We use the term "integration" to refer to the utilities' efforts to incorporate various instruments into the energy system planning process – energy conservation and efficiency measures, demand-side management and renewable energy resources are perhaps the most prominent – to enable us to achieve our policy goals of sustainable, reliable and reasonably priced energy service in ways that limit the environmental consequences of the supply process. The CEC also refers to an "integrated" planning process in its Integrated Energy Policy Report. However, our efforts to-date are only initial steps on the road to developing integrated resource plans. What we have accomplished up to this point might be more accurately characterized as "aggregation"—through the Energy Action Plan and our decisions in this docket, we have asked each utility to apply a "loading order" to its resource additions, favoring energy efficiency and conservation, followed by renewable and distributed generation and then relatively cleaner gas-fired central station plants. In effect, the utilities have identified prospective resource additions that fit in each of these categories and gathered them into a bouquet.

While this process has been consistent with our statewide goals for energy efficiency and renewables, it does not end our efforts to promote better-informed, more accountable utility planning. 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 renewables, and adjust the plan as needed to serve those broader needs.

By relying on such a bottoms-up approach, the utility would be able to understand the implications of its planning decisions. The Commission and utilities would be able 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.

We encourage the utilities to begin designing and creating the internal processes necessary to support this type of analysis and will further explore its implementation in our new long-term procurement proceeding.

The long-term plans should include not only the utilities' preferred portfolio choice for how to meet their needs, but also other portfolio alternatives/ variations to meet those needs. We found SDG&E's plan, supplemented by confidential work papers, to be the most helpful in this regard. SDG&E presented its preferred "balanced" plan along with three others reflecting differing expectations about the desirability of in-service-area generation, new transmission, and different fuel types. SCE presented two "what-if" scenarios based on increased gas reliance and reduced gas reliance in addition to its preferred resource plan.

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. ORA and TURN raise an important issue regarding the use of forecast prices in long-term plans. Fuel prices are notoriously volatile, especially on a short-term basis. They vary with changes in the economy, changes in hydro conditions, changes in drilling and pipeline conditions. They vary for other reasons that are sometimes understandable only in retrospect if at all. 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 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.

The utilities should present estimated ratepayer costs associated with each method of meeting their needs, and should include some metric of the variability of those costs. SDG&E presented potential costs at the mean and at several different percentile cut-offs in the total distribution, up to the 98th percentile. We find this to be very helpful and request that the utilities include at least the 90th and 95th percentile projections in their reports. A standardized method of reporting costs is the Present Value Revenue Requirement as discussed in the testimony of SDG&E's Robert Anderson. This provides an objective tool for making cost comparisons.

The following table presents a summary of the dimensions of the information that should be presented in the long-term plans of the utilities:

Load Scenarios	CEC-IEPR Case – Base Case
	Alternative Base Case
	High Load Case (95th Percentile)
	Community Choice Aggregation (CCA)
	Core/Noncore Load Case
	Other Load Forecast Cases
Portfolio Choice	Preferred Mix of Assets including a mix of all of the resources and products authorized in this decision according to EAP loading order
	Other Portfolio options as appropriate
Cost Level	Expected Cost Level
	Cost estimated at 95th percentile
	Other cost estimates as appropriate

It should be understood that filing a long-term plan and having it approved by this Commission does not supplant the requirements for the individual authorizations and traditional procedures for actions that would normally require such procedures. For example, all long-term acquisitions of generating resources should be filed by application and, in the case of utility ownership of a new plant, the utility must apply for a Certificate of Public convenience and Necessity (CPC&N). Likewise, our approval of a plan that calls for the construction or upgrade of transmission capacity does not authorize the construction or upgrade itself. As discussed in a following section, while the

Commission is moving to streamline its transmission review procedures, the utility must still apply for a CPC&N.

We plan to review the revised long-term procurement plans through a full evidentiary process that will conclude with a final Commission decision by end of 2004. We plan to finish this well before the end of the year to avoid the end of the year crunch that has occurred in this proceeding in the last two years. To achieve this undertaking, we will schedule an April 2004 PHC as an early status check. In preparation for the PHC, the utilities should file by the end of March 2004 a working outline of their long-term plans that includes the level of detail and specific scenarios addressed in this decision, the means by which they will incorporate the resource adequacy framework developed through workshops, and a showing that the material provided in the public filing will allow for meaningful participation by all parties; interested parties may file comments on the outlines by mid April 2004. The exact dates will be determined in a subsequent ruling from the assigned ALJ. The revised 2004 long-term plans and the results of the workshops described herein will be reviewed in a new procurement-related OIR, which we will open in the first quarter of 2004.

B. Integrated Approach

We address here the policy each utility should follow in integrating specific types of resources into their procurement plans. Guiding our discussion is the “loading order” set forth in our Energy Action Plan:

> “The Action Plan envisions a ‘loading order’ of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met

> first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to 'get to scale,' the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation."

1. Energy Efficiency

In general, we find that the utilities have taken a credible first step in their short-term plans, which we approved in D.03-12-062, in beginning to capture the energy efficiency potential available in their service territories. In those plans, we authorized utility energy efficiency activities, including the following: establishment of utility funding levels for energy efficiency activities for a two-year interim period, 2004-2005, to coincide with the two-year interim planning horizon for efficiency programs in R.01-08-028; program evaluation and selection criteria, submission timelines and proposal submission directives; a cost-recovery accounting mechanism and customer non-bypassable surcharge to fund procurement related energy efficiency programs; and a decision to shift deliberations on a potential performance incentives for procurement efficiency activities to R.01-08-028.

Though we authorized short-term funding and addressed several other issues in D.03-12-062, we are nonetheless mindful of the tremendous potential for efficiency savings that the utilities have left untouched in their proposed plans and we look to the utilities to significantly enhance their energy efficiency procurement activities in future updates to long- and short-term plans. For the present, utilities will need to "ramp-up" their efforts, to prepare for even more vigorous procurement related energy efficiency activities in the years ahead.

Furthermore, we note that each utility has used a somewhat different methodological approach to analyzing and integrating the energy efficiency component of their procurement efforts into their long-term plans. While we do not intend in this decision to proscribe a set format for each utilities' analysis of the potential for energy efficiency in their service territories and the relationship of that potential to meeting their overall resource needs -- we do urge the three utilities to come together to decide on a common approach to integrating energy efficiency procurement activities into their overall procurement forecasts and resource acquisition strategies. Such an approach will ensure future consistency in Commission evaluation of procurement related energy efficiency efforts.

We address here key procedural and coordination issues related to the Commission's Energy Efficiency Rulemaking 01-08-028. In D.03-12-062, the Commission determined that issues related to performance incentives for energy efficiency would best be able to be deliberated upon and resolved in R.01-08-028. Here, we identify several other issues that the Commission determines are able best to be decided in an integrated fashion in R.01-08-028 rather than in this rulemaking. These include the following: efficiency program duration and cycles, program level evaluations, goals for the Commission's portfolio of energy efficiency programs, future administration of energy efficiency programs, question relating to our preference that be permitted non-utility filings for procurement related energy efficiency activities.

In this decision, we also provide guidance on key issues related to the energy efficiency component of utility long-term plans, including the following: the need for utilities to account for energy savings in their territories from non-utility providers; and the issue of utility accounting for any future potential CO_2 emission penalties in their cost-benefit assessments of project costs to ensure that ratepayers do not bear the burden of such future costs. We also address several technical issues related to the need for utilities to: (a) ensure that the amount of savings projected in procurement related programmatic energy efficiency submissions in R.01-08-028 are equal to or greater than the energy savings and demand reductions forecasted in utility long-term plan forecasts; and (b) ensure that the methodologies and projections used by utility long-term plan forecasters be made consistent with or equivalent to, the savings projected by utility program planners/designers in their program level energy savings submissions to the Commission in R.01-08-028.

a) Procedural Issues Related to Efficiency Rulemaking 01-08-028

Energy efficiency activities initiated in this procurement proceeding need to be closely coordinated with efforts underway in the commission's energy efficiency rulemaking, R.01-08-028. This is the case not only for this decision round, but also for future Commission deliberation on efficiency policy in both R.01-08-024 and R.01-10-028. Below we address a series of current "crossover" procedural issues and provide guidance concerning the future disposition of these issues.

(1) Program Duration and Cycles

As we stated above, we seek consistency in the portfolio of energy efficiency programs authorized by the Commission. This consistency applies to the question of the duration and programs and future cycles of energy efficiency program efforts. In R.01-08-028, the Commission adopted a two-year interim cycle for energy efficiency programs funded through the PGC mechanism. In our proceeding, we have followed this model and order utilities to present procurement related incremental energy efficiency proposals to the Commission for the same two-year interim period. Many parties addressed the subject of multi-year planning horizons, with several favoring these (NRDC, SDG&E, SCE, PG&E, and several others – ORA and TURN - opposed to planning horizons of more than a year or two (ORA and TURN). To ensure ongoing alignment of energy efficiency program activities in the procurement and energy efficiency rulemakings, we refer future issues related to program duration and program cycles to R.01-08-028 for disposition in that rulemaking.

(2) Program Specific Evaluation

The Commission will continue the model established in this rulemaking to require that all proposed program specific procurement related energy efficiency activities undergo Evaluation, Measurement, and Verification (EM&V) activities and modified as necessary in R.01-08-028 as part of the overall Commission portfolio of program activities. Hence, in this rulemaking we will continue the practice of authorizing specific levels of funding for energy efficiency procurement activities, but refer EM&V review of specific program offerings in the future to R.01-08-028.

(3) Energy Efficiency Goals for the Commission's Portfolio of Programs

In our hearings we, took into our record testimony related to utility procurement program proposals related to the 1 percent per capita per year energy reduction goals identified in the July 3, 2003 Assigned Commissioner Ruling (R.01-08-028). Utilities provided information related to their procurement energy efficiency proposals and the per capita reduction goal.

Since that time, CEC has issued a staff workpaper[77] on this issue, and the CPUC has scheduled workshops on the issue. Continued discussion and resolution of what energy efficiency goals, if any, should be established is a continuing subject of review in R.01-08-028. We therefore refer future issues related to the per capita or other types of overarching energy efficiency goals to R.01-08-028.

(4) Future Administration of Energy Efficiency Programs

SDG&E, SCE, and PG&E all urge the Commission in their long-term plan testimony to establish utilities as the lead organization for implementing energy efficiency programs funded through these procurement proceedings. SCE, in particular, argued early-on in the proceeding that it could not guarantee the energy savings projections from its procurement "preferred plan" unless it was specifically charged with administering the plan, and therefore suggested that it might need to implement its "interim plan " with lower energy efficiency savings projections. SCE changed this position in its opening brief, requesting the Commission to adopt the energy efficiency and demand response budgets associated with their "preferred plan." This was done in D.03-12-062. Each of the utilities urge resolution of this issue as soon as possible in R.01-08-028.

Many parties comment on the issue of administration of energy efficiency programs. In its testimony, TURN took no explicit position on whether utilities should or should not administer energy efficiency programs but

[77] *Discussion of Proposed Energy Savings Goals For Energy Efficiency Programs in California,* Energy Efficiency and Demand Analysis Division, California Energy Commission, September 2003

strongly urged the Commission to address this issue in the energy efficiency proceeding. ORA concurs with TURN, urging the Commission to "promptly" address this issue. NRDC urges the Commission as well to resolve the "unsettled issues" regarding the administration of energy efficiency programs. Utility long-term plans also support prompt resolution of this issue in R.01-08-028.

Both the initial Order Instituting Rulemaking and the July 3 ACR for R.01-08-028 identify administration of energy efficiency programs as one of the key issues to be addressed in that Rulemaking, with a goal of resolving this issue in 2004. As the Commission will authorize a uniform portfolio of energy efficiency, we believe it 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 to R.01-08-028.

(5) Utility and Non-Utility Filings for Procurement Related Energy Efficiency Programs

During the course of this proceeding, we have given attention exclusively to utility energy efficiency proposals in response to Commission direction in D.02-10-062 to integrate energy efficiency in utility plans for procurement of baseload energy reductions. We noted in that decision that utilities should consider investment in all cost-effective energy efficiency. In response utilities have filed procurement proposals as described above. We are confident that utilities will make every effort to meet projected energy savings goals. Nonetheless, in this proceeding we wish to broaden the base of parties able to assist the Commission in meeting its stated demand reduction and energy savings goals through the offering of innovative energy efficiency program proposals. We direct that a non-utility role be considered in the delivery of the procurement-related energy efficiency programs as well as public goods charge-related programs at the time the Commission considers the issue of the design of the future administration of energy efficiency programs in R.01-08-028.

b) Other Issues

(1) Valuing Non-Utility Energy Savings in Procurement Forecasts

In the July 3, 2003 ACR (R.01-08-028), the Assigned Commissioner states,

> "I (also) see no distinction in the reliability of the resource between a utility-operated program and one delivered by a non-utility entity. Therefore, I propose to treat all energy efficiency programs as an integrated portfolio to be authorized in this proceeding."

TURN echoes this comment in its opening procurement brief when it suggests that "there is no reason why expected savings from energy efficiency programs conducted by other entities cannot be used as inputs to determine other resource needs, such as energy procurement on the spot market, which may be met by the utilities." We concur with this view. 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.

(2) Valuing Potential Penalty Cost for CO_2 Emissions

In its long-term plan testimony, NRDC requests that the Commission require PG&E, SDG&E, and SCE explicitly analyze financial risks associated with any future regulation of carbon dioxide emissions and incorporate protections for their customers by shifting any risk to customers to the sponsor of the resource creating the risk. NRDC suggests that such risk may occur should utilities build in the future or own coal-fired plants or be involved in other ways with plants presenting a potential financial risk to customers from the $C0_2$ emissions. In reviewing this question, we note that the Commission is 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. For the energy efficiency component of that methodology the Commission has in the past taken into account the environmental benefits associated with energy efficiency by incorporating environmental "adders" to the calculation of the Societal Total Resource Cost Test (TRC). The Commission and its contractor are working with an advisory group to that process that includes representatives from CEC, NRDC, utility and other parties. In this decision, we refer the question of potential financial risks associated with carbon dioxide emissions to R.01-08-028, to be considered in the context of updates the avoided cost 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.

(3) Requirement that Savings Equal to or Greater than those projected in utility forecasts be present in Utility Programmatic Savings Projections

In reviewing utility short-term plan energy efficiency submissions, we have identified the need to ensure that projected utility savings and demand reductions from programs submitted in R.01-08-028, for the programmatic period in question, are in alignment with those forecasted in utility long-term plan in this rulemaking. We therefore establish the requirement here that utility procurement related energy efficiency program submissions be equal to or greater than those forecasted in their long-term plan forecasts for the forecast/program period in question. In making this requirement, we restate the importance of energy efficiency to the overall procurement activity and the need to ensure that projected savings are realized in programs aimed to help the citizens of the state save energy - thereby reducing the need for other non-renewable supply options.

(4) Alignment of Forecast Level Measure Values for Energy Efficiency Savings with Program Level Measure Values for Energy Efficiency Savings

Utility long-term forecasts submitted in this rulemaking utilize measure values for energy efficiency technology applications that are often different from the measure values used to determine savings in utility programmatic submissions. The need exists to ensure that the savings projected in the forecast submitted in this rulemaking are consistent with the projected energy savings calculations for programs submitted in R.01-08-028. We therefore require the utilities to submit within 20 days of this ruling their approach, with relevant examples, of how each utility will ensure that savings forecast in this rulemaking result in savings (and demand reductions) captured in their projected program targets in the Commission's Energy Efficiency Rulemaking.

(5) Direct Access Customer Eligibility for Procurement Energy Efficiency Programs

In its comments AReM raises the issue of direct access (DA) customer eligibility for energy efficiency programs, requesting that the Commission clarify that DA customers should only be responsible for energy efficiency program costs for programs in which they are eligible to participate (p. 23). The record in this proceeding is limited on this issue, yet it is the Commission's understanding based on SDG&E's evidence that all parties paying non-bypassable surcharges for energy efficiency are eligible to participate in these programs. SDG&E witness Smith stated in her July 22, 2003 and in earlier testimony that SDG&E believed that "all classes of customers should be allowed to participate in these programs, including both bundled customers as well as direct access customers."

2. Demand Response

In D.03-12-062, we summarized the policy framework from R.02-06-001 and the Energy Action Plan supporting demand response programs in California, provided an overview of the respondent utilities' demand response proposals from their long-term procurement plans, approved the proposals filed by PG&E and SDG&E, and rejected SCE's request for additional funding of a new Air Conditioning Cycling Program. For purposes of providing a complete discussion of demand response issues in this decision, we repeat below the text from Section VI of D.03-12-062 addressing demand response.

"Demand response, like energy efficiency, is a demand-side resource for the utilities. While energy efficiency resources can often meet baseload procurement needs, demand response can fill on-peak requirements. In D.02-10-062, we directed the utilities to consider all cost-effective investment in demand response that meets their procurement needs. We also stated that the Commission, CEC, and CPA are cooperating in a joint rulemaking, R.02-06-001, to design strategies, tariffs, and programs for additional demand response resources and, in the course of that proceeding, expect to identify quantitative targets for utilities to procure in demand response resources. Further, we directed that the targets adopted in R.02-06-001 should be integrated into the utilities long-term plans.

"Our EAP places a top priority on energy efficiency and demand response programs in its "loading order" of energy resources. Specifically, the plan states:

" • Implement a voluntary dynamic pricing system to reduce peak demand by as much as 1,500 to 2,000 megawatts by 2007.

" • Improve new and remodeled building efficiency by 5 percent.

" • Improve air conditioner efficiency by 10 percent above federally mandated standards.

" • Make every new state building a model of energy efficiency.

" • Create customer incentives for aggressive energy demand reduction.

" • Provide utilities with demand response and energy efficiency investment rewards comparable to the return on investment in new power and transmission projects.

" • Increase local government conservation and energy efficiency programs.

- “ • Incorporate, as appropriate per Public Resources Code section 25402, distributed generation or renewable technologies into energy efficiency standards for new building construction.

- “ • Encourage companies that invest in energy conservation and resource efficiency to register with the state's Climate Change Registry.

“In their filings, the utilities include various interruptible programs, the Commission’s traditional, reliability-based demand response programs, and newer, price-triggered demand response programs such as the Critical Peak Pricing (CPP) tariff currently being implemented for larger customers, and tested for smaller customers in the Statewide Pricing Pilot (SPP).

“In D.03-06-032, the Commission adopted demand response goals for each utility and directed that the IOUs include the MW targets for calendar years 2003 through 2007 in their procurement plans, specifically stating the filings in this proceeding should include: numeric targets coinciding with the findings in this decision; documentation of the amount of demand response (price-triggered) to be achieved by July 1 of each calendar year (with the exception of 2003, where the goals shall be met by the end of the calendar year); which programs and/or tariffs the IOU will rely upon to achieve the targets; and a contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals.

“The MW targets for each utility are set forth in Table 1 of D.03-06-032:

"Table 1. Demand response goals

Year	**PG&E**	**SCE**	**SDG&E**
2003	150 MW	150 MW	30 MW
2004	400 MW	400 MW	80 MW
2005	3% of the annual system peak demand		
2006	4% of the annual system peak demand		
2007	5% of the annual system peak demand		

"Funding for price-responsive demand response programs is also addressed in D.03-06-032. In Ordering paragraph 22, we state:

> 'The total cost expenditures authorized as a result of this decision are capped at $33.0 million over the two calendar years, exclusive of revenue shortfalls and costs related to 'other incentives' which are part of the DWR revenue requirement. Each IOU shall use the cost recovery mechanisms previously adopted in D.03-03-036 as applicable to all Phase 1 programs.'

"PG&E's long-term plan includes its existing demand reduction programs and three new price-responsive programs. No additional funding is requested here. PG&E provides a conservative forecast, testifying on the difficulty of estimating demand reduction levels from new DR programs given various uncertainties. ORA testifies it reviewed the request and supports PG&E's filing on this issue. We adopt PG&E's demand reduction proposal.

"SDG&E's plan reflects an aggressive demand response forecast and encourages the Commission to consider an incentive mechanism for all demand-side programs. SDG&E does not request any funding authorization here.

"In its 'preferred plan,' SCE requests $40 million in pre-approved funding for seven years and approval of a

> 'new and improved' Air-conditioning (A/C) Cycling Program (ACCP). Further, SCE states program review should not be subject to after-the-fact reasonableness review. ORA testifies the expected peak load reduction from this program seems unrealistic and does not support the funding request. CEC recommends this program be referred to R.02-06-001 for in-depth examination.
>
> "We agree with CEC and ORA's recommendation that new ACCP programs need to be reviewed in R.02-06-001 or its successor demand response rulemaking. This allows for program specifics to be carefully examined and for the necessary evaluation and measurement standards to be adopted. The Commission can then directly authorize funding that proceeding. SCE's proposed program is an emergency-demand response program, and the future of these programs, in relation to price-response programs, is a policy issue for R.02-06-001 or its successor. We do not approve SCE's request for funding."[78]

In its direct testimony on the utilities long-term procurement proposals, ORA expresses concern with having the IOUs count new and untested demand reduction programs towards meeting capacity requirements. ORA testifies that "… only the reliable peak load reduction from the existing programs should be considered for planning purposes."[79] We address this resource counting issue in Section IV.A. on Reserves and Resource Adequacy.

The CEC voices a similar concern in this area. In its comments on the proposed decision and alternate from Commissioner Peevey, the CEC states:

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[78] D.03-12-062, pp. 69-72.

[79] ORA Direct Testimony, June 23, 2003, p. 43.

> "All of the soft resource categories – EE, PRD [Price Responsive Demand], DG, and to some extent renewables – require specific monitoring mechanisms. Because these resources are highly dependent on consumer acceptance, it cannot be assumed that what is planned, and committed to, will have the same real world effect."[80]

The CEC adds that "While the CEC supports these preferred resource additions, we believe they must have corresponding monitoring mechanisms if they are to really be relied upon to displace generators."[81]

We agree with the thrust of the CEC's comments on this point and note that with respect to demand response programs, in D.03-06-032, we specifically authorized funding for monitoring and evaluation of such programs. In this decision we do not authorize additional funding beyond that ordered in D.03-06-032 for measuring and evaluation purposes.

Lastly, we note that on November 24, 2003, the Assigned Commissioner in R.02-06-001 issued a Ruling which, among other things, requires the utilities to submit plans on March 31, 2004 describing 2004 efforts for meeting the 5% system peak reduction goal in 2007. As part of the March 31 filing, the utilities will include an assessment of whether the programs authorized in D.03-06-032 need to be modified in order to achieve the 2007 goal, preliminarily identify new programs that may be needed, and propose changes to the demand reduction goals based on initial deployment of authorized programs. We expect any proposed program changes to be part of the utilities'

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[80] Comments of the California Energy Commission on the Proposed Decisions of Commissioner Peevey and Administrative Law Judge Walwyn, December 5, 2003, p. 5.

[81] Ibid., p. 6.

revised long-term plans, however, evaluation of those changes will be considered in R.02-06-001 or its successor rulemaking.

3. Renewables

D.03-12-062 addressed renewables issues in the utilities' 2004 plans, deferring long-term planning issues to this decision and the forthcoming Renewables Portfolio Standard (RPS) rulemaking. The prior decision reaffirmed the guidelines to be used for any interim procurement activity prior to full RPS solicitation, and declined to adopt interim reasonableness benchmarks. That decision also reaffirmed a finding in D.03-06-071 that renewables contracts should have terms no less than 10 years to foster a long-term market for renewables.

In D.03-12-062, we determined that the utilities did not provide a robust analysis of future renewables supply growth in the renewables sections of their respective 2004 and long-term plans. The forthcoming RPS rulemaking will require the utilities to file renewable procurement plans pursuant to Pub. Util. Code § 399.14(a)(3). In those plans, we will require full assessments of renewables needs to meet the utilities' energy and capacity needs and RPS requirements. As we turn our attention now to the long-term plans, we require those plans to contain more detailed estimates of each respective utility's renewable resource profiles, as discussed below.

The long-term procurement plans currently under consideration do not constitute a filing of the required renewable procurement plans, nor does their approval "trigger" an RPS solicitation as detailed in D.03-06-071. That solicitation requires further development of RPS criteria, such as the Market Price Referent (MPR), additional least-cost and best-fit evaluation criteria, and standard contract terms and conditions. We reaffirm that interim solicitations will follow guidelines already established by the Commission.

While PG&E proposes to enter into renewables contracts prior to obtaining an investment-grade credit rating, it states in its 2004 and long-term plans that it is "not required to participate"[82] in the RPS program, is "ineligible to participate,"[83] and goes so far as to say it "will not participate in the RPS program until it is creditworthy."[84,85] D.03-06-071 found that while "utilities that are not creditworthy are not required to procure under the RPS program," such a utility will still have an APT for a given year. SB 67, signed into law after the IOUs filed their plans, provides an optional means of renewables procurement prior to creditworthiness.[86] Thus, PG&E will accrue an APT prior to creditworthiness, and can utilize the adopted flexible compliance mechanisms to meet its APT once it either becomes creditworthy or is able to procure renewables subject to Pub. Util. Code § 399.14(a)(1)(A)(ii). A non-creditworthy utility may also be directed by the Commission to prepare a renewable

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[82] PG&E 2004 plan, p. 4-4.

[83] PG&E long-term plan, p. 6-19.

[84] PG&E 2004 plan, p. 4-5.

[85] See also PG&E 2004 plan, p. 1-17, PG&E long-term plan, 1-21.

[86] Pub. Util. Code § 399.14(a)(1)(A)(ii), as added by SB 67, allows an electrical corporation to undertake renewables procurement to fulfill its RPS obligations once the Commission has determined "[t]he electrical corporation is able to procure eligible renewable energy resources on reasonable terms, those resources can be financed if necessary, and the procurement will not impair the restoration of an electrical corporation's creditworthiness. This provision shall not apply before April 1, 2004, for any electrical corporation that on June 30, 2003, is in federal court under Chapter 11 of the federal bankruptcy law."

procurement plan, as this is not considered "procurement" under Pub. Util. Code § 399.14(g).

PG&E also states at page 1-21 of its long-term plan that its "participation in the RPS is conditioned on it having a demonstrable need for resources and having first attained an investment grade rating…" D.03-06-071 addresses this issue:

> "PG&E's position that 'unmet long-term resource needs' means a specific utility's resource needs, as defined and identified by that utility, is inconsistent with the statewide focus and purpose of the legislation. 'Unmet long-term resource needs' must be considered on a statewide basis, not a utility-by-utility basis, and the Legislature has already essentially found that there are statewide unmet long-term resource needs." (Decision at p. 41.)

Thus, the conditions PG&E attaches to its RPS participation are invalid.

SCE does not explain why its resource model assumes $100 per MWh for "new generic renewables" (Vol. 2, p. 52). This price exceeds any Commission-established benchmark to date. SCE must provide an explanation of the derivation of this value and its use.

We are concerned that SCE modeled renewables as a "generic" block of energy, irrespective of resource type, in its portfolio model. This simplified approach also appears to be inconsistent with Pub. Util. Code § 454.5(b)(2), which requires procurement plans to include "[a] definition of each electricity product, electricity-related product, and procurement related financial product, including support and justification for the product type and amount to be procured under the plan." The IOUs should project some amount or percentage allocation of baseload, peaking and intermittent resources, as each provides a different fit to a utility's resource needs. SDG&E estimates 20 percent wind and

80 percent baseload resources. PG&E estimates its five-year renewables needs will be primarily for peaking and reserve requirements (amounts not specified), with specific baseload needs in 2007 and 2008.

Given their existing base of renewables, contracts signed under the transitional procurement period, and anticipated long-term peaking and baseload needs, the IOUs should be able to estimate renewable resource profiles with a greater degree of specificity. This amount of energy is substantial over the long-term planning horizon, and will undoubtedly affect the utilities' need for other procurement products in the future. The renewable procurement plans will require such an assessment,[87] and it is feasible and prudent to perform this analysis now, on a preliminary basis, in the long-term plans. The utilities should also provide a forecast of the percentage of retail sales met each year by renewables, indicating the projected year for achieving the 20 percent RPS target, and maintaining or increasing that percentage in future years. The long-term plans shall be modified accordingly.

The IOUs should also update their long-term plans to include interim procurement activity from 2003 and any resulting changes to the quantity of renewable energy delivered in subsequent years. The Commission approved PG&E contracts for biomass energy in Res. E-3853. While SCE and SDG&E have renewables solicitations in progress, they should summarize the proposed bids (with publicly filed information) and describe how those products

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[87] Pub. Util. Code § 399.14(a)(3)(A) requires the renewable procurement plan to include: "[a]n assessment of annual or multiyear portfolio supplies and demand to determine the optimal mix of renewable generation resources with deliverability characteristics that may include peaking, dispatchable, baseload, firm, and as-available capacity."

fit into their procurement portfolios. SCE should provide an update on its current RFOs for general renewables and wood waste renewables products. SDG&E should provide an update on its grid reliability solicitation, filed with the Commission on October 7.

The Energy Action Plan calls for the acceleration of the 20 percent RPS goal to year 2010. In its testimony, NRDC urges the IOUs to provide details on how they intend to respond to the Energy Action Plans' accelerated RPS target. The accelerated target will necessitate changes in the IOUs' overall portfolios. Each IOU should modify its plan to include an accelerated RPS target renewables procurement scenario that evaluates any resulting changes to its overall energy procurement portfolio.

Meeting the goals of the RPS on the accelerated schedule of the Energy Action Plan will require a thoroughgoing review of the total resource portfolios of the IOUs, and careful consideration of which nonrenewable resources, in the long run, can or should be displaced or shut down to accommodate renewable development at this scale. This task will be the principal point of interconnection between this docket and the new RPS OIR to be opened early this year. While the near-term need for generation in California must remain central to the resource planning and procurement process, the decisions we make today must not work at cross-purposes with the long-term goals we have embraced for renewable energy development. Without an assertive planning role in this regard it is unclear how the renewable energy goals of the EAP can be met.

We acknowledge that development of renewables to achieve the goals of the RPS will necessitate transmission upgrades and possible construction. The IOUs separately filed conceptual transmission plans to this effect, and the Commission has submitted a report to the Legislature on these issues. These issues will most likely affect long-term planning and will be addressed in I.00-11-001, the RPS phase of this proceeding, and any relevant successor rulemakings.

4. Distributed Generation

In D.02-10-062, we ordered the utilities to explicitly include provision for distributed generation and self-generation resources in their long-term procurement plans. We stated that:

> "Distributed generation and self-generation resources encompass a broad and diverse set of technologies to fit a variety of procurement needs. In addition to providing capacity and energy benefits, they can offer transmission and grid-support benefits that should be included in the utilities' procurement plans." (D.02-10-062, p. 27.)

The Energy Action plan adopted by the Commission, the CPA, and the CEC, provides additional support for distributed generation, placing it second in the loading order and enumerating a number of objectives for the state to achieve:

1. Promote clean, small generation resources located at load centers;
2. Determine whether and how to hold distributed generation customers responsible for costs associated with Department of Water Resources power purchases;
3. Determine system benefits of distributed generation and related costs;
4. Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program;
5. Standardize definitions of eligible distributed generation technologies across agencies to better leverage programs and activities that encourage distributed generation;

6. 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 affecting distributed generation; and
7. Work together to further develop distributed generation policies, target research and development, track the market adoption of distributed generation technologies, identify cumulative energy system impacts and examine issues associated with new technologies and their use.

Based on its review of the utilities' long-term procurement plans, ORA testifies that:

> "It is difficult to compare, or, in some cases, even extrapolate, the self-generation projections by the different utilities.... Another problem arises when utilities lump self-generation with energy efficiency measures, since from the utilities' point of view, both are seen as load reductions. But from ORA's point of view, it is important to be able to separate these out."

In its direct testimony, the Joint Parties Interested in Distributed Generation/Distributed Energy Resources (Joint Parties) find that the utilities did not provide a sufficient level of detail in their respective procurement plans showing how they will incorporate distributed generation into their resource portfolios. The Joint Parties therefore conclude that the utilities did not comply with Commission directives on this issue. Additionally, the Joint Parties recommend that the Commission direct the utilities to undertake a study effort to analyze the cost-effectiveness of distributed energy resources and to assess the size of the potential distributed energy resources market in California. Lastly, the Joint Parties propose a set-aside for distributed energy resources while study work is being conducted.

> "The Joint Parties recommend that the Commission require that the utilities increase procurement from on-site DER projects 20 MW or less by a minimum of 1.5% per year (using 2003 as the baseline year), beginning in 2004, up to a minimum total of 7.5% in 2008. Only new contracts with the [IOUs] for output from the units 20 MW or under would count toward the Joint Parties' proposed DER procurement requirement." (Joint Parties Closing Brief, pp. 11-12.)

The Joint Parties also state:

> ". . . this percentage could be implemented as a placeholder for the first year, while the utilities perform studies of the potential DER market, similar to those that have been performed regarding the energy efficiency market, and develop for Commission approval specific goals and costs for the DER component of long-term procurement plan.
>
> "In any year the applicable requirement is not met, a utility should have to demonstrate why this is the case, and how it place to make up for the any DER procurement shortfall in the following years. In addition, the requirement could be subject to revision up or down on an annual basis, depending on resource adequacy and market conditions. The need for a formal DER procurement directive beyond 2008 would be evaluated during a procurement proceeding or a procurement update proceeding scheduled for completion prior to 2008." (Joint Parties' Direct Testimony, pp. 16-17.)

In lieu of setting a mandated set-aside, the Joint Parties propose an alternative approach whereby the Commission would establish a "procurement goal" for distributed energy resources. The goal would be quantified as set forth above and the utilities would be required to explain if they failed to meet the objective. If the Commission determines that the utilities are not making "reasonable efforts" to meet the goal, the Commission would then elevate the goal to a directive.

We find that beyond including forecasted levels of customer-side distributed generation, the utilities' procurement plans do not contain explicit proposals or strategies for promoting distributed generation within their respective service territories as a supply-side procurement resource. In the long-term procurement plans, the utilities' treat distributed generation as a demand-side program, netting out the effects of distributed generation as part of the load forecasting process. While not foreclosing the potential of using distribution generation as a supply-side option in the future, the utilities indicate that such efforts should await the results of cost/benefit studies.

We agree with ORA's findings that it is difficult to compare and extrapolate the distributed generation forecasts from the utilities long-term procurement plans. 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. We recognize that distributed generation encompasses many types of applications and technologies and different parties embrace different definitions of this resource category. It's important that each utility clearly define the resources it includes in its forecast of distributed generation.

As described in D.03-02-068, the Commission plans to institute a new rulemaking on distributed generation that will, among other things, address the various cost/benefit and market issues mandated by AB 970, SBX1-28, and the Energy Action Plan. We will refer the Joint Parties' proposal to the future rulemaking. At this time, we will not predetermine the outcome of these issues in advance of the rulemaking, and therefore do not adopt the Joint Parties recommended approach for a set-aside.

5. Transmission

In D.02-10-062, we stated our intent to take a comprehensive outlook when considering resource procurement to meet demand. This approach should balance the benefits of generation, transmission, and demand-side options in meeting need in a cost-effective, environmentally sensitive manner. We also made clear in the EAP our objective of ensuring there is adequate transmission to support California's needs, stating:

> "Reliable and reasonably priced electricity and natural gas, as well as increasing electricity from renewable resources, are dependent on a well-maintained and sufficient transmission and distribution system. The state will reinvigorate its planning, permitting, and funding processes to assure that necessary improvements and expansions to the distribution system and the bulk electricity grid are made on a timely basis."

Each utility in its long-term plan included the transmission upgrades for reliability that had been reviewed and approved through the ISO's annual grid study. They also included a general assessment of additional transmission needed to support power imports for future needs, based on production cost computer modeling. In its plan, SCE cites the need for additional transmission capability to the Southwest for economic reasons, to access surplus capacity and energy, and references its intention to file for a Certificate of Public Convenience and Necessity (CPCN) for Devers Palo Verde 2 line.

ORA and the ISO testify that the utilities' plans are not sufficiently detailed to fully assess the deliverability of power that each utility, particularly PG&E, relies on to meet future needs. In particular, PG&E relies on "generic" resources within the western grid. In hearings, the ISO testified that it could work with the utilities to identify conceptual scenarios for these generic units, i.e. general geographic regions, add scenarios for distribution within the state, and then combine the three utilities to test whether or not these scenarios are compatible with the transmission system and transmission system plans.[88] In its brief, the ISO states this would be the minimum deliverability requirement needed. SCE supports a deliverability showing for resources imported into the ISO control area, but does not support local deliverability requirements.

We find here that a minimum requirement is that the IOUs work with the ISO on defining conceptual scenarios for resources imported into the ISO control area and deliverable to the individual IOU's load, so that after the June 2004 plans are filed, the ISO can timely run combined scenarios, serve testimony, and fully participate in our hearing process. While we maintain that deliverability is a critical criteria for a resource to "count" towards a LSE's resource adequacy requirement, as we discussed earlier, we look to further

[88] Transcript 3864-5, Volume 31.

defining and refining a standard of deliverability following our resource adequacy workshop.[89]

In its testimony, the CEC states that the Commission's focus in D.02-10-062 was generation-focused and we must expand to include generation, transmission, and demand-side or customer-oriented alternatives. Further, the CEC states its IEPR process will establish the integrated planning process that we should use in this proceeding to determine the combination of demand side or customer-oriented and infrastructure investments (including generation and transmission) that best meet California's short- and long-term needs.[90] While we welcome the CEC participation and expertise in our proceeding, we do not support requiring the utilities to adopt the forecasts and resource plans of the IEPR. We strongly believe that the utilities themselves must be responsible and accountable for providing their customers reliable service and just and reasonable rates; this is the utilities' statutory obligation to serve.

In guiding the utilities' long term planning process, we focus on developing an integrated resource approach, one that recognizes our policy priority for demand-side resource additions, and that optimizes generation and transmission resources.

SDG&E presents this approach in its plan. It places emphasis on the first 5 to 10 years of the plan, since these are the years for which policy and implementation decisions need to be made in the near term, and allows for a

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[89] In assessing deliverability for specific PPAs the utilities propose entering, we should also look to see that the supplier pays for any network upgrades needed to ensure power deliverability under the contract.

[90] Exhibit 49, pages 5-6.

level of short-term and medium term resources that provide sufficient flexibility. SDG&E:

> First, determined the level of cost-effective energy efficiency available to SDG&E;
>
> Second, demand response programs were added to meet a challenge of reducing peak demand 5% by 2007;
>
> Third, renewable resources were added to ensure 20% of the energy SDG&E provides to its customers will come from renewable sources by 2017 or sooner; and
>
> Fourth, developed and tested four distinctly different candidate resource portfolios that could fill any remaining supply gap.

We commend SDG&E for incorporating both a deliverability component as well as a local reliability aspect in their approach. We agree that these are critical components to a comprehensive approach to meeting need. Including a local reliability criteria for new generation in order to address transmission issues in load pockets is critical to addressing specific local reliability issues, which exist predominantly in SDG&E's and PG&E's service territory.

Currently, local reliability is addressed through Reliability Must-Run (RMR) contracts. Reliability Must-Run units are generation units that the CAISO has determined have to run for *local* reliability reasons. They are predominantly in transmission-constrained areas where local generation near load balances the limitation on imports over constrained transmission lines. While RMR serves an important purpose, RMR contracts are annual contracts that detract from a comprehensive infrastructure planning approach. They are also expensive, costing $360 million in 2003. There are several reasons that RMR contracts are expensive: 1) the generator is in an advantageous bargaining position since by their very nature RMR contracts are required for reliability; and 2) many of the generating units are very old and inefficient.

The IOUs in their long-term procurement plans are in a position to foster a more comprehensive approach to meeting local and system needs through long range plans that incorporate generation, transmission, and demand-side trade-off analysis from a least cost perspective. We direct the utilities to include a local reliability component in their next procurement plan. This approach will facilitate a more comprehensive approach to resource planning. It is our intent that this approach will increase the effectiveness of resource procurement and result in lower costs to ratepayers.

While we conceptually agree with SDG&E's model, more refinement is necessary in specifying the cost/benefit analysis that should be performed in each step and the level of specific project analysis to include. ORA finds that SDG&E's plan failed to incorporate all anticipated new generation, and its demand response programs were untested, thereby undermining the reliability of the planning assumptions. We agree with both of these points.

Save Southwest Riverside County (SSRC) testifies that the transmission component of SDG&E's preferred proposal is not supported by substantial evidence. Specifically, it cites SDG&E's inclusion of a "Near-term Interconnection Project" that would be constructed and available to serve load by the summer of 2008. SSRC cites to SDG&E's testimony on cross-examination that this is not the Valley-Rainbow line, and states that since licensing and construction of another major new transmission line would take five to six years, SDG&E's plan is risky, and perhaps infeasible. This is a valid criticism that SDG&E should address in its next plan.

The City of Chula Vista states that SDG&E's proposal shows that existing transmission systems will be fully utilized by 2005, and that additional transmission capacity must be added by 2008. The City is concerned that future transmission lines be given early and active coordination with affected local jurisdictions, to include specific notice and a public involvement process. The City would like the Commission to consider: requiring the removal of old, surplus, above-ground lines when new ones are added, tying in local power sources and renewables in evaluating sites, upgrading line capacity for growth, and the consideration of growth in siting new or replacement lines. We give the City assurance that before a new transmission line could be authorized, a separate CPCN process would be required. Our CPCN process provides full public notice to all communities affected, a detailed environmental assessment under CEQA standards, and a specific finding of economic need.

SCE requests that the Commission (1) avoid duplicating the transmission project need assessments performed by the ISO with the assessment performed by the Commission in its General Order 131-D CPCN; and (2) refrain from conducting transmission project need assessments in this proceeding unless the results of those assessments can and will be adopted in the project's separate General Order 131-D CPCN proceeding. The Commission intends to open shortly a new transmission rulemaking to address this issue. Our commitment under the EAP is:

> "The Public Utilities Commission will issue an Order Instituting Rulemaking to propose changes to its Certificate of Public Convenience and Necessity process, required under Pub. Util. Code § 1001 et seq., in recognition of industry, marketplace, and legislative changes, like the creation of the CAISO and the directives of SB 1389. The Rulemaking will, among other things,

> propose to use the results of the Energy Commission's collaborative transmission assessment process to guide and fund IOU-sponsored transmission expansion or upgrade projects without having the PUC revisit questions of need for individual projects in certifying transmission improvements."

6. Fuel Diversity in Non-Renewables

The California Energy Commission (CEC) notes that there are concerns about California's increasing dependence on natural gas. The latest version of the *2003 Integrated Energy Policy Report* (IEPR), states:

> "With demand for natural gas increasing to meet the needs of a growing electricity generation market, concerns have emerged among state policy makers about California's increasing dependence on natural gas. These concerns have become even more pronounced with increased price volatility."[91]

CEC's recommendation is to mitigate the risk of relying heavily on natural gas by reducing demand for natural gas for power generation through greater reliance on renewable generation. The draft final report is less encouraging about substituting other non-renewable fuels for gas:

> "Using other fuels can also reduce the demand for natural gas facilities. For a host of legal, environmental, and cost reasons, nuclear, large hydroelectric, residual fuel oil, and coal facilities are unlikely candidates for offsetting natural gas-fired generation for California. On the other hand, the development of cost-effective renewable resources (wind, geothermal, biomass, and

[91] Page 22.

> solar) have [sic] tremendous potential in California to meet part of our future demand."[92]

It is clear that the CEC does not see the use of alternative fuels, except for renewable sources, as a long-term source of diversity in generation sources in California.

SDG&E proposed a Balanced Portfolio as part of its long-term plan. The plan posits increased transmission capability, additional on-system generation both prior to and after the transmission addition, and off-system resources including the fuel diversity represented by a coal-fueled resource. SDG&E's Robert Resley's testimony notes that its ability to add fuel diverse resources is constrained by the nature of its service territory, public policy, and possible limited availability of non-fossil resources.[93] SDG&E recognizes that the advantage of diversity, a significant reduction in potential price volatility by reduced dependence on gas prices, would be counterbalanced by additional emissions.

The long-term plans of the other utilities, PG&E and SCE, do not mention fuel diversity by name, and do not include non-gas power plants in their future plans.

California is an environmentally sensitive state both by its geography and by its politics and sensitivities. Conventional power plants are difficult to site here. Even those fired by the cleanest technologies and fuels – at this time, that means natural gas – are not generally welcomed here. The most recent data show that electric generation in California from coal, petroleum, and

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[92] Page 23.

[93] Page 9.

other gases besides natural gas accounts for only three-percent of total generation in the state, compared to about 56 percent for natural gas.[94] SCE is in the midst of a proceeding before us, A.02-05-046, on the future disposition of the Mohave power plant, which is the largest single coal-fired source for any of the utilities, which may provide significant fuel diversity benefits. In order to ensure that a variety of fuel diversity options exist in SCE's revised long-term plan, we expect SCE's revised long-term plan to contain scenarios both including and excluding the Mohave power plant.

SDG&E is correct in arguing that a balanced portfolio that includes a coal-fired resource would require new transmission, for it is very unlikely that a coal-fired plant ever could be built within its service area.

Fuel diversity is not only a matter of choices of different fuels. The principal advantage we are looking for, reduced likelihood of shortages and price spikes, can be achieved through greater reliance on additional sources of fuel, including natural gas itself. It is possible that the addition of at least one Liquefied Natural Gas (LNG) port capable of serving gas to Californians, including California's electric power plants, can provide at least some of the benefit we are searching for in fuel diversity. Only in this case, it would not be diversity of the fuel types, but of the fuel sources.

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[94] DOE/EIA State Electricity Profiles 2001, published October 2003, Energy Information Administration, US Department of Energy.

7. QFs

In D.03-12-062, we directed the IOUs to extend expiring or expired contracts with existing QFs for another year until December 31, 2004. We did this in order to assure the continuing availability of QF power during 2004 through the use of SO1 contracts under the following conditions:

- The QF must have been in operation and under contract to provide power with an IOU at any point between January 1, 1998 and the effective date of this decision; and
- The QF contract must be set to expire before January 1, 2005, or have already expired.

However, D.03-12-062 did not allow for any new QF contracts with new QFs during the short interim period between the issuance of that decision and the issuance of this decision.

Currently, there are about 600 QFs under contract to PG&E, SCE, and SDG&E. These QFs supply power used to serve about one-fourth of the combined retail load for the three utilities. QFs have been reliably providing power for over 20 years, under standard offer and fixed-priced contracts, and under some non-standard offer contracts, approved by this Commission. As we discussed in D.02-08-071, QF power provides many benefits to California:

> "As a general proposition, we find that QF power provides significant benefits to the state, in the form of more efficient industrial processes, as well as electric power. QFs have continued to provide power to the state during difficult circumstances during the past several years. A consequence of not making provisions for continuing QF contracts would be more QF power going off-line, creating additional net short that the utilities would need to procure during the interim period." (D.02-08-071, p. 31.)

The QF industry marked its beginning with the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978 which required utilities to purchase QF power under certain terms and conditions. By 1995, FERC noted that the QF industry had matured considerably:

> "The QF industry is now a developed industry and the need for integration of policy objectives under PURPA and other federal electric regulatory policies is pronounced. This is particularly the case given the fact that the electric utility industry is in the midst of a transition to a competitive wholesale power market, and some States, including California, are considering direct access for retail customers."[95]

Although this determination was made eight years ago, the challenge of correctly implementing PURPA for a developed QF industry, which now co-exists with increasingly developed wholesale power markets, does present a considerable challenge. We must strike the proper balance between certain policy preferences and a myriad of legal requirements.

This industry is so mature, in fact, that QF power contracts are actually set to expire at a significant rate over the next five to seven years. By 2008, expired QF contract capacity is expected to exceed 1,000 MW and approach 1,800 MW by 2010. SCE is projected to lose the most QF capacity during this time period.

[95] *Southern California Edison and San Diego Gas & Electric, 70 FERC 61,215 (1995)*

Expiring QF Contract Capacity

	2005	2006	2007	2008	2009	2010
PG&E QFs	0%	1%	6%	8%	19%	23%
SCE QFs	1%	11%	11%	31%	38%	43%
SDG&E QFs	0%	0%	0%	0%	0%	0%
Combined QFs	1%	6%	8%	19%	28%	32%

a) Parties' Comments on the Proposed Decisions

On December 8, 2003, PG&E, SCE, CCC, CAC/EPUC, and IEP filed their respective comments on QF issues[96] contained in the ALJ Walwyn Proposed Decision (PD) and the Peevey Alternate Decision (AD). On December 15, 2003, these same parties filed reply comments,[97] as well as comments on the Lynch Alternate Decision. Ridgewood filed comments on all three proposed decisions on December 15, 2003.

In comments on the ALJ PD and the Peevey AD, PG&E was strongly supportive of the "recognition that ratepayers have paid above-market prices for QF power." PG&E suggested that the term of new SO1 contracts be limited to one year, during which time the Commission could revise QF pricing. PG&E requested that QF payments under new SO1 agreements be subject to later true-up to the extent they exceed the utilities' avoided costs. PG&E further requested that any additional interim SO1 contracts be energy-only contracts for months where capacity is not needed (PG&E, pp. 17-19).

SCE comments that it would be inconsistent for the Commission to conclude that (1) short-run avoided cost (SRAC) pricing exceeded utility avoided cost and then (2) direct IOUs to extend QF contracts through 2004 at current over-market SRAC prices. SCE states that some accommodation must be made to reconcile the policy conclusion that SO1 contracts should be extended with the evidence that SRAC prices were too high.

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[96] SDG&E commented only on the QF price risk hedging issue, which we will not address in this section of the decision.

[97] CAC/EPUC did not file reply comments.

IEP comments that the PD and AD misread the *Ketchikan* waiver as extending to both energy and capacity, which IEP contends is applicable only to capacity. IEP further states that the PD and AD unlawfully step into FERC's role of granting waivers from PURPA's purchase obligation, which would be a violation of federal law. IEP states that PURPA continues to require utilities to purchase power from QFs.

CCC comments that the Commission cannot lawfully excuse IOUs from their PURPA purchase obligation. It cannot condition PURPA purchase obligation on a determination of need for the power. CCC contends that the Commission should order IOUs to take QF power and to do so using the same interim 2003 SO1 contract that was authorized in Commission decision D.02-08-071. According to CCC, the PD must clearly reject the notion that PURPA is satisfied simply by allowing QFs to participate in competitive solicitations, and the PD’s and AD’s findings on SRAC Pricing (i.e., that SRAC prices are above market and inequitable) are unsupported by the record.

CAC/EPUC comments that the Commission must uphold the QF purchase obligation in order to secure the many benefits of QF power, which include increased capacity in California, reduced impacts on the grid, increased system reliability, reduced consumption of natural gas, greater efficiency, and environmental benefits.

In its December 15, 2003 Reply Comments on the PD and Alternates, PG&E contends that QF parties incorrectly argue that the Commission must seek a waiver of the PURPA purchase obligation requirement from FERC in order to limit the utilities’ future QF purchase obligation to those times when power is needed. PG&E states that Commission suspension of Standard Offer contracts is not predicated on FERC approval, even though suspension is due to oversupply. PG&E contends that the IOUs are in compliance with PU Code Sec. 372(a), regarding encouragement of cogeneration, because current QF power represents a significant portion of IOU power and thus there is no current need for a long-term standard offer to encourage additional cogeneration. PG&E states that it looks forward to the use of "new, more accurate mechanisms to establish the utilities' avoided costs [other] than the current outdated [SRAC] methodologies or administratively determined benchmarks." In addition, PG&E contends that its "1,000-hour curtailment" proposal would not cause QFs to shut down.

In its reply comments, SCE reiterates its position that the PURPA purchase obligation is not an unconditional, mandatory purchase obligation, but is rather a requirement that should be balanced against a utility's need for power and with the standard for just and reasonable rates. SCE also more broadly contends that the utilities cannot lawfully be required to pay current SRAC for QF power, given that the utilities have paid above-market prices for QF power in certain time periods.

In its reply comments, CCC states: (1) SCE misrepresents the record to conclude that SRAC exceeds avoided costs; (2) next year's SRAC review should not be prejudged by the limited and conflicting evidence on this record; (3) unsubstantiated SRAC findings should be deleted; and (4) PURPA purchase obligations should not be contingent on a utility's own determination of need for QF power.

In its reply comments, IEP opposes PG&E's request to subject new SO1 QF contracts to a later true-up to the extent posted SRAC prices exceed utility avoided cost. IEP contends that (1) the proposed true-up is inconsistent with established precedent whereby QF prices have always been set prior to delivery, and (2) a true-up would "cloud investment and place [QF operations] at risk." IEP also opposes PG&E's request to remove capacity payments from new SO1 contracts during months when the utility does not forecast a need for such capacity. IEP contends that this PG&E proposal is unfounded, as the utility has not presented any publicly available data in support.

In its December 15, 2003 comments on all three proposed decisions, Ridgewood Olinda contends that each PD must be modified to (1) require expressly that utilities purchase all electricity offered for sale by QFs at avoided costs, (2) to eliminate the waiver of this obligation based on utility need, and (3) to eliminate the disparate treatment of new and existing QFs.

b) Parties' Recommendations Not Yet Discussed

CCC Positions

CCC recommends that QFs should be allowed to (1) preferably enter into 10-year SO1 contracts, or alternatively, short-term annual SO1 contracts; (2) bid to provide long-term procurement products to the IOUs (such as firm capacity products), while (3) retaining their right to sell energy at SRAC prices to the IOUs in other hours. CCC contends that its long-term procurement proposal (for cogenerators) would provide benefits to both ratepayers and QFs, including conservation, energy efficiency, additional supply, and market-based pricing under SRAC.

CCC also proposes a way to mitigate impacts of excess base load power through the expanded use of bid curtailment programs. IOUs could utilize such programs to economically back-down QF power. CCC states that these programs encourage QFs with operational flexibility to reduce their output during hours when the utility has too much must-take power. The purchasing utility would provide each of its QFs with the opportunity to bid a price for megawatt-hours of production that each QF can curtail. The IOU can accept those bids that offer ratepayer benefits.

CCC also notes that SRAC TOU (time of use) factors could be revised to more accurately encourage QFs to deliver power when it is needed. CCC states that the vast majority of QF power is either under non-standard contract or is on 5-year, fixed price contracts at 5.37/kWh until mid-2006. Thus, modifications to SRAC pricing would have no appreciable effect until after mid-2006. (CCC Direct Testimony, 06-23-2003, p.5, line 20).

CCC observes that PURPA is still law, that it has not been repealed, and that the statute still requires "IOUs to purchase power from QFs at prices based on the IOUs' full avoided costs" (CCC Direct Testimony, 06-23-2003, p.10, line 26). CCC notes that D.02-08-071 required the IOUs to offer SO1 contracts during the interim procurement period (p.12, line 4). CCC contends that a long-term SO1 contract "will allow the IOU to meet its PURPA purchase mandate…" (p. 4, line 40.)

CCC states that QF capacity will decline sharply after 2005, as a result of the termination of the large cohort of QF contracts with 20-year terms for projects that began operations from 1985 to 1990." (CCC Direct Testimony, p. 7, lines 18-21). CCC contends that more capacity needed by 2008, even though CEC 'incorrectly' assumes constant QF power:

> "The CEC forecast appears to assume that present levels of QF generation are maintained. Even assuming QF resources are retained, the CEC forecast suggests that, on a statewide basis, another 2,000 to 5,000 MWs of peak capacity will be needed by 2008, simply in order to maintain reserve margins in the range of 15% to 20%." (CCC Direct Testimony, p. 8, line 8.)

CCC contends that QFs can supply additional power in 2004 and beyond:

> "Cogeneration projects that could supply additional power to the IOUs in 2004 are, for the most part, already built and have operated successfully for many years. Most are located in the state's load centers, improve the reliability of the state's electric grid, and avoid the need for the California Independent System Operator (ISO) to contract for reliability must-run (RMR) generation." (CCC Direct Testimony, p. 3, line 3.)

CCC notes that the IOUs can readily hedge their exposure to high SRAC prices through the use of financial hedge products. SCE hedged its QF price risk in 2002 and 2003. PG&E and SDG&E also have such hedging authority. (CCC Direct Testimony, p.10, line 34). CCC states that QFs avoided the construction of additional central station coal and nuclear power plants, such as the Diablo Canyon and SONGS plants that were built in the 1980s. CCC also notes that there are conservation and efficiency benefits associated with cogeneration -- the dual production of two useful forms of energy from a single fuel source. (Direct Testimony, p. 2, line 22.).

CAC/EPUC Positions

On QF issues, CAC/EPUC contended that (1) the IOU power solicitation proposals do not solely satisfy utility PURPA purchase obligation requirements, and (2) changed circumstances do not preclude QF cost recovery, thus existing QF contracts must be upheld. CAC/EPUC cites *Cogen Lyondell, Inc., et al., 95 FERC 61,243 (2001)* in support of its first contention on PURPA purchase obligation requirements: "The opportunity to participate in a solicitation process is a far lesser right than that expressed in the FERC rules and may not be sufficient to encourage QF cogeneration as prescribed by Federal law" (CAC/EPUC Direct Testimony, 06-23-2003, p.5, line 6). With regard to existing QF contracts, CAC/EPUC notes that *New York State Electric & Gas Corp., 71 FERC 61,027 (1995)* upholds existing QF contracts even under changed circumstances. Both of these FERC orders are discussed in more detail below.

During cross-examination of PG&E's QF witness (Pappas), CAC/EPUC counsel noted that existing State of California policy, as set forth in Pub. Util. Code § 372(f), also encourages the continued development, installation, and interconnection of clean and efficient self-generation and cogeneration resources (Tr. 5694, lines.20-28), in addition to the federal PURPA statute. Pub. Util. Code § 372(f) is as follows:

> "372 (f) To encourage the continued development, installation, and interconnection of clean and efficient self-generation and cogeneration resources, to improve system reliability for consumers by retaining existing generation and encouraging new generation to connect to the electric grid, and to increase self-sufficiency of consumers of electricity through the deployment of self-generation and cogeneration, both of the following shall occur:
>
> > "(1) The commission and the Electricity Oversight Board shall determine if any policy or action undertaken by the Independent System Operator, directly or indirectly, unreasonably discourages the connection of existing self-generation or cogeneration or new self-generation or cogeneration to the grid.
>
> "(2) If the commission and the Electricity Oversight Board find that any policy or action of the Independent System Operator unreasonably discourages, the connection of existing self-generation or cogeneration or new self-generation or cogeneration to the grid, the commission and the Electricity Oversight Board shall

> undertake all necessary efforts to revise, mitigate, or eliminate that policy or action of the Independent System Operator."

ORA Positions

Although ORA does not appear to oppose PG&E's power solicitation and SO1 contract proposals, ORA does state that these seem to be "inconsistent with the Commission's intent for a limited revival of SO1 contracts" (ORA Direct, p.80). Regarding PG&E's 1,000-hour discretionary curtailment proposal, ORA's direct testimony at page 79 did not reflect a full understanding of PG&E's proposal, as evidenced during hearings (Tr.5883, through 5886). Under cross- examination by CCC, ORA did express concern over the possibility that "PG&E's exercise of the [1,000 hour] curtailment right [might have] the effect of shutting down [some] QF operations" (Tr.5886, ln.17-20). ORA is not opposed to PG&E's proposal to revamp SRAC pricing methodologies, but ORA notes that no specific details were provided.

ORA's position on SCE's position that, "its PURPA obligations will be fully satisfied by affording QFs the opportunity to participate in upcoming solicitations for renewable and/or non-renewable contracts," is ambiguous:

> "If, as SCE represents, additional SO1 contracts will not be a good fit to SCE's primary need, then so be it. SCE should not force itself to enter into this type of contract beyond those already required in existing Commission orders. SCE has indicated several planned new contracts during the plan period through 2012. But SCE should describe in more explicit terms the solicitation opportunities it plans to make available to QFs and all other bidders in both renewables and non-renewables." (ORA, Direct Testimony, p. 82.)

As a policy matter, ORA states that SCE should be more explicit in identifying specific opportunities for QFs to bid in future SCE solicitations.

c) Discussion

The spectrum of QF positions in this proceeding is defined on the one end by an absolute, mandatory PURPA purchase obligation regardless of utility need, and on the other end by a solicitation-only opportunity for QFs to bid on yet-to-be-defined power products at future yet-to-be-specified dates. We are not only faced with a range of policy choices but also with complex legal requirements set forth in federal and state law. We are cognizant of the fact that, whatever our policy preferences, we must make our policies conform to the legal requirements. Thus, what follows is a discussion of our legal constraints.

(1) The PURPA Purchase Obligation Requirement

In our Interim Opinion in this rulemaking, D.02-08-071, we discussed the applicable federal and state mandates associated with PURPA, along with our interim approach on QF issues. In that decision, we stated that, "[a]lthough the requirements of PURPA give us considerable discretion and do not obligate us to continue SO1 contracts [until long-term procurement plans have been adopted], we nonetheless must comply with PURPA." In the three proposed decisions that were circulated for comment, we stated that with regard to QFs, "the issue of the obligation to purchase QF power according to the requirements set forth under PURPA is at issue in this rulemaking." This characterization of the QF issue and associated discussion was taken by some parties as an attempt to overreach our jurisdiction in order to make a determination that is clearly under the purview of FERC. This was not, and is not, our intention. We expressly acknowledge the authority of FERC to grant waivers or limited waivers of the PURPA purchase obligation as set forth in 18 CFR 304(f). However, in the interest of clarity, we shall provide more specific guidance with regard to the point at issue here in this rulemaking regarding QFs, namely, the implementation of the PURPA purchase obligation by California's IOUs.

In 105 FERC 61,004 (Para. 20), FERC clearly summarized the PURPA purchase obligation requirement, along with some associated provisions:

> "[FERC] implemented the purchase obligation set forth in PURPA in Section **292.303** of its regulations, **18 C.F.R.** § **292.303**(a) (2003), which provides: Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility . . . . Section 292.304, in turn, requires that rates for purchases shall: (1) be just and reasonable to the electric customer of the electric utility and in the public interest; and (2) not discriminate against qualifying cogeneration and small power production facilities. **18 C.F.R.** § 292.304(a)(1) (2003). The regulation further provides that nothing in the regulation requires any electric utility to pay more than the avoided costs for purchases. **18 C.F.R.** § 292.304(a)(2) (2003)." (Emphasis added.)
>
> "'Avoided costs' is defined as 'the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.'" **18 C.F.R.** § 292.101(b)(6) (2003)

Several other recent FERC rulings shed light on states' obligations under PURPA.

In particular, the PURPA purchase obligation is subject to specific curtailment provisions in 18 C.F.R. Section 292.304(f)[98]. Additionally, the waiver provision in 18 C.F.R. 292.402 provides further flexibility to states in their implementation of the PURPA purchase obligation, should a state decide to pursue such a course of action at FERC. Specifically, section 292.402 provides for a waiver of Subpart C of Part 292. Subpart C is titled as, and sets forth, "Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978." The waiver allowed for under section 292.402 applies to sections 292.301 through 292.308, excluding section 292.302, but including section 292.303, which is the particular section that sets forth the

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[98] 292.304 (f) Periods during which purchases not required.

(1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

obligation of electric utilities to purchase QF power. Section 292.402 reads as follows:

> "(a) State regulatory authority and non-regulated electric utility waivers. Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or non-regulated electric utility may, after public notice in the area served by the electric utility, apply for waiver from the application of any of the requirements of subpart C (other than 292.302 thereof).
>
> "(b) Commission action. The Commission will grant such a waiver only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA."

It is clear from this language in FERC's regulations that states, through their utility regulatory commissions or individual utilities, have the authority to request FERC authorization to waive the applicability of the PURPA purchase obligation under certain conditions.[99] During the course of these proceedings, a number of QF parties have raised the issue of the scope of this waiver authorization, citing a FERC decision, *Cogen Lyondell, Inc., et al., 95 FERC 61,243 (2001),* as a definitive refutation of PG&E's and SCE's power solicitation proposals, which the utilities claim will satisfy their PURPA purchase obligation requirements.

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[99] We note that the right to seek any such waiver rests with the state regulatory commission, and not with the utilities over which any such commission may have regulatory authority.

The relevant language from this case is as follows:

> "The Commission recognized, when it promulgated its regulations implementing PURPA, that the purchase obligation could be waived in some situations. See Small Power Production and Cogeneration Facilities: Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs. Regulations Preambles 1977-1981 30,128 at 30,871, 30,894 (1980), order on reh'g, Order No. 69-A, FERC Stats. & Regs. Regulations Preambles 1977-1981 30,160 (1980), aff'd in part and vacated in part, American Electric Power Services Corporation v. FERC, 675 F.2d 1226 (D.C. Cir 1982), rev'd in part, American Paper Institute, Inc. v. American Electric Power Service Corporation, 461 U.S. 402 (1983)."
>
> "The Commission has in the past granted waiver in certain limited circumstances. See City of Ketchikan, Alaska, 94 FERC 61,293 (2001) (Ketchikan); Seminole Electric Cooperative, Inc., 39 FERC 61,354 (1987); Oglethorpe Power Corporation, 32 FERC 61,103 (1985), reh'g denied, 35 FERC 61,069 (1986), aff'd Greensboro Lumber Company, 825 F.2d 518 (D.C. Cir. 1987). In the recent Ketchikan order, for example, the Commission granted waiver of the purchase obligation based on a showing that QF capacity was not needed and would merely displace sales of capacity from other resources. <u>Here, the Texas Commission has offered no such specific showing, relying instead on broad competitive assertions</u>." *Cogen Lyondell*, Inc., et al., 95 FERC 61,243 (2001), footnote 3 (emphasis added).

With regard to the breadth of the Texas Commission's request, FERC stated:

> "We will deny the Texas Commission's request for waiver. As an initial matter, what the Texas

> Commission requests <u>is essentially a complete waiver</u> of the PURPA purchase obligation <u>for all Texas utilities</u>. <u>On this record</u>, we cannot grant such a waiver." *Cogen Lyondell*, Inc., et al., 95 FERC 61,243 (2001), page 4 (<u>emphasis added</u>).

Thus, FERC's *Cogen Lyondell* order addresses broad requests for waivers but not specific circumstances where waivers may be granted.

Another recent FERC case that addresses circumstances potentially relevant in California today is *City of Ketchikan, 94 FERC 61,293 (March 15, 2001)*. In that order, FERC granted a limited waiver of the PURPA purchase obligation because a proposed QF contract would, in fact, displace existing utility resources and result in additional unneeded power. PG&E describes the order in its September 22, 2003 reply brief:

> "In *Ketchikan*, a self-certified QF who had not yet constructed a new facility attempted to displace energy the City utility was already under contract to purchase by requiring it to purchase from its proposed QF. The City sought and was granted a waiver of any PURPA requirement to take power from the new QF. FERC approved the waiver because "<u>there is no obligation under PURPA for a utility to pay for capacity that would displace existing capacity arrangements</u>." (*Id.* at p. 62,061.) Because capacity from the new project was not needed, FERC held that its acquisition did not avoid "building or buying future capacity." (*Id.* at p. 62,062.) FERC also held "compliance with the utility purchase obligation, by means of a purchase that would displace power from the Four Dams Pool Initial Project, is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA." (*Id.* at p. 62,061.) In support of its ruling, FERC also cited a long-standing Order No. 69,

> FERC Stats. & Rags. Preambles 1977-1981 ¶ 30,128 at p. 30,870, which provides that <u>a qualifying facility should only be required to be paid for "energy or capacity the utility can use to meet its system load</u>." (<u>Emphasis added.</u>)

This case would seem to address issues relevant to California's current situation, where utilities have little need, in the short-term, for baseload power such as that provided by QFs. This is primarily due to the excess baseload power represented by the DWR contracts between now and 2005 or 2006 (depending on the utility). After that time, the net long positions of the utilities due to DWR contracts drop off dramatically.

Thus, we have a short-term situation when a large number of existing QF contracts are expiring just at the time when the utilities have excess power. This situation is temporary, however, and should not dictate our long-term policy. As CCC points out, QFs provide numerous benefits to California, including environmental characteristics, efficiency, contributions to the local economy, as well as power resources. It is in the State's interest for QFs to continue to provide those benefits over the long term, especially where they are already in existence. This is separate from the issue of the price to be paid for QF power going forward, which we have already determined in D.03-12-062 needs to be revised.

The situation related to existing QFs is distinguishable from the question or whether the Commission must provide an opportunity for new QF contracts. FERC's *Ketchikan* order and Order No. 69, provide more specific guidance on this question:

> "…we find that compliance with the utility purchase obligation, by means of a purchase that would displace power from the Four Dam Pool

> Initial Project, is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA. We make this finding because, as we have stated previously, there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements. Moreover, there is no obligation under PURPA for a utility to enter contracts to make purchases which would result in rates which are not 'just and reasonable to electric consumers of the electric utility and in the public interest' or which exceed 'the incremental cost to the electric utility of alternative electric energy.'" 16 U.S.C. § 824a-3(b) (1994). (footnotes omitted, emphasis added) *City of Ketchikan, 94 FERC 61,293 (March 15, 2001), pages 15-16.*

Thus, as FERC itself has recognized, we must balance the PURPA mandate that utilities are to purchase energy and capacity from QFs with the overarching requirement that electric utilities may only charge just and reasonable rates for the power they supply to their customers. In its December 15, 2003 comments on the proposed decisions, Ridgewood contends that FERC recently confirmed the PURPA purchase obligation mandate in 105 FERC 61,238 and 105 FERC 61,239 (Swecker QF orders), and that these rulings are applicable to our current situation here in California. While these FERC orders resolved a lingering dispute between a small wind QF[100] and a small cooperative utility,[101]

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[100] The wind QF at issue is only 65 kilowatts (kW) in size and as such is subject to PURPA's standard rates requirement for QFs that have a design capacity of 100 kW or less, as set forth in 18 CFR 292.304 (c):

> "Standard rates for purchases. (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less."

the Swecker QF orders do not necessarily provide useful or dispositive guidance for our detailed and complex situation here in California where utilities with millions of customers and tens of thousands of megawatts of load have excess power in many hours.

As set forth in detail in all three proposed decisions, we have appropriately found the relevant guidance in FERC's *Ketchikan* and *Cogen Lyondell* orders. However, Ridgewood chose not to address, either order. Instead, Ridgewood relies exclusively on the Swecker QF orders. This Commission has acted in the past consistently with the holding in FERC's Swecker QF orders; indeed, we affirmed our implementation of the policy on PURPA's standard rates requirement for small QFs in D.96-10-036, Ordering Paragraph 7.

In light of the foregoing legal and policy considerations, it is now appropriate to consider our options with regard to several distinct groups of QFs: (1) Existing QFs with existing utility contracts, (2) Existing QFs with expired, or soon-to-be expired, utility contracts, and (3) New QFs with possible future utility contracts.

(2) Existing QFs With Existing Utility Contracts

None of the three utility proposals on QF issues would affect or impair existing QF contracts. This is, of course, in stark contrast to the *Cogen Lyondell* case wherein the Texas PUC sought a complete waiver of the PURPA

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[101] "Midland Power serves approximately 8,600 households, businesses and organizations that purchase more than 208 million kilowatt-hours annually" [roughly corresponding to a system capacity of 20 megawatts (MW)]. Source: http://www.midlandpower.com/asp/AboutUs/.

purchase obligation for all its QFs, both existing and new. We will continue to uphold existing QF contracts.

(3) Existing QFs With Expired, or Soon-to-be Expired, Utility Contracts

In D.03-12-062, we directed the IOUs to extend expiring or expired contracts with existing QFs for another year until December 31, 2004. However, that order only covers a very limited number of existing QFs, and the larger policy questions arising from the fact that many of the state's QF facilities have contracts that will be expiring over the next several years remain to be addressed.

On the issue of whether to renew existing QFs with expired, or soon-to-be expired, utility contracts, the three utility proposals, already discussed in some detail, do differ from one another.

Of the three proposals, SCE argues in the extreme that renewal of existing QF contracts is not necessary and that QFs can instead compete in any upcoming power solicitation proposals that maybe offered in the future. Under SCE's paradigm, determinations of need might be made from time-to-time as the utility issues RFOs for power under certain quantity, quality, and duration parameters; in addition, instead of plainly stating its need in the form of an exact quantity, the utility might be expected to simply specify acceptable bidding units of, for example, anywhere from one megawatt to 25 MW, or more in order to avoid revealing its exact net short position.

The SCE proposal appears to us to be inconsistent with a long-term, integrated resource planning process. SCE's "solicitation-only" opportunity for existing QFs to renew existing contracts that are expiring may technically comply with PURPA, but it does not fit well within the context of a long-term planning process of the type that is at the heart of this procurement proceeding. In this proceeding, we are reviewing proposed 20-year plans. By 2008, SCE will have a need for baseload power, which results, at least in part, from the expiration of QF contracts. Although the need for baseload power does diminish in the near-term, due in large part to the existence of the DWR contracts, we note that there is a need for power that materializes as existing QF contracts expire. Renewal of existing QF contracts should accordingly be encouraged, so long as they are priced within the range of comparable replacement power, to the extent that they can meet the IOUs' need for power.

The IOUs have proposed to comply, in whole or in part, with their PURPA purchase obligations by allowing QFs, including existing QFs with expiring contracts, the opportunity to participate in power solicitations. A competitive all-resource bidding process is an optimal means for an IOU to determine what resources can best meet its need for additional capacity. Ideally, QF participation in such solicitations is the best way for the IOUs to match their need for <u>new</u> capacity with the range of potentially available resources, including QFs. However, we do not believe that such participation should be mandatory for existing QFs seeking to renew their contracts.

In light of the continuing need for most of the power that QFs currently provide and for the other benefits of QF power, we do not think that IOUs proposal is sufficient.

Given the importance of the need to match an IOU's actual power needs with the nature of the resource being offered by certain QFs, there is one important element of the IOUs' competitive bidding processes that is highly relevant to the terms of future renewed contracts for existing QFs, namely, the use of such bidding processes to establish the value of the capacity provided by QFs. The price for new capacity that results from a competitive all-source bidding process is one way for an IOU to identify the basis for establishing the capacity payment that an existing QF seeking to renew a QF contract should receive. Accordingly, the results of the competitive all-source bidding processes that the IOUs have already undertaken, or will shortly undertake, will greatly assist in updating the value of the capacity component of the total SRAC that QFs are entitled to be paid pursuant to PURPA and state law. As was discussed in D.03-12-062, it is important that the current methodologies to establish QF pricing be modified and the Commission will be moving forward to examine and propose appropriate modifications to the QF pricing methodology in the near future.

Another option for determining the appropriate price to be paid for QF power emanates from the renewable portfolio standard provisions established in statute. The RPS provides for identification of a market price referent as discussed earlier in this decision. That market price referent, designed to approximate the market price of power, could form a proxy for the price at which QF power should receive a contract renewal. In our examination of QF pricing methodology going forward, we will invite parties to comment on this option for QF pricing.

We understand that most of the existing QF contracts will not expire until the end of 2005, and we expect that our review of the QF pricing methodology will be completed well in advance of that date. However, there may be some QF contracts that expire after December 31, 2004 but prior to the completion of that review. Since the resolution of the key questions relating to how QFs will be paid on a going-forward basis must await the completion of our review of the QF pricing methodology, we should continue to provide interim treatment, as we did in Decision D.02-08-071 and D.03-12-062, for QF contracts expiring prior to the completion of that review for which the QF and the utility do not reach agreement on the terms of a new long-term QF contract.

We are hereby extending the determinations we made in D.03-12-062 with respect to existing QFs with expiring contracts for up to an additional year, such that the utilities are obligated to continue to purchase power from any QF pursuant to an SO1 contract under the following conditions:

- The QF must have been in operation and under contract to provide power with an IOU at any point between January 1, 1998 and the effective date of this decision; and
- The QF contract must be set to expire before January 1, 2006, or have already expired.

In D.02-10-062 and D.03-12-062, we only required utilities to enter interim SO1 contracts of one year in length. In this order, however, we are persuaded by CCC and CAC/EPUC that a one-year SO1 contract is not sufficient to accomplish some of our goals.

In particular, we wish to encourage existing QFs to continue providing power over the longer term to the utilities. We also wish to encourage efficiency upgrades to existing facilities. Neither of these objectives will be met if we continue to offer only stopgap solutions in the form of one-year SO1 contracts.

Therefore, we will require the utilities to sign SO1 contracts of five years in duration with QFs wishing to provide power at SRAC prices. This is shorter than the duration suggested by CCC, owing to our uncertainty about power needs in the long-term and the fact that we have not yet adopted the utilities' long-term plans. Making the contracts five years in duration corresponds to the length of the utilities' general authorization for contracting, with the exception of renewables contracts.

The pricing terms for any such contract should be consistent with existing Commission SRAC policy established in D.01-03-067, as modified by D.02-02-028; provided, however, to the extent that the Commission adopts a revised QF pricing policy at any time prior to December 31, 2005, the pricing terms of the contract shall be modified to reflect said revised QF pricing policy as of the effective date of the Commission decision adopting a revised pricing policy.

Thus, as to existing QFs with expired, or soon-to-be expired, utility contracts, we conclude that the potential anomaly between the nature of the power offered by a QF and the actual system needs of an IOU can be resolved in any one of three ways: (i) voluntary QF participation in IOU competitive bidding processes; (ii) renegotiation by the QF and the IOU on a case-by-case basis of contract terms; and (iii) five-year SO1 contracts with the understanding that appropriate revisions by the Commission to the QF pricing methodology will flow through to the renewed contracts. Compliance with any one of these three alternatives should assure fairness both to the QF community and to the IOUs and their ratepayers.

(4) New or Modified QFs With Possible Future Utility Contracts

In its December 15, 2003 comments on the proposed decisions, Ridgewood argued that the disparate treatment of new and existing QFs in the proposed decisions should be eliminated. We have attempted to eliminate any such disparate treatment, as the following discussion shows.

As FERC stated in *Ketchikan*, "…we find that compliance with the utility purchase obligation, by means of a purchase that would displace power … is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA. We make this finding because, as we have stated previously, there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements."

This being said, we reaffirm what we have stated in previous decisions, namely, that QF power provides significant benefits to the state. We must accordingly find a reasonable middle ground between the positions of the IOUs, on the one hand, who seek to relegate new QFs to only being able to participate in competitive procurement processes, and QF parties, on the other hand, who assert an unlimited right to supply power to IOUs regardless of need.

We accordingly find that a new QF proposing to provide power in a manner that tracks the utility's actual needs would, under PURPA, be entitled to an agreement to provide the energy and capacity actually needed by the utility.

For the moment, our policy focus is on retaining the existing QF power already under contract, and improving its efficiencies. Thus, we decline to require that the utilities offer standard contracts to new QFs. We may revisit this decision once our reevaluation of QF pricing methodologies is complete.

We want to reassure the QF community that this action is in no way intended to close off all avenues for potential new QFs to obtain contracts with IOUs during the time between our adoption of this Decision today, and that date in the next year or so when we shall adopt a decision modifying QF pricing.

Specifically, we hold that a potential new QF may still obtain a contract from an IOU during the intervening period in two of the same ways as existing QFs with expired or expiring contracts, namely: (i) voluntary QF participation in IOU competitive bidding processes; and (ii) negotiation by the QF and the IOU on a case-by-case basis of non-standard contract terms.

Moreover, in connection with our consideration of appropriate revisions to the QF pricing methodology, we shall consider whether Standard Offer contracts, or some other instrumentality, should be available to potential new QF providers, and what specific form such contracts or instrumentalities should take. Thus, in our future decision modifying the pricing methodology, we expect to provide a mechanism whereby potential new QFs will be able to obtain a contract to provide power to an IOU without having to participate in a competitive procurement process, and without having to negotiate an individual bilateral contract.

With regard to any concerns that the QF community might have with respect to participating in IOU competitive bidding processes during this intervening period, we note that in this decision, we indicate that future procurement activities of the IOUs are to be conducted with much greater transparency than has been the case in the past. Thus, potential new QF power providers will be in a much better position to know what the power needs of the IOUs – which they would be seeking to satisfy – are likely to be. Furthermore, after completion of our upcoming pricing review, potential new QF power providers will also have accurate information on what the avoided costs prices that they will receive are likely to be. With this information, potential new QF power providers will be able to accurately assess the value and benefit to them of providing new or additional power to the IOUs. This approach provides fairness both to the QF community and to the IOUs and their ratepayers.

(5) PG&E's Curtailment and True-Up Proposals

In D.03-12-062, we rejected PG&E's 1,000-hour curtailment proposal. However, we need to address one remaining point regarding this proposal, namely that physical curtailment of QFs will provide unacceptable negative impacts on QF operations, which, in turn, could have the effect of discouraging existing QFs, on which the state does rely for power, from continuing in business. In this regard, we note that PG&E's witness, Pappas, did acknowledge that such curtailment would be both financial (*i.e.*, no payments would be made to QFs in certain hours) and physical (*i.e.*, QFs could even be prevented from physically letting free power flow on to the grid, which would force some QFs to back down on-site operations)] (p.4-5).

We also decline to adopt PG&E's request for true-up. We agree with IEP that PG&E's proposed true-up is inconsistent with established Commission precedent whereby QF prices have always been set prior to delivery.

C. Performance Incentives for Procurement Activities

1. Parties' Positions

In D.02-10-062, we expressed our preference to adopt a uniform incentive mechanism to provide an opportunity for utilities to balance risk and reward in the long-term procurement process. We directed SDG&E to sponsor, in coordination with the other utilities, an all-party workshop to develop an incentive mechanism proposal for utility electric procurement, including the energy efficiency component. SDG&E held several workshops on the issue resulting in the identification of key principles for an incentive mechanism. No consensus was reached by the utilities on specific incentive proposals and no proposals have been filed for our review.

At the hearing, many parties testified on this issue. The CEC supports the Commission's adoption of an "incentive mechanism that motivates utilities to pursue CPUC objectives at both the planning and operational stages of procurement." (Jaske, 6/23/03, p. 27.) SDG&E cites in its workshop status report statement that although no consensus for uniform incentives was reached, it will continue on to develop its own SDG&E proposals with several of the parties to the workshop process. SCE states that it has developed a DSM incentive mechanism that it is prepared to file in the new phase of this proceeding.[102] PG&E proposes a specific incentive structure for energy efficiency programs only, urging the Commission to adopt it proposal. NRDC supports utility incentive mechanisms urging the Commission to adopt these in this procurement proceeding as apart of a universal procurement incentive program

[102] SCE-LTP-Rebuttal, p.100.

(LTP/STP testimony - p. 20), with a particular focus on rigorous measurement and verification of program impacts for energy efficiency activities. (ORA LTP testimony, p. 59) and TURN (Opening Brief, p. 13) oppose utility incentives in the procurement proceeding and specifically urge the Commission to address incentives for energy efficiency in the energy efficiency Rulemaking 01-08-028. TURN further notes (Opening brief, p. 12) that "neither the issue of administration of energy efficiency programs, nor the issue of the appropriateness of any incentive payments, was adequately analyzed and debated in this proceeding."

2. Discussion

Incentive mechanisms for both supply- and demand-side options present the complex problems of a potential to design a "one-scheme-fits-all," mechanism that may not be appropriate to all parties. We laud SDG&E's efforts to identify principles and mechanism for comprehensive incentive mechanisms that cover both generation and non-generation resources. Nonetheless, we concur with TURN's comments that we do not have an adequate record on this issue with which to decide the issue.

Rather than simply adopting specific incentive mechanisms for particular resources (i.e., energy efficiency or demand response), we prefer an integrated incentive mechanism that rewards utilities for proper balancing of preferred resources, as identified in the Energy Action Plan "loading order" as well as D.02-10-062. We may choose to offer additional incentives if utilities meet or exceed particular targets set in other proceedings addressing the particular resources, but also believe that an overall incentive mechanism for proper portfolio balancing and management is important to establish.

Thus, by today's decision, we do several things. We refer the issue of incentives specific to energy efficiency to R.01-08-028 for disposition in that rulemaking. We take this approach due to the complexity of the topic, the need to develop a more comprehensive record on this issue, and the need for a focused effort that encompasses the entire energy efficiency portfolio authorized by this Commission.

As discussed in this decision, we are also addressing in R.01-08-028 the issue of what administrative structure should be in place for energy efficiency development in the future. Therefore, the incentive mechanisms for energy efficiency proposed by parties in this proceeding, along with others that we will consider in R.01-08-028, must be evaluated in the broader context of what role the utilities will play in program administration in the near and long-term. Moreover, as the Assigned Commissioner in R.01-08-028 observes:

> "Once the Commission articulates program goals for reducing energy consumption, it will need rigorous measurement and evaluation activities in order to assess our progress towards meeting those goals. In addition, if the Commission decides to award incentives for superior performance in meeting or exceeding energy efficiency goals, the Commission will need assurance that the reported performance is accurate. In both instances, rigorous evaluation is necessary." (Assigned Commissioner's Ruling Proposing Direction and Scope for Further Rulemaking, R.01-08-028, July 3, 2003, p. 10.)

We intend to evaluate and update existing measurement protocols for this purpose in R.01-08-028. Today's referral of the efficiency incentives issue to our energy efficiency rulemaking recognizes that any development of energy efficiency incentive mechanisms is also linked to the measurement issues being addressed in that forum.

Accordingly, in recognition of the interrelationship among the various issues currently being considered in R.01-08-028, and the issue of energy efficiency incentives, we request that a further PHC be held as soon as practicable in R.01-08-028, the purpose of which would be to address the scope and schedule of the issues identified in the July 3 ACR in light of today's decision to also refer the consideration of energy efficiency incentives to that proceeding.

To the extent that any utility wishes to propose an incentive mechanism for demand response separately, that issue should be considered in the demand response rulemaking (R.02-06-001) or its successor.

We continue to support the development of an overall incentive mechanism as discussed above. As such, that issue will further be considered in the next procurement rulemaking with a goal of having a mechanism adopted in time for procurement beginning in 2005.

D. Other Proposals

1. CPA Peaker Initiative

CPA notes that it is charged statutorily with insuring that electricity reliability is maintained by providing financing for power plants, efficiency, and renewable resources that meet this charge. The Agency carried out a rulemaking (2002-07-01), culminating in a final decision (D.03-001) in January 17, 2003. In D.03-001, the CPA finds that "Each utility should demonstrate to its appropriate regulatory body, and to others as required, that the utility owns, controls or reliably can acquire capacity that is expected to be available to the utility to reliably serve its load."[103] Further, the CPA finds that

[103] CPA Decision D03-001, pages 5-6.

dependable capacity should equal 117-percent of monthly peak load, resulting in a reserve ratio of 17-percent. The decision states:

> "The Power Authority expects that the reasoning and information stemming from this rulemaking will offer helpful guidance to the appropriate regulatory bodies when considering procurement policies and deciding whether or how much to differ from these recommendations based on their particular circumstances. The Power Authority also notes that this rulemaking was cited in the recent Procurement Decision in CPUC Proceeding R01-10-024; and provides this Final Decision as further input to that ongoing proceeding."[104]

In D.03-001, the CPA also finds that reserves are not adequate in California:

> "The Power Authority believes that up to this time, the evidence favoring the need for additional reserves is convincing. Documented withholding, exercise of market power, and rotating outages during the past two years provide stark evidence that the new paradigm brings a host of issues not envisioned under the previous scheme. Some level of additional dependable capacity, along with clear assignment of responsibilities is the best way to manage this new set of problems. The Power Authority intends to visit this reserve target recommendation each year, as it reviews its Energy Resource Investment Plan. There will be ample opportunity at that annual review to adjust targets as needed to compensate for improvements in the market structure."[105]

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[104] Page 29.

[105] Page 37.

CPA's Energy Resource Investment Plan – 2003-2004 was issued in final form on June 27, 2003. That document makes explicit conclusions about the need for more capacity in California, and it is that document that enunciates the proposal for new peaking capacity:

> "The CPA has initiated an effort to increase the Statewide electricity reserve margin to ensure reliability and reduce peak price volatility. The goal is to obtain up to 300 MW of new efficient peaking resources under CPA ownership, with the power output to be provided ***at cost*** for California's electricity consumers. The CPA invited proposals from generators that meet three primary criteria: lowest cost, proximity to reliability-need areas, and earliest on-line date."[106]

CPA also notes that its policy and strategic contributions include a commitment to:

> "[C]ollaborate with the CPUC, CEC, and investor-owned utilities during 2003 regarding the resource plans and specific procurement strategies by the IOUs. The CPA's focus will be on ensuring that environmentally responsible and cost-effective options are considered for meeting renewable energy, localized reliability, and demand response resource needs. CPA may be able to offer ownership and/or financing solutions to achieve these needs."[107]

The testimony and brief of CPA emphasize that action is needed now to bring on new peaking capacity by the summer of 2005 to lessen the risk of

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[106] CPA Energy Resource Investment Plan – 2003-2004, page 27. Emphasis in the original.

[107] Page 33.

another cycle of high and uncontrollable spot market prices and blackouts. The benefits to consumers of CPA's peaker initiative include (1) current conditions that are very favorable to plant construction; (2) the ability of CPA to help shore up investor confidence in California, (3) bolster in-state reserves; and (4) reduce RMR and other locational costs. CPA also asserts that there would be a benefit to the utilities having access to one-hundred-percent debt financing through the public power sector of the municipal bond market.

TURN supports the Peaker Initiative arguing that contracting for peaking capacity may be better than the utilities' current practice of purchasing 6-by-16 power contracts. Moreover, TURN favors CPA's low-cost financing options and favors the public investment aspect of the initiative, stating "All customers benefit from a more reliable system, but investment in such resources may not be profitable for the private sector because of the sporadic use of these units."[108]

CEC states that the peakers "could be a desirable resource addition"[109] under certain circumstances, but finds the CPA has not demonstrated those circumstances as part of CEC's 2003 IEPR analyses. ORA finds that CPA has not made a particular showing in this record that peaker plants are necessary to support California's future electricity needs.

PG&E and SCE mounted a vigorous opposition to CPA's initiative. PG&E states that CPA's proposal for 300 MW of new peakers should be rejected because no need for them has been demonstrated, they are not cost-

[108] TURN Opening Brief, page 17.

[109] CEC Opening Brief, page 20.

effective, and they do not meet the stated objective of enhancing local reliability. SCE argues that the CPA process that determined the need for the peakers was deficient, that the CPA would force the utilities to take the contracts without recourse for damages, and that the CPA itself would face no risk for construction costs for the plants. We note, however, that in the context of renewable procurement discussed above, the utilities argue that they have need for peaking resources. These positions are potentially inconsistent, and demonstrate the need for further exploration of the peaking needs of the utilities both for renewable and non-renewable power.

WPTF argues that the Peaker Initiative "jumps the gun"[110] on the resource adequacy issue and pre-defines the solution. WPTF would rather the utilities put their future needs out to bid after resource adequacy is fully defined.

Based on the record here, we do not find that there is a sufficient showing to determine whether or not 300 MW of additional peaker capacity to be operational by 2005 is needed, either in the service area of PG&E or in the service area of SCE. It may be the some portion of the 300 MW proposed would represent prudent investment for PG&E and/or SCE. It may also be that some of the peaking capacity needs can be met through other means, including transmission upgrades or renewable procurement. However, the long-term peaking contracts proposed by the CPA potentially represent cheaper peaking alternatives and should be considered fairly by the utilities.

Therefore, we direct the utilities to consider the CPA Peaker Initiative by presenting an objective analysis of their peaking needs, and

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[110] WPTF Opening Brief, page 42.

alternatives for meeting those needs, in their long-term plans. There is no reason that the utilities should reject the CPA Peaker Initiative out of hand simply because they did not control the RFP process. In that context, it may be reasonable for the utilities to enter into good faith negotiations with CPA for PPAs tied to specific power plants at specific prices for some or all of the proposed projects. We also direct the utilities to work cooperatively with CPA in areas where the utilities see a need to finance projects and the CPA can provide a favorable financing source.

2. City of San Diego's Proposal

In its testimony, the City of San Diego requests that the Commission allow cities to serve their own load with renewable energy, where the renewable generators are owned by a city and located distant from the load being served. City of San Diego witness Monsen describes the proposal, stating:

> "Cities with developable sites for renewables should be able to serve their own loads (i.e., loads for city facilities) with renewable energy, even if loads are at locations that are remote from the renewable generation." (Testimony at p. 10.)

Witness Monsen further states:

> "[T]he net metering treatment chaptered through Assembly Bill 2228 for dairy farm operations, if extended to include multiple sites and multiple generators, could serve as a model for such a crediting system." (Testimony at p. 11.)

It appears the proposal would allow retail credit for renewable generation against a distant customer site, an accounting method similar in concept to the method used for on-site generation under existing net metering tariffs. However, those tariffs, including those implementing the pilot program under AB 2228, allow customers to net generation against consumption only at a single customer site. The current tariffs are not intended to permit such net accounting for multiple or remote sites.

We will neither modify net metering tariffs nor reinterpret the intent of the Legislature with respect to net metering law in this proceeding. Any changes to net metering tariffs should be considered in the distributed generation rulemaking, where those changes may be considered in the context of broader distributed generation policy, including ratesetting and cost allocation issues.

D.03-02-068 addressed retail sales by a generator to a customer on the same distribution circuit, and did not adopt a distribution-only tariff. The City of San Diego proposal alludes to the use of high voltage transmission lines, which are located “in close proximity to these parcels of land.” (Testimony at p. 11) This suggests that the facilities would utilize transmission facilities in addition to the distribution facilities used to serve the load. The proposal also refers to a “means to transmit power from these remote locations to [the city’s] loads,” while remaining silent on the impacts (such as costs) associated with use of transmission and distribution facilities.

Since direct access transactions have been suspended,[111] new transactions of the type proposed by the City of San Diego between non-utility generators and consumers that utilize utility facilities are not allowed. Thus, there is currently no means for customers to serve their own loads with remotely

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[111] See D.02-03-055 and Water Code § 80110.

sited generation. For the foregoing reasons, we do not adopt the City of San Diego's proposal.

3. CAC/EPUC's Request for Clarification of Net v. Gross Load Calculation

A major issue during the hearings was the appropriate calculation of reserve requirements for Qualifying Facilities and other on-site generation. The issue involved whether reserve requirements should be calculated on a "gross" or "net" basis. The distinction between "gross" and "net" load is that "gross" load includes the on-site load served by the generator while it is operating, whereas "net" load excludes this on-site load and looks only at energy that is delivered to the grid.[112] Prior to the end of the hearing on August 12, 2003, FERC issued a final order where the issue of gross versus net determination of operating reserves was litigated.[113] In its order, FERC "[A]ffirm[ed] the judge's finding that the long-standing practice in the CA ISO control area of scheduling, metering and procuring reserves on a net load basis should be permitted to continue, so long as a QF has contracted for standby service with a [Utility Distribution Company ("UDC")], *i.e.*, a contract that provides for the immediate replacement of energy in case of the QF's forced outage."

Based on FERC's decision, all parties (including the ISO which was one of the stronger advocates for use of the "gross" approach)[114] have agreed that

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[112] Tr. (Pettingill) at 4378-4381.

[113] *California Independent System Operator Corporation*, 104 FERC ¶ 61,196 (August 12, 2003) in docket Nos. ER98-997-000; ER98-997-002; ER98-1309; ER02-2297-001; and ER02-2298-001.

[114] ISO Opening Brief, p. 73.

the use of the "net" approach is appropriate for those resources that contract with the utility for stand-by service. We will therefore adopt this approach. In doing so, we note that adoption of this approach may have only minimal effects on the utilities' procurement needs. For example, in reviewing the utilities' filings, it appears that they already implicitly discount QF availability by using historical deliveries to the grid.

The Joint Parties Interested in Distributed Generation/Distributed Energy Resources (Joint Parties) argue that the same "net" treatment should apply to distributed generation.[115] Provisionally, we agree. However, since the Commission has stated its intention to soon open a new rulemaking into the issue of distributed generation, we will revisit this determination in that proceeding.

VI. Procedural Process and Schedule for Future Filings

A. Long-term Procurement Plan Filings

SCE proposes that its long-term plan be reviewed on a three-year cycle, in coordination with its general rate case. Specifically, SCE proposes that each utility develop and submit a long-term integrated resource plan within 90 days of the final decision in its respective GRC. This would allow its plan to incorporate those issues resolved in the GRC. Further, SCE states that the Rate Case Plan (D.89-01-040, as modified) already contemplates submission of long-term resource plans as part of the utility's GRC showing.

[115] Joint Parties Opening Brief, p. 15.

In comments on the proposed decisions issued by ALJ Walwyn and Commissioner Peevey, the CEC specifically opposes the adoption of SCE's proposed triennial long-term plan filing schedule. The CEC argues that a triennial cycle will needlessly disconnect utility planning from the CEC's biennial IEPR process:

> "The triennial cycle virtually guarantees that most of the time an IOU will want to propose its own analyses as the base case, rather than use the IEPR results, and do so simply because their analyses are fresher than the IEPR results."[116]

The CEC also argues that if utility long-term plan filings are staggered to follow a GRC cycle "…there will be no consistent 'lead or lag' between any IOU [plan filing] and the IEPR."[117] The CEC further states that staggered long-term plan filings will undermine opportunities to achieve what should be common policy and practices among the three IOUs.

ORA and the ISO also oppose a staggered GRC cycle approach and articulate similar concerns voiced by the CEC.

We intend to review and adopt revised long-term procurement plans for the three utilities in our new Procurement OIR in 2004. With respect to the filing schedule for long-term plans submitted after 2004, we find the arguments made by the CEC, ORA and TURN against adopting SCE's proposed filing schedule to be compelling. A staggered GRC filing schedule will inappropriately disconnect the utilities planning efforts from the CEC IEPR process and is likely

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[116] Comments of the California Energy Commission on the Proposed Decisions of Commissioners Peevey and Administrative Law Judge Walwyn, December 5, 2003, p. 4.

[117] Ibid.

to result in duplicative and wasteful efforts on the part of PUC staff and interveners as result of having to review and litigate filings in three separate GRC proceedings. To achieve efficiencies in the commitment of staff and parties' resources, we will require the three IOU long-terms plans to be vetted in one proceeding sharing the same procedural track. We also find that taking this approach will better ensure appropriate coordination with the CEC's IEPR process as well ensure that our policies regarding utility resource planning are coordinated and consistent among the three utilities.

Following our decision adopting revised 2004 long-term procurement plans, the IOUs shall file long-term plans on a biennial cycle (on a date to be determined) that follows the CEC's adoption of a final IEPR report. In our decision on the revised 2004 plans, we shall revisit the specific timing of the IOUs' next round of long-term plan filings.

B. ERRA Filings

ORA and SCE recommend that the Commission annually update the short-term procurement plans in each utility's ERRA filing. In addition, PG&E, SCE, and SDG&E have all indicated in their ERRA filings that efficiencies could be made in the procedural process we adopted in D.02-10-062, especially with forecasts established closer in time to the applicable year, a combining of the forecast, reasonableness review, and ERRA true-up in one application for each utility, and the possibility of the ERRA trigger amount being handled by Advice Letter rather than application.

Outlined in the tables below are the ERRA schedules for 2004 and 2005, as presented in the ALJ Walwyn PD, mailed on November 18, 2003. In its comments on the ALJ Walwyn PD, ORA stated that the ERRA schedules in the PD are inconsistent with AB 57 because the schedules do not incorporate a semi-annual review of the power procurement balancing accounts, as ordered by AB 57.[118] We clarify here that our intent is to have the IOUs use the ERRA Forecast and Reasonableness Review applications as semi-annual opportunities to make a showing that the Commission needs to review the power procurement balancing accounts and adjust rates or order refunds. Therefore, we adopt the 2004 and 2005 ERRA schedules as originally proposed and outlined below.

2004 ERRA Schedule				
IOU	2004 ERRA Trigger AL /1	2004 ERRA Forecast	2003 Reasonableness Review	ERRA Over/Under Collection True-up /2
PG&E	April 1,2004	August 2003	August 2003	N/A
SCE	April 1, 2004	October 2003	October 2003	N/A
SDG&E	April 1, 2004	December 2003	December 2003	N/A

Footnotes:
1/ The trigger advice letter is used to calculate the ERRA trigger/threshold amount and is based on 12-months (calendar) of prior year recorded data. The IOU's will refile AL if Reasonableness Review Decision modifies recorded data. Note: By April 1, 2004 the IOUs will have closed their books for 2003 and filed their SEC reports.

2/ ERRA over/under collection true-up is independent of when IOUs file ERRA Forecast or Reasonableness Review applications–The IOUs will file an expedited application for Commission approval in 60 days when the ERRA balance reaches the trigger/threshold amount calculated in the Trigger AL.

[118] Assembly Bill 57 Section 454.5(d)(3).

2005 ERRA Schedule				
IOU	2005 ERRA Trigger AL /1	2005 ERRA Forecast /2	2004 Reasonableness Review /3	ERRA Over/Under Collection True-up /4
PG&E	April 1, 2005	June 1, 2004	February 2005	N/A
SCE	April 1, 2005	August 1, 2004	April 2005	N/A
SDG&E	April 1, 2005	October 1, 2004	June 2005	N/A

Footnotes:
1/ The Trigger advice letter is used to calculate the ERRA trigger/threshold amount and is based on 12-months (calendar) of prior year recorded data. The IOU's will refile AL if Reasonableness Review Decision modifies recorded data. Note: By April 1, 2005 the IOUs will have closed their books for 2004 and filed their SEC reports.

2/ The dates have been changed so the IOUs file earlier in the year. This will allow IOU/PUC to have decisions out by the end of the year.

3/ 2004 Reasonableness Review period will incorporate 12 months of 2004 calendar year data.

4/ ERRA over/under collection true-up is independent of when IOUs file ERRA Forecast or Reasonableness Review applications. The IOUs will file an expedited application for Commission approval in 60 days when the ERRA balance reaches the trigger/threshold amount calculated in the Trigger AL.

VII. Confidentiality

At the February 18, 2003 PHC, the Assigned Administrative Law Judge (ALJ) stated one of the objectives for the procurement proceeding's long-term planning process is to ensure that the public and interested parties can meaningfully participate in the proceeding and that the public can understand the basis for our decision. Towards that end, the ALJ outlined a procedural process by which the utilities would make a showing that their filed long-term plans do in fact provide for meaningful public participation. This process culminated with the issuance on April 4, 2003 of a Ruling from ALJs Allen and Walwyn that adopted guidelines governing the scope of information that shall be considered confidential in the utility's long-term plans filings.

Since issuance of the April 4 Ruling, parties have continued to voice concern over the amount of information that is shielded from public review. We also recognize that the Legislature, particularly the Senate Energy, Utilities and Communications Committee, has taken a strong interest in this subject and has pressed this Commission to expand the amount of utility resource planning and procurement data that is made publicly available, and to ensure that the public has meaningful access to the Commission's decision-making. In light of this ongoing concern and in an effort to promote the widest possible dialogue on utility planning matters in California, we will again revisit our approach to the treatment of confidential information in our new Procurement OIR. Our intent is to broaden the scope of information embedded in utility resource plans that can be made public.

We direct parties' attention to the 2003 Integrated Resource Plan of PacifiCorp (the PacifiCorp Plan), which was submitted to the regulatory commissions of the various western states in which it operates: Utah, Oregon, Wyoming, Washington, and Idaho (PacifiCorp also operates in California, but given its limited operations in the state, it is not subject to AB 57 requirements). This plan can be downloaded from http://www.pacificorp.com/Navigation/Navigation23807.html. The PacifiCorp plan provides considerable loads and resource information in its public plan. The extent of information made public in the PacifiCorp Plan appears to exceed the guidelines on confidentiality adopted in the April 4 Ruling and points to the need for a re-examination of our approach with a view towards making far more information public in the next round of long-term procurement plan filings.

We suggest the PacifiCorp plan as a possible model of transparency in resource planning and invite parties to comment on the merits of requiring its use by PG&E, SCE and SDG&E. In their comments, parties should specifically address whether and how California ratepayers could be harmed (*e.g.*, higher procurement costs) as a result of making public the same planning data as is made public in Utah, Oregon, Wyoming, Washington, and Idaho. Would California ratepayers be uniquely disadvantaged relative to ratepayers in other western states with regards to the consequence of expanding the breadth of publicly available planning information? Comments shall be due in this Docket within 30 days of the effective date of this Decision and will be incorporated and made part of the record in our new Procurement OIR, once formally instituted.

As a corollary to our intent to expand the scope of utility planning data that is made public, we also intend to revise the review procedures for new utility projects and power purchase agreements brought before the Commission for pre-approval. We are frustrated with our experience from last year over the amount of information that has been redacted in utility filings seeking pre-approval of certain procurement transactions. The breadth of the redactions we see in utility filings is incompatible with open decision-making. While there may be at times an inherent tension between open decision-making and the protection of confidential information, it is possible to balance these competing goals in the public interest. During the Commission's consideration of procurement issues both in this Docket and in related advice letter filings over the past year, some believe we have tilted this balance more toward the "protection of confidential information" than is required by the public interest. Indeed, based on this experience, we consider the current point on the continuum between these competing goals to have become unworkable, and are resolved to move much closer to the "open decision-making" end of the continuum.

Accordingly, in our new Procurement OIR, we intend to revise the review procedures for utility projects and power purchase agreements such that our decisions are made solely on public information provided by utilities and other suppliers. In particular, we will specify that all product, price, and availability information contained in the IOUs' procurement-related applications that are submitted for Commission approval be public information, to the extent possible, and not subject to confidentiality protections in the absence of a convincing showing that public release will harm ratepayer interests. As part of their comments to be submitted within 30 days of the effective date of this Decision, parties should specifically address the issue of whether and how California ratepayers could be harmed (*e.g.*, higher procurement costs) as a result of our making public all product, price, and availability information contained in the IOUs' procurement-related applications.

The IOUs also submit quarterly compliance filings pursuant to a previous Order in this Docket. These compliance filings contain details of all individual procurement transactions executed by a given utility during the previous quarter. To date, these compliance filings have been submitted under seal. The parties should address in their comments whether and how California ratepayers could be harmed by having all data contained in the IOUs' quarterly procurement transaction compliance filings be submitted as public information not subject to confidentiality protections.

VIII. Next Steps

In this decision, we adopt the long-term regulatory framework under which each utility will conduct integrated resource planning, including a resource adequacy requirement and market structure rules. We also adopt a revised ERRA procedural process.

We expect to complete all outstanding matters in this rulemaking by the end of May 2004. The outstanding matters are (1) the October 7, 2003 motion of SDG&E for approval to enter into new contracts resulting from its Grid Reliability Capacity RFPs; and (2) the resource adequacy workshops scheduled in Section IV.A of this decision that are needed for the utilities to file revised 2004 long-term plans.

We should open a new procurement rulemaking in the second quarter of 2004 that specifically addresses the additional procurement issues we identify here: (1) the need to develop procurement incentive mechanisms for each utility; (2) the need to develop a long-term policy for expiring QF contracts; (3) review of the management audits of SDG&E's and PG&E's electric procurement transactions with their regulated affiliates; (4) handling resource adequacy issues not addressed in the workshop process; and (5) review and adoption of revised 2004 long-term procurement plans for the three utilities, (6) treatment of confidential information.

IX. Oral Argument and Comments on the Proposed Decision

The proposed decision was mailed on November 18, 2003 for consideration at the Commission's December 18, 2003 agenda. Under the provisions of Rules 77.2-77.5, parties filed comments on the proposed decision on December 8, 2003 and reply comments on December 15, 2003.[119]

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[119] Parties filing comments are listed in D.03-12-062.

An oral argument before the Commissioners was held on December 2, 2003 and the Commission addressed issues needing resolution prior to January 1, 2004 in D.03-12-062.

We have reviewed the comments filed on the remaining issues and made changes where appropriate. The major areas of revision are in reserve requirements, QFs policy, 2005 operating authority, long term planning assumptions, affiliate transactions, and confidentiality.

X. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Christine M. Walwyn is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. PG&E, SDG&E, and SCE are the respondent utilities.
2. This decision addresses the procurement planning issues set for further hearing in Section X.B. of D.02-10-062 and further delineated at the PHCs on February 18, 2003, March 7, 2003, and July 16, 2003.
3. Implementation of SB 1078 and SB 1038 legislation on the RPS has occurred through a separate workshop process.
4. The three service territories of the respondent utilities account for approximately 80% of California's electricity usage.
5. An Assigned Commissioner/ALJ Ruling issued in this proceeding on September 25, 2003, directed the convening of workshops to address the issue of standardizing, to the greatest extent possible, the load forecasts and methodologies used by the utilities to value and count resources.
6. Given the strong interaction between resource procurement and resource adequacy it is desirable that California rather than federal regulators make the necessary decisions.

7. A poorly designed resource adequacy framework could needlessly limit the Commission's flexibility as well as usurp the Commission's statutory responsibilities. Therefore, the Commission has routinely advocated, in a variety of forums, that it should address resource adequacy and procurement issues.

8. The ISO has recognized that resource procurement is primarily a state function, adopting at its November 21, 2002 Board meeting a resolution to defer consideration of its resource adequacy proposal and directing ISO staff to actively participate in this proceeding.

9. There is a trade-off between reliability and least-cost service given the cost to acquire and retain reserves. As SDG&E calculated, each additional 1% increase in reserve level adds $2.8 million to its costs. Adjusting for SDG&E's smaller size, costs for SCE and PG&E would be significantly higher.

10. There is a broad range of resource applications and technologies that California can rely on to meet its reserve levels.

11. The Energy Action Plan, as well as the guidance given for this proceeding, established a "loading order" for new resource additions emphasizing increased energy efficiency, demand response/dynamic pricing, and renewable energy.

12. The development, timing, and calculation of a reserve level can have a significant effect in promoting (or deterring) development of these new resources.

13. An appropriate balance should be achieved between meeting reserve requirements expeditiously while seeking to optimize the resource mix/portfolio. Paradoxically, rushing to implement a reserve requirement might further increase California's reliance on natural-gas fired resources, posing a different set of reliability concerns if there are supply constraints and price risks for the fuel input.

14. While no party advocates extensive reliance on the spot market, most parties believe that it may be both reasonable and prudent to allow for some portion of resource needs to be met through the spot market, a practice that some utilities responsibly engaged in under pre-AB1890 resource procurement.

15. A key factor that needs to be considered in evaluating resource adequacy is the current state of the wholesale energy market in the West, and the degree to which California's utilities have obtained or can access these resources to meet their energy needs.

16. We find that there are ample resources for California to meet demand for 2004 as well as adequate resources available for California to meet peak demand through 2007.

17. The Joint Recommendation proposes a 15% planning reserve, phased in beginning 2005 through 2008 based on equal percentage increments (i.e., 2% per annum increase).

18. A 15-17% reserve level, to be phased in by no later than January 1, 2008, strikes an appropriate balance for ensuring reliable service by providing incentives to encourage the retention of existing resources, whereas setting reserves at a higher level could require the utilities to make short-term investment decisions inconsistent with the Energy Action Plan's preferred "loading order" of new resources.

19. It is reasonable to adopt a 90% level of forward contracting for summer (May through September) peaking needs for each utility at one year in advance. We should allow the utilities the flexibility to justify to the Commission, on a case-by-case basis, excursions below this level. It is appropriate to defer implementation of this requirement to 2007.

20. A 5% target limitation on spot purchase provide a balance between flexibility and reliability and it is reasonable to continue to require the utilities to justify any higher level.

21. The preferred approach is for California to address the resource adequacy at the state level.

22. California should receive full credit and value for the long-term contracts entered into by the DWR to help California meet its energy needs during the crisis.

23. The issue of deliverability is an issue that needs further study.

24. Utility contracts without specified delivery points should not be permitted.

25. The utilities should prioritize resource additions consistent with our direction in D.02-10-062 and the loading order of resources stated in the Energy Action Plan.

26. 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.

27. To the extent it is cost-effective, utilities should be looking to new generation capacity that is not powered by natural gas, currently the prime mover for 42 percent of the electric energy consumed in this state.

28. There is a need for the utilities to commit to new or refurbished generation capacity in the next few years.

29. Since the long-term plans were filed, SCE and SDG&E have made proposals to purchase and own new generation resources.

30. There is an opportunity today to acquire additional generation cheaply and, therefore, we should not delay in setting out clear market structure rules.

31. California has a long history of reliable service being provided by utility-owned and operated generation plant and a recent painful history of rolling blackouts and high price spikes from reliance on third-party generators in a poorly designed competitive market.

32. Third-party generating capacity, if contracted properly, holds a number of advantages for California ratepayers.

33. We find that a portfolio mix of short-term transactions, new utility-owned plant, and long-term PPAs is optimal, combining the security of generation assets under the full regulatory oversight of the Commission with the flexibility of ten-year contracts, and the potential benefits of operating efficiencies and lower costs from a competitive market.

34. Utilities may face challenges when trying to construct new plant as it has been twenty to thirty years since they built fossil-fuel plants.

35. The presumption that utilities may favor their own capacity at the expense of third-party generators is well founded.

36. Careful design and monitoring of a competitive solicitation process and use of a least-cost dispatch standard are important means for addressing the potential for bias.

37. The utilities should rely on the formal RFP process to secure future long-term generating capacity resources.

38. Utilities may always propose utility-owned and/or utility-built generation at any time if they feel that it can be competitive, but should be required to justify the reasonableness of such proposals, as well as proposals for cost containment.

39. We should allow the utilities the authority and opportunity to bid in solicitations conducted by generators offering capacity and/or energy.

40. A mix of contract lengths, sufficient to allow for new construction of power plants or transmission projects, is best.

41. Exhibits from last year's hearings show that there were only a limited number of disallowance decisions from 1980-1996, and that the majority of these decisions and dollar adjustments involved affiliate transactions.

42. The most direct and effective means to avoid any potential conflict of interest is to simply prohibit affiliate transactions. However, we will grandfather already existing contractual relationships with affiliates (e.g., QF contracts) for the life of the existing plant in order to ensure that existing resources with such relationships can continue to serve California. The holding companies and affiliates of each utility should plan for future generation investment to be made outside of the utility's service territory and sold to other load serving entities. Two exceptions we need to address are the gas storage and transportation transactions that SDG&E needs to conduct with SoCalGas and that PG&E may need to conduct with separate company departments and unregulated affiliates.

43. In D.02-10-062, we addressed the utilities' capability to meet their obligation to serve, and found that PG&E and SCE did not need to obtain an investment grade credit rating prior to resuming the procurement role.

44. Today, the three utilities have all successfully resumed full procurement and the financial prognosis for PG&E and SCE is much improved.

45. Debt equivalency is a term used by credit analysts for treating long-term non-debt obligations – such as PPAs, leases, or other contracts – as if they were debt in assessing an entity's debt capacity. The risk factor can be 0% to 100% of these contractual payments, depending on the type of obligation.

46. The Commission should address the impact of debt equivalency on the utilities' financial condition. The appropriate forum to address debt equivalency is in the Cost of Capital proceeding for each utility.

47. During 2004, the utilities need to begin the normal cycle for procuring short-term products for 2005. Purchases for 2005 should be limited to contracts of one year or less in duration.

48. A ten-year procurement planning horizon is appropriate and should provide relatively long notice to all industry players of the state's anticipated needs and allow them to respond appropriately.

49. Long-term plans should include expected load and energy requirements, not only at their expected, or median, levels, but also at the 95th percentile (that is, the one-in-twenty years case) of expected need levels. We also expect the utilities to continue to consider a core/non-core scenario in their forecasts. The utilities should also supply a range of forecasts of load in their revised 2004 long-term plans in order to account for potential changes in community choice aggregation and direct access.

50. As part of their long-term plans, the utilities should identify which procurement proposals will require environmental review, special permits, separate applications, or other regulatory procedures or proceedings.

51. The CEC's IEPR "information and analyses" should form the base case. If a utility does not find it appropriate to use that as its base case, it should include the IEPR case along with its preferred base case. The utility should report how and why the assumptions underlying its forecasts differ from those of the CEC forecasts.

52. The long-term plans should reflect the outcome of the workshops on reserve requirements. If that process is not concluded, the utilities should make their best estimate of the outcome of that process and estimate accordingly.

53. 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.

54. Future long-term procurement plans should reflect fully the expected range of fuel prices and purchased power costs at least up to the 95th percentile of the expected distribution.

55. SCE's revised long-term plan should contain scenarios both including and excluding the Mohave power plant to ensure that the future of this plant and A.02-05-046 are not prejudged.

56. Long-term plans should include not only the utilities' preferred portfolio choice for how to meet their needs, but also other portfolio alternatives/ variations to meet those needs. The utilities should present estimated ratepayer costs associated with each method of meeting their needs, and should include some metric of the variability of those costs.

57. In D.02-10-062, we expressed our preference to adopt a uniform incentive mechanism to provide an opportunity for utilities to balance risk and reward in the long-term procurement process.

58. We should refer future issues related to program duration and program cycles to R.01-08-028 for disposition in that Rulemaking.

59. We should refer the issue of administration of energy efficiency programs authorized in this proceeding to R.01-08-028.

60. We should refer the issue of the role of non-utilities in the delivery of the procurement-related energy efficiency programs authorized in this proceeding to R.01-08-028.

61. We should refer the question of potential financial risks associated with carbon dioxide emissions to R.01-08-028, to be considered in the context of the avoided cost 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.

62. Demand response, like energy efficiency, is a demand-side resource for the utilities. While energy efficiency resources can often meet baseload procurement needs, demand response can fill on-peak requirements.

63. In D.02-10-062, we directed that the demand response targets adopted in R.02-06-001 should be integrated into the utilities long-term plans.

64. In D.03-06-032, the Commission adopted demand response goals for each utility and directed that the IOUs include the MW targets for calendar years 2003 through 2007 in their procurement plans, specifically stating the filings in this proceeding should include: numeric targets coinciding with the findings in this decision; documentation of the amount of demand response (price-triggered) to be achieved by July 1 of each calendar year (with the exception of 2003, where the goals shall be met by the end of the calendar year); which programs and/or tariffs the IOU will rely upon to achieve the targets; and a contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals.

65. Funding for price-responsive demand response programs is also addressed in D.03-06-032.

66. It is difficult to compare and extrapolate the distributed generation forecasts from the utilities long-term procurement plans.

67. In guiding the utilities' long term planning process, we focus on developing an integrated resource approach, one that recognizes our policy priority for demand-side resource additions, and that optimizes generation and transmission resources.

68. There are about 600 Qualifying Facilities (QFs) under contract to PG&E, SCE, and SDG&E. These QFs supply power used to serve about one-fourth of the combined retail load for the three utilities.

69. The QF industry marked its beginning with the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978 which required utilities to purchase QF power under certain terms and conditions.

70. By 2008, expired QF contract capacity is expected to exceed 1,000 MW and approach 1,800 MW by 2010.

71. QF power provides numerous benefits to California, including environmental attributes, local power production, and economic development.

72. We encourage both the QF community and the IOUs to be creative and flexible in negotiating renewed contracts for existing QF facilities and new contracts for new facilities.

73. In D.03-12-062, we committed to reevaluating the pricing methodologies for QF power in the future.

74. In compliance with PURPA and recent FERC decisions, we should provide an opportunity for existing QFs to continue to provide power to the utilities in a manner that encourages facility maintenance and upgrade.

75. We find that there is a potential need for at least some of the 300 MW of additional peaker capacity proposed by the CPA to be operational by 2005, either in the service area of PG&E or in the service area of SCE.

76. We find that the long-term peaking contracts proposed by the CPA potentially represent cheaper peaking alternatives and should be considered fairly by the utilities.

77. We find that the CPA engaged in an objective and reasonable process for soliciting peaking projects, with the intent of providing the results to the utilities in good faith.

78. We should direct the utilities to present an assessment of their peaking needs in their long-term plans and to work cooperatively with CPA in areas where the utilities see a need to finance projects and the CPA can provide a favorable financing source.

Conclusions of Law

1. The Commission's legislative mandate is to ensure that all utility customers receive reliable service at just and reasonable rates, as specifically stated in Pub. Util. Code § 451 with § 701 giving the Commission power to undertake all necessary actions to properly regulate and supervise California's investor-owned utilities.

2. The Commission has authority to impose reserve requirements on non-utility load serving entities (such as Energy Service Providers) under Pub. Util. Code 394.

3. AB 57 and SB 1976, codified in Pub. Util. Code § 454.5, provides a regulatory procurement framework for the Commission.

4. In order to provide reliable service, each Load Serving Entity within PG&E's, SCE's, and SDG&E's service territories should have an obligation to acquire sufficient resources for their customers load.

5. In D.02-12-074, the Commission provisionally adopted a 15% reserve level subject to further revision in this proceeding. Based on the record developed in this proceeding, we should reaffirm and make permanent the 15 % reserve level, as well as allow for a range up to 17% to account for the lumpiness of investment.

6. A 15-17% reserve level also strikes an appropriate balance for ensuring reliable service by providing incentives to encourage the retention of existing resources, whereas setting reserves at a higher level could require the utilities to make short-term investment decisions inconsistent with the Energy Action Plan's preferred "loading order" of new resources.

7. The utilities should meet this 15-17% requirement by no later than January 1, 2008. In their procurement filings, the utilities should justify reserve levels above 15%, although we recognize that given the inherent "lumpiness" of resource additions, the utilities may acquire reserves above 15%, depending on the timing of the resource additions to meet demand.

8. Deferring to the ISO is inconsistent with both FERC and the ISO's stated policies of giving deference to the State to address resource adequacy issues.

9. Although the Commission chose to narrowly limit the exercise of its jurisdiction in implementing Pub. Util. Code § 394, it would be appropriate if the Commission were to decide that additional safeguards should be imposed upon ESPs under the requirements of Pub. Util. Code § 394.

10. Requiring ESPs to meet a reliability obligation, as allowed under Pub. Util. Code § 394, would not conflict with the "terms and conditions" under which direct access customers receive service.

11. Under existing law, the utilities remain both the default provider, and provider of last resort for all load within their service territories.

12. We should seek another round of comments, as part of this proceeding, as to how to assess and develop workable deliverability standards.

13. We do not have an adequate record on which to adopt an energy efficiency incentive.

14. AB 57 takes a neutral position on whether the utilities should own additional generation capacity.

15. We adopt these contract guidelines:

(a) For contracts for existing resources, the utility would have dispatch rights to specified resources. Contract language should state that only specific plants could provide the power, and perhaps ancillary services, with no allowance for substitution from the market; and

(b) There should be contractual arrangements such as step-in-rights and take-over type rights to address longer term issues of supplier nonperformance.

16. In D.03-06-076, the Commission found that the ban on affiliate transactions was properly noticed, jurisdictional, constitutional, violated no federal laws, and the record supported the need for a moratorium on utility procurement from its own affiliates until adequate safeguards are fashioned.

17. D.03-06-076 also sustained Standard of Behavior 1.

18. In allowing the utilities to directly participate in owning new generation facilities, we recognize that we will need to be vigilant in overseeing that no bias occurs in selecting, or dispatching the resources.

19. 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.

20. The holding companies and affiliates of each utility should plan for future generation investment to be made outside of the utility's service territory and sold to other load serving entities.

21. SD&E should file a revised Exhibit 70 to reflect that the risk management committee(s) overseeing SDG&E's electric procurement operations and DWR-related gas procurement operations are comprised solely of SDG&E management. This filing should be by Advice Letter within 30 days of the effective date of this decision.

22. A management audit to review whether negotiated transactions with SoCalGas should be subject to special transaction rules and reporting should be undertaken. The management audit should be narrowly focused on two issues: SEU's participation in the risk management committee structure for SDG&E procurement operations; and any rules or reporting needed for SDG&E's energy procurement transactions with SoCalGas. The Commission's Energy Division should draft the scope of work required, select an independent auditor, and oversee the analysis. At the conclusion of the analysis, an audit report should be filed with the Commission and served on all parties to this proceeding. The auditor should remain available to explain the report's findings, and testify in evidentiary hearings at the Commission on the findings included in the report. SDG&E should place the audit costs in a memorandum account.

23. In Res. E-3838, we apply the affiliate transaction rules to all procurement transactions between SDG&E and SoCalGas, and set an interim standard for transactions SDG&E enters on behalf of DWR with either itself or an affiliate for services which are paid on a negotiated basis. We should adopt this standard on an interim basis for all SDG&E's procurement transactions.

24. We should direct a management audit of PG&E's transactions for electric procurement for its customers and gas procurement for DWR contracts with other departments and affiliates.

25. We adopt here a permanent ban on affiliate transactions for procurement with the following exceptions:

(1) "Anonymous" transactions through approved interstate brokers and exchanges, provided that the solicitation/bidding process is structured so that the identity of the seller is not known to the buyer until agreement is reached, and vice-versa.

(2) Transactions for natural gas services between SDG&E and SoCalGas and between PG&E and affiliates and operating divisions that are found necessary and beneficial for ratepayer interests. These transactions should be subject to the rules adopted in Res. E-3838 and Res. E-3825 pending receipt and review of the management audits ordered here.

(3) Grandfathering of already existing contractual relationships with affiliates (e.g., QF contracts) for the life of the plant.

26. Each utility should make the investments necessary to meet their obligation to serve their customers at just and reasonable rates. Care should be taken not to make commitments that could later result in stranded costs.

27. We should authorize the utilities to procure for 2005 under the same operational authority contained in the adopted 2004 short-term plans, except that

authority for 2005 should be limited to the first three quarters, with contracting authority of up to one year in duration.

28. For their next long-term plan filings, all three utilities should include an appropriate level of long-term commitment to additional power plants or plant-specific purchase power contracts.

29. Revised long-term plans should be submitted and approved in 2004 and any long-term commitments brought to the Commission in the interim should meet a "no regrets" criteria.

30. The utilities should file by the end of March 2004, a working outline of their long-term plans that includes the level of detail and specific scenarios addressed in this decision, the means by which they will incorporate the resource adequacy framework developed through workshops, and a showing that the material provided in the public filing will allow for meaningful participation by all parties. Such plans shall meet all the requirements set forth in this decision.

31. In the revised 2004 long-term plans, the utilities should also provide a forecast of the percentage of retail sales met each year by renewables, indicating the projected year for achieving the 20 percent RPS target, and maintaining or increasing that percentage in future years. Each IOU should also modify its plan to include an accelerated RPS target renewables procurement scenario that evaluates any resulting changes to its overall energy procurement portfolio.

32. The utilities should include in their updated long-term plans several forecasting scenarios, including widespread formation of community choice aggregators, as well as a core/noncore scenario.

33. The utilities shall also update their 2004 and long-term plans to include interim procurement activity from 2003.

34. The utilities' 2004 revised 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.

35. We should not adopt the Joint Parties recommended approach for a set-aside because it could predetermine the outcome of a new rulemaking on distributed generation.

36. A minimum requirement for the 2004 revised long-term plans is that the IOUs work with the ISO on defining conceptual scenarios for resources imported into the ISO control area and deliverable to the individual IOU's load.

37. Renewal of existing QF contracts should be required for a minimum of five years, using the SO1 contract structure at existing SRAC prices. Such renewed contracts should include a provision that the pricing methodology may be modified by subsequent Commission action.

38. New QFs may seek to negotiate contracts with utilities under the following circumstances: (i) voluntary QF participation in IOU competitive bidding processes; (ii) renegotiation by the QF and the IOU on a case-by-case basis of contract terms that explicitly take into account the IOU's actual power needs and that do not require the IOU to take or pay for power that it does not need.

39. Changes to net metering tariffs such as City of San Diego's should be considered in the distributed generation rulemaking, where those changes may

be considered in the context of broader distributed generation policy, including ratesetting and cost allocation issues.

40. Since direct access transactions have been suspended, there is currently no means for customers to serve their own loads with remotely sited generation.

41. The use of the "net" approach is appropriate for those QF and other on-site generation resources that contract with the utility for stand-by service.

42. Each utility should meet and confer with its PRG on a quarterly basis.

43. Commission approval of the utilities' Procurement Plans does not preclude the need for DWR to conduct after-the-fact reasonableness reviews.

INTERIM ORDER

IT IS ORDERED that:

1. The utilities shall file by the end of March 2004 a working outline of their long-term plans that includes the level of detail and specific scenarios addressed in this decision, the means by which they will incorporate the resource adequacy framework developed through workshops, and a showing that the material provided in the public filing will allow for meaningful participation by all parties. Such plans should meet all of the requirements set forth in the text of this decision. A schedule will be addressed in the new Order Instituting Rulemaking.

2. In order to provide reliable service, each Load Serving Entity within Pacific Gas and Electric Company's, Southern California Edison's, and San Diego Gas & Electric Company's service territories should have an obligation to acquire sufficient resources for their customer load.

3. In the revised 2004 long-term plans, the utilities shall also provide a forecast of the percentage of retail sales met each year by renewables, indicating

the projected year for achieving the 20 percent Renewable Portfolio Standard (RPS) target, and maintaining or increasing that percentage in future years. Each IOU shall also modify its plan to include an accelerated RPS target renewables procurement scenario that evaluates any resulting changes to its overall energy procurement portfolio.

4. For Qualifying Facilities (QF)s with existing contracts expiring before December 31, 2005, the utilities shall offer five-year Standard Offer 1 (SO1) contracts at short-run avoided cost (SRAC) prices. The contracts shall include the provision that the pricing terms may change if the Commission subsequently modifies its policy on QF pricing methodology.

5. We revise the ERRA filings dates as set forth in the text of this decision.

6. The utilities shall present an assessment of their peaking needs and alternatives for meeting those needs, including analysis of the CPA Peaker Initiative, in their long-term plans, and work cooperatively with the CPA in areas where they see a need to finance projects where the CPA can provide a favorable financing source.

7. We direct utilities to submit programmatic energy efficiency proposals in Rulemaking (R.) 01-08-028 with energy savings and demand reductions goals equal to or greater than the energy savings and demand reductions forecasted in utility long-term plan forecasts.

8. We require utilities to present to the Commission in this rulemaking within twenty-days of this decision the methodologies they will use to ensure that forecasted measured savings of energy efficiency savings and demand reductions in utility long-term plans in this rulemaking are equivalent to the savings calculated for measures used in utility savings assumptions for procurement related energy efficiency programs submitted in R.01-08-028.

9. For purposes of meeting load requirements of 2005 in a seamless manner, the utilities are directed to provide updated forecasts of 2005 open positions by compliance advice letter within 30 days of the effective date of this order, and are authorized to procure for the first three quarters of 2005 under the same operational authority contained in the 2004 short-term plans adopted in D.03-12-062, except that contracts for 2005 need shall not extend beyond one year.

10. The utilities are permitted to participate in RFPs and/or open seasons conducted by generators offering capacity and/or energy.

11. Within thirty days of the effective date of this decision, interested parties should file comments addressing the confidentiality issues set forth in this decision.

This order is effective today.

Dated January 22, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President

CARL W. WOOD
LORETTA M. LYNCH
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I will file a concurrence.

/s/ MICHAEL R. PEEVEY
President