Decision **<u>REVISED PROPOSED DECISION OF ALJ</u>**

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

Today's decision is the first of two decisions to be issued in the Commission's ongoing procurement rulemaking following evidentiary hearings held during July and August of 2003. In today's decision, we decide issues which should be resolved prior to January 1, 2004, opting to address all other issues, constituting the remainder of the record submitted following evidentiary hearings, in a comprehensive policy decision to be issued after January 1, 2004.[1]

Today we adopt the short-term procurement plans (STPP) 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 operate in 2004. We adopt appropriate short-term reserve levels, and provide guidance on a target level of spot market purchases for this same period. We also address risk management issues, authorized contract term duration and volume limits, standards for procurement products and transactions, and the process for modification and approval of short-term plans. Our decision addresses the status of the current affiliate transactions prohibition, and continues the Procurement Review Group (PRG) for another calendar year. We also address (1) a limited set of Qualifying Facilities (QF) issues that must be decided now in order to assure the continuing availability of QF power during 2004; (2) funding, program

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[1] Pursuant to Pub. Util. Code Sections 311(d) and 311(e), the parties have filed extensive written comments on the issues to be addressed in both of these decisions. We have carefully considered these comments in our deliberations.

selection, and cost recovery issues related to energy efficiency programs for 2004 and 2005; (3) demand response issues; and (4) short-term renewables issues necessary to ensure that the 2004 plans are consistent with the Renewable Portfolio Standard (RPS). Finally, we provide necessary short-term guidance on certain procedural processes and filing requirements.

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 Department of Water Resources (DWR) contracts to each utility, established requirements for the procurement of renewable resources, established cost recovery mechanisms, and adopted STPPs under which the utilities operate through December 2003.[2]

Submitted for decision at this time are the procurement planning issues set for further hearing last year in Section X.B. of Decision (D.) 02-10-062. These issues were further delineated at the prehearing conferences (PHCs) on February 18, 2003, March 7, 2003, and July 16, 2003. The evidentiary hearings

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[2] 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.

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.[3]

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 (AReM/WPTF), the 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 The Utility Reform Network (TURN).[4]

Implementation of Senate Bill (SB) 1078 and SB 1038 legislation on the 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.

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[3] Before the Commission in a separate application, Application 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 Request for Proposals; a separate schedule to consider this motion was set at the October 31, 2003 PHC.

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

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, 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.

We intend to address all of the issues in the decisionmaking record currently before us in two separate decisions. Today's decision on short-term plans and other time sensitive end-of-the-year issues will be followed by a comprehensive policy decision to be issued as soon as possible after January 1. 2004.

III. Short-Term Plans

A. Overview

The objectives of each utility's procurement process should be (1) to ensure sufficient and reliable energy supply at low and stable rates and (2) to optimize the value of its overall supply portfolio for the benefit of its customers. We recognize that an incentive mechanism is needed to fully align the interests of the utilities and ratepayers. Further direction regarding incentive mechanisms will be forthcoming early in 2004 as part of our upcoming policy decision on long-term procurement planning. Our review of each utility's STPP raises concerns in four areas, and we make modifications to ensure that:

- effective mechanisms for measuring and managing portfolio price risk are in place;
- each utility is given flexibility to sign multi-year contracts with delivery beginning in 2004, but with certain limitations placed on this authority to preclude a utility from locking up all needs for the next five years while the Commission works to implement programs in renewables, energy efficiency, and demand reduction;
- upfront standards are proposed that mitigate the possibility of customers significantly overpaying for procurement products; and
- transparent markets and competitive procurement processes are used unless a strong showing is made that ratepayers benefit from bilaterally negotiated transactions.

In preparing their 2004 plans, the utilities focus on the planning and procurement process that takes place as they move from a twelve month or less position to the actual delivery of electricity to their customers. For this short-term look, the utility's focus is on measuring the price risk exposure of its open portfolio position and managing that position, within a specified consumer risk tolerance level, in a manner that ultimately leads to the procurement and dispatch of power in a least-cost manner. As PG&E's procurement guidelines state: transactions are based on defined customer needs; the utility should not arbitrage in energy markets.[5]

The planning and procurement process is conceptually identical in all timeframes; however, the input assumptions and the granularity of those assumptions become more focused and certain as the operating timeframe approaches real-time.

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[5] August 1, 2003 Energy Resource Recovery Account (ERRA) filing, page 4-2.

The table below seeks to illustrate the process that a utility employs to conduct procurement planning and transaction execution. This table was adapted from PG&E's 2004 ERRA testimony, pages 2-16 and 2-17.

Utility Resource Planning & Dispatch Process

Time Horizon	Input Assumptions	Output and Action
Annual (Conducted on a regular 12-month rolling basis)	Hydro, load, price scenarios (based on forward prices), resource availability.	Forecasted net open position estimate. Formulate strategies for managing open position (identify transaction types and amounts, price thresholds). Assess impact of open position on risk management policy. Make gas supply decisions and volume nominations. Implement procurement strategy and confer with PRG.
Quarterly/ Monthly/Intra-Month	Updates to load, price, and resource availability assumptions.	Forecasted net open position estimate. Formulate strategies for managing open position (identify transaction types and amounts, price thresholds). Schedule plant maintenance. Schedule DWR contracts. Make gas supply decisions and volume nominations. Implement procurement strategy and confer with PRG, if needed.
Weekly Planning	Updates to weekly hydro system operating plan, plant availability, and market prices.	Forecasted net open position estimate. Formulate strategies for managing net open position (identify transaction types and amounts, price thresholds). Schedule DWR contracts. Make gas supply decisions and volume nominations.
Daily Planning	Adjust load forecast, hydro conditions, plant availability, current market prices, transmission constraints, assess activities of ISO operations, pre-scheduling (hourly) of hydro.	Conduct least-cost analysis to determine unit dispatch and market transactions. Strategies for managing open position (identify transaction types and amounts, price thresholds) are conveyed to Day-Ahead traders and Real-Time operators. Re-schedule operations of retained hydro generation to reflect updated conditions. Schedule DWR contracts and other existing contracts. Counterparties are advised per contract terms. Day-Ahead transactions are executed. Market prices are monitored via brokers and electronic exchanges and procurement strategies are revised as needed.
Hour Ahead	Updates to load forecast, hydro conditions, plant availability, market prices. Actual loads are monitored. Retained generation is monitored. Assess activities of ISO operations.	Manage open positions with Hour-Ahead transactions. Monitor market prices. Re-schedule operations of retained hydro generation to reflect updated conditions. Re-schedule DWR contracts to reflect current conditions. Respond to ISO Reliability Must Run calls and further revise schedules of retained generation and DWR contracts as needed.

B. Appropriate Short-Term Reserve Levels and Reliance on Spot Market Purchases

The Joint Recommendation proposes that, for 2004 only, the utilities will provide reliable service by procuring sufficient resources to ensure that they meet their peak demand plus an appropriate operating reserve margin. The level of the operating reserve margin is determined by the Western Electricity Coordinating Council (WECC) and is approximately 7% of peak demand.[6]

The Joint Recommendation proposes that the "operating reserve margin" (ORM): [7]

> Shall be used for purposes of reviewing resource adequacy over a shorter term, such as a year or less and shall be applicable to STPPs. ORM is computed as follows: ORM = (((Dependable Capacity – Reasonably Expected Resource Outages) / Peak Load) – 1) x 100%.

Based on the record developed in this proceeding, we adopt the Joint Recommendation's proposal for 2004 only while the Commission develops its long-term policy on appropriate reserve levels and the types of resources capable of meeting these reserve level obligations.

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[6] 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. "

[7] 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.)

In adopting this level we emphasize the importance that this Commission places on ensuring that the utilities' procurement plans provide reliable service.

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 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 excluding 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.[8]

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[8] 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.

With respect to the utilities' reliance on spot market purchases, in D.02-10-062 the Commission provided the following guidance:

> "While we wish to provide utilities with timing flexibility in meeting their residual net short needs, it is not our intention to have the entire RNS market met in the spot market. Though we do not set an explicit limit on spot market purchases, utilities should plan to minimize their spot market exposure and should justify their planned spot market purchases if they exceed 5% of monthly needs."[9]

We find that this is a reasonable guideline or precept to continue in the utilities' STPPs. We clarify that this guideline applies to energy procurement in Day-Ahead, Hour-Ahead, and Real-Time markets and it is intended to represent a target amount, rather than a hard limit, as there may be economic reasons justifying a utility's decision to exceed the target (i.e., least-cost dispatch). We also find that this guideline provides an appropriate balance between procurement flexibility and reliability.

C. Review of Risk Management and Reporting Proposals

Our discussion here will focus on (1) refinements to risk management and reporting that the Commission directed be given further review in D.02-10-062 and D.02-12-074; and (2) changes the utilities' request in their 2004 short term plans that are substantially different from the existing authority they have under their 2003 plans.

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[9] *Id.* at 32.

1. Portfolio Risk Measurement

In the 2003 short-term plans adopted last year, each utility proposed its own tools and framework to measure portfolio risk. In D.02-12-074 we agreed with ORA's position that the utilities should move in the direction of analyzing portfolio risk based on a probability distribution of risk drivers, but we were not prescriptive at that time in requiring the use of the Value at Risk (VaR) or Cash-Flow-at-Risk (CFAR) models – the models recommended by ORA. We approved, with modifications, the scenario approaches of PG&E and SCE and approved SDG&E's methodological approach without modification. Lastly, we directed Energy Division to schedule a workshop in early 2003 to assist us in gathering additional information on the subject of portfolio risk measurement. Energy Division held the workshop in April 2003 and filed a report on the use of probability distribution models with the Commission on June 6, 2003.

In their 2004 short-term plans, both PG&E and SDG&E propose to use TeVaR (To Expiration Value at Risk), a type of VaR model, to measure and report risk and to trigger review of their hedging plans with the PRG.[10] SCE states it can report portfolio risk using a TeVaR model, but it is in the process of developing a proprietary, in-house model that uses "statistical distribution of portfolio costs….which will show the probability of each particular portfolio cost outcome."[11] At the time of evidentiary hearing, SCE testified that this new model was in a conceptual stage of development. SCE asks that the

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[10] TeVar is not proposed by either utility to make specific trade decisions, a policy that ORA endorses.

[11] TR 8/7, pg 5213

Commission make a finding here to approve the concept and all development costs. On cross-examination, SCE's witness testified that the utility would be willing to have the model validated by an independent source. Model validation will confirm that the criteria of transparency, accuracy, and standardization in risk reporting that the Commission requires are met. SCE indicates that it will share the results of its in-house model with Commission staff and the PRG before using the model.

ORA objects to SCE's request, testifying that if the model is still conceptual at this late stage, it is untimely for approval or consideration in this proceeding. ORA also states that ratepayers should not have to pay for development of this model.

TURN testifies in support of the VaR methodology models and recommends that the utilities' portfolio risk measurement modeling efforts should specifically focus on the concept of "Ratepayer Cost at Risk" (RCaR). According to TURN, RCaR represents the risks that bundled ratepayers face of paying higher rates. Based on its review of the utilities risk measurement proposals, TURN concludes "that the investor-owned utilities (IOUs) are already attempting to implement such a standard."[12]

Public Utilities Code Section 454.5 (b) (1) states that an electrical corporation's proposed procurement plan shall include "an assessment of the price risk associated with the electrical corporation's portfolio." Standardized risk reporting will ensure that the Commission's procurement and risk management policies address the concerns of all ratepayers in an equitable and

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[12] TURN OB, footnote 12, pg 33

unbiased manner, regardless of utility provider. The Commission has a duty to ratepayers to ensure that this price assessment is conducted in a consistent manner, with appropriate standards of transparency inherent in and equivalent to today's commercially available risk management models. Based on the Energy Division's filed workshop report and based on the hearing record, the Commission has a better understanding of the nuances and complexities involved in measuring portfolio risk, as well as the features specific to each utility's energy portfolio. We also note that SCE recently (in November 2003) briefed Commission staff and the PRG on the results of its model development efforts.

We believe that portfolio risk should be reported using TeVaR. The VaR product is a staple of the financial industry. It was developed in the mid-1990's and is widely used by Wall Street as well as by non-financial blue-chip corporations. It was developed to respond to the demands of upper management who wanted a quick and succinct "snapshot" of the worst-case scenario for portfolio loss or exposure. ORA testifies that all of the IOUs' holding companies indicate in their 2002 Annual Reports that they use a VaR model. The commercial viability and acceptance of VaR and other commercially available risk methodologies provides the Commission with confidence that such models yield a consistent and transparent benchmark through which IOU portfolio risk can be measured. As has been noted: "VaR has become a common language for communication about aggregate risk taking, both within an organization and outside (e.g., with analysts, regulators, rating agencies, and shareholders)."[13]

While we continue to believe that it is unwise to be overly prescriptive in directing utility risk management practices, we need to balance our preference for an "even-handed" treatment on procurement policy with an emphasis on transparency and consistency in risk management reporting. We recognize the importance of standardized risk reporting in order to measure ratepayer risk on an "apples-to-apples" basis and to ensure that utility procurement decisions will benefit all IOU ratepayers in an equitable and unbiased manner. Establishing a common benchmark is one way of ensuring that California's ratepayers, regardless of utility, are equally protected from adverse risk, and thereby can reap the benefits of reliable energy at low and stable rates.

Given the timeline of SCE's model development efforts, we adopt here the provisional use of SCE's model pending verification. To initiate the verification effort, SCE shall submit a model report to Energy Division staff, describing the methodology, assumptions, and formulas of the model. When SCE submits this report, it indicates that the model is in final form. Following the submittal of the model report, SCE and Energy Division staff will discuss elements of the validation process, such as selecting the independent auditor, scope of the audit, and the methodology for model validation. An unqualified model certification will serve as the basis for authorizing the model. In the event that the model is not successfully validated, SCE and Energy Division staff will agree on the use of a commercially available risk measurement model.

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[13] RiskMetrics Group; Risk Management: A Practical Guide, p. 3.

Cost recovery for this validated model shall be sought through the General Rate Case (GRC) process, the same as all procurement administration expenses. We authorize PG&E and SDG&E to use the TeVaR methodologies proposed in their short-term plans.

We now address the issue of the level of risk the utilities should report using TeVaR. The 95th percentile, as indicated by SDG&E, accounts for all of the cost possibilities except for the last 5 percent of the high-end tail of the distribution of possibilities. In essence, the 95th percentile presents the 1 in 20 outcome. Costs above this level are expected to occur on fewer than 1 in 20 occasions. Both SDG&E and ORA recommend this level as the standardized reporting measure. SCE states that it can report risk using its proprietary model at any confidence level, but does not advocate a specific level. PG&E recommends reporting at both the 95th and the 99th percentile, with use of the 99th percentile as the standard for managing its portfolio within the Consumer Risk Tolerance (CRT). The 99th percentile presents the 1 in 100 outcome. Costs above the 99th percentile are expected to occur less than once in a hundred occasions.

We believe risk reporting should serve as a "roadmap," alerting the Commission of the relative risk in different time periods. At a 95th percentile, we would be aware of the costs associated with a 1 in 20 possibility, but not the more remote or extreme possible outcomes. In D.02-12-074, we directed the utilities to consult with their PRGs when measured portfolio risk exceeds 125% of the adopted CRT. Based on this protocol, IOUs called a PRG meeting on two occasions to discuss the risk drivers accounting for the upward swing in portfolio risk (SDG&E on February 25, 2003 and PG&E on March 5, 2003).

We find that a 99th percentile reporting will provide additional price volatility information and should not be burdensome to the IOUs or to the PRGs. We are guided by TURN's testimony that our risk management standards should seek to protect bundled ratepayers against highly unlikely events. While we do not adopt PG&E's additional stress scenario proposal (as a complement to TeVaR measurement) as a requirement, there may be instances, e.g., the gas price run-up earlier this year, where this type of analysis is prudent and we encourage each utility to perform any additional scenario analysis it believes is warranted and to discuss this information with its PRG. With respect to portfolio risk notification, we adopt PG&E's proposal for use by each IOU, endorsed by ORA, with modifications:

1. If between quarterly PRG consultations, a utility's estimated portfolio risk (measured at the 99th percentile) exceeds 125% of the CRT, the utility will promptly meet and confer with its PRG to discuss the underlying risk drivers and factors affecting the change in portfolio risk and to decide whether specific hedging strategies and/or plan modifications are needed to reduce portfolio risk to within the CRT threshold.
2. If the utility and the PRG decide that plan modifications are needed, the utility will file these modifications in the form of an expedited application, within 15 days of the PRG meeting.
3. Until the application is approved, the utility may operate under its existing plan.

Therefore, we adopt risk reporting using a by-product of VaR (TeVaR), measured on a 12-month rolling basis, at a 99 percent confidence level. We order the utilities to file a monthly portfolio risk report with the Commission's Energy Division. Beginning in 2004, the monthly reports should reflect an estimate of portfolio risk for each month on a rolling 12 month basis, on a quarterly basis for months 13-24, and on an annual basis for months 25-60.

2. Risk Management

In Assembly Bill (AB) 57, Section 1(d), the Legislature:

> "Directs the Public Utilities Commission to assure that each electrical corporation optimizes the value of its overall supply portfolio, including Department of Water Resources contracts and procurement pursuant to Section 454.5 of the Public Utilities Code, for the benefit of its bundled service customers."

In implementing Pub. Util. Code § 454.5, the Commission is required to (1) assess the price risk associated with each utility's portfolio; (2) ensure the utility has moderated its price risk; and (3) ensure the adopted procurement plan provides for just and reasonable rates, with an appropriate balancing of price stability and price level. (Sections 454.5(b)(1), 454.5(d)(4), and 454.5(d)(5).)

The manner in which each utility identifies and manages price risk, and optimizes the value of its overall supply portfolio for the benefit of its bundled service customers is the risk management function. The Commission has three primary oversight responsibilities in its short-term risk management policy: (1) specify the interim level of consumer risk tolerance that the utilities should use in managing their short-term procurement portfolios; (2) make sure each IOU has accurate and transparent tools in place to measure ratepayer risk exposure; and (3) review and adopt utility procurement plans. We address here consumer risk tolerance.

(a) Consumer Risk Tolerance (CRT)

In D.02-10-062, we defined CRT as "the price that an average consumer would be willing to pay to reduce the risk of higher prices in the future" (i.e., the cost-to-risk tradeoff), discussed its importance in setting the limits of potential price risk under which each utility should manage its procurement portfolio, directed the Energy Division to retain a consultant to gather additional information regarding appropriate CRT levels, and requested parties to propose an interim CRT.

In D.02-12-074, we adopted an interim CRT level and notification protocol based on modifications to proposals advanced by ORA and TURN. While PG&E and SDG&E filed CRT proposals in their modified 2003 plans, SCE did not. SCE's interpretation of the CRT protocol that was outlined in Confidential Appendix C to D.02-12-074 led it to later file a petition to modify D.02-12-074, which we addressed in D.03-06-076.[14]

At present, each utility implements the CRT slightly differently. PG&E is the only utility to publicly discuss the specifics:

> "PG&E currently manages the electric portfolio recognizing a consumer risk tolerance of one-cent per kWh, assumed to apply to a potential rate increase of one-cent per kWh over a one-year period. This translates to a risk tolerance level of about (confidential number). PG&E's approved 2003 Procurement Plan also established a notification limit to the Commission when portfolio exposure reached 125 percent of this risk tolerance." (Exhibit 26, p. 3-2.)

As a result of budget uncertainties, the consultant study authorized under Section 454.5(f) has been delayed. Energy Division plans to consult with each utility in the first quarter of 2004 and then prepare a draft scope of work for comment by all parties. A final consultant's report should be served on all parties for comment and the consultant made available as a witness if requested by the Commission.

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[14] In hearing testimony, witness Cini indicated that, as per D.03-06-067, SCE no longer sees the CRT as a barrier to forward procurement, and that its 2004 STPP should be modified to reflect this position.

For 2004, the utilities should continue to use the interim CRT adopted in D.02-12-074 as well as the risk notification protocol described in Section III.C.1. of the decision.

D. Authorized Contract Term Duration and Volume Limits

The PG&E and SDG&E short-term plans focus on implementing the first-year (2004) of their respective long-term plans whereas SCE's short-term plan covers the period 2004-2008. With respect to contract term authorization, PG&E proposes to transact for contracts of up to one-year in term due to its bankruptcy status. We address PG&E's credit concerns as they relate to procurement in Section III.F. SDG&E and SCE do not propose contract term authority beyond the five-year term duration we authorized in D.02-10-062 for the 2003 short-term plans.[15] We agree that utilities should not limit their procurement exclusively to contracts with terms of one year or less. Therefore, as part of our approval of short-term plans, we authorize the utilities to enter into contracts with terms up to five years for transactions to meet 2004 needs with delivery beginning in 2004.[16] Though SCE presented a five-year procurement plan extending to 2008, we do not authorize forward contracting for products with delivery scheduled to begin after 2004. We also emphasize that in continuing the five-year contracting authority granted in D.02-10-062, it

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[15] D.02-10-062, at page 46, states: "The short-term procurement plans should cover only plans for activities to procure electricity in 2003 (though the actual power bought or contracted for in 2003 may cover needs for up to five years)."

[16] For example, if a utility identifies a need of 50 MW in 2004, growing to 60 in 2005 and to ever-larger amounts in subsequent years, the utility is authorized to contract 50 MW to be delivered in 2004, continuing at the 50 MW rate up to five years.

is our strong expectation that the utilities shall not lock-in resources that would preclude Commission action in the long-term phase of this proceeding for the preferred resources identified in the "loading order" of the Energy Action Plan (EAP).

With respect to the identified need for physical products, based on our review of the utilities' short-term plans and parties' comments on these plans, we find the volumetric limits/position targets submitted by PG&E, SCE SDG&E to be reasonable.

E. Upfront Standards for Utility Procurement Products and Transactions

In D.02-10-062, Section VI, the Commission adopted a list of authorized products, specified authorized procurement transaction processes, and established upfront reasonableness guidelines for transactions. Parties propose various modifications in these areas.

1. Authorized Products

In D.02-12-062, we authorized the utilities to conduct procurement using a wide range of products and instructed the utilities to specify in their 2003 procurement plans the products they intend to use along with a definition of the product and the associated benefit/cost attributes. The specific procurement products that we authorized in D.02-12-062 are shown below. We continue to authorize the utilities to procure these products.

Authorized Procurement Products		
Transaction	**Description**	**Benefit /Cost**
Forward Spot (Day-Ahead & Hour-ahead (purchase, sale, or exchange)	Purchase pre-scheduled energy or load reductions at fixed price	Needed to balance short-term load/resource changes/ Vulnerable to price volatility
Real-time (purchase or sale)	Energy imbalance transactions or load reductions	Balances Short-term needs/ Vulnerable to price volatility
Forward Energy (purchase or sale)	Contracts entered into in advance of delivery time, includes block/forward products (e.g., fixed amounts of energy over a specified period of time (e.g., 7x24, 6x16, super-peak, and shaped products) Could be fixed price	Reduces price risk / Risk that prices will be below contracted rate
Forward Energy (demand side)	Baseload usage reduction through investments in permanent energy efficiency	Reduces price risk and cost overall
Capacity (purchase or sale)	Right to purchase energy in exchange for capacity payment. If exercised, buyer also pays incremental energy charge at specified rate	Reduces spot price risk / Reduced risk comes at cost of reservation and energy charges
Capacity (demand side)	Right to purchase load reductions for capacity payments	Provides dispatchable reliability
On-site energy or capacity	Energy or capacity products self-generated on the customer side of the meter	Provides locational reliability and lowers price risk through supply diversity
Tolling Agreement	Type of capacity product where buyer hedges fuel cost risk by providing the gas supply, transportation, and storage	Reduces peak price risk / Buyer pays reservation or capacity charges, and is open to gas price risk
Peak for off-peak exchange	Trades peak energy for off -peak energy (x peak MWh < y off-peak MWh)	Reduces peak price risks / Increases off-peak price risks
Seasonal exchange	Buyer receives peak energy in Summer and returns peak energy in Winter	Reduces summer price risk /Increases winter peak price risk

Authorized Procurement Products		
Transaction	**Description**	**Benefit /Cost**
Physical call (or put) option	Deal to purchase energy in future at pre-set price (price may be pegged to an index). [Call is right to purchase, put is right to sell.]	Call reduces price risk, with option to not exercise right if prices lower. Put insulates from reduced value of excess energy / Fee associated with these rights
Financial call (or put) option	Caps energy price without losing the benefit of lower prices. Price of energy is capped at a fixed price; at times when an agreed upon index price falls below the fixed (strike) price, the buyer pays the lower index price	Reduces price risk / Reduced risk comes at price of option premium (fee)
Financial swap	Buyer gets or pays difference between floating price index and a fixed negotiated price	Locks in fixed price (reduces price risk) / Cost if negative difference between floating index and fixed price
Insurance (Counterparty credit insurance, cross commodity hedges)	Buyer can insure against various adverse events (such as extreme temperature, a generating unit failure, or counterparty default, among others), to reduce price risk	Insurance policies can reduce price risk, but increase energy costs by the amount of the insurance premium
Electricity Transmission Products	Arranged through CA ISO and with non-CAISO transmission owners. Also includes purchase of transmission rights or use of locational spreads.	Reduces price risk associated with varying transmission conditions.
Gas Transportation Transaction	Buyer contracts for transportation of gas to a determined delivery point, at a set price (could be fixed or variable) over a specified time-frame	Reduces price risk associated with gas transportation (and therefore, limits some electric generation price risk for gas-fired units)
Gas Storage	Buyer reserves gas storage capacity for a defined price	Hedges price risk associated with gas storage
Gas Purchases	Purchased on a monthly, multi-month, or annual block basis	Used to hedge fuel cost risk associated with capacity contracts

Authorized Procurement Products		
Transaction	**Description**	**Benefit /Cost**
Ancillary Services	Replacement reserve, regulation up, regulation down, spinning-reserve, non-spinning reserve	Needed to assure system reliability

In its 2004 procurement plan, PG&E identifies a confidential subset of these authorized products that it is likely to use. SCE notes that in addition to the products listed in D.02-10-062, it seeks authority to transact for the following additional products.

Transaction	Description	Benefit / Cost
Structure Transactions	Combine one or more product types, varying expiration dates, tiered prices, etc.	Tailor hedges to match your exposure.
Emissions Credits futures or forwards	Provides right to purchase emissions credits at a fixed price	Hedge exposure to emissions limits resulting from contractual terms.
Weather triggered option	Any transaction otherwise authorized with payment / exercise rights based on weather.	Tailor hedges to match exposure correlated with weather conditions.
Forecast Insurance	Payment to SCE occurs in case of deviations of weather from forecast	Hedges costs resulting from inaccurate forecasts
Gas Purchases	Purchased on a daily basis	Used to hedge fuel cost risk associated with capacity contracts.

We find that these types of transactions are reasonable for SCE’s 2004 procurement.

SDG&E’s 2004 procurement plan states that last year’s table of authorized procurement products includes substantially all of the physical products SDG&E

intends to use in its short-term procurement activities. SDG&E explains in detail the types of transactions it wishes to engage in during 2004. In addition to the products that are included on the list from D.02-10-062, are the following:

Transaction	Description	Benefit / Cost
Non-FTR Locational Swaps	SDG&E will have available to it certain resources located outside of the SDG&E service territory that do not have FTR protection. SDG&E may choose not to import the power into SP15 but sell it at the delivery point, purchasing replacement power in SP15 or another location with less congestion risk.	There is some risk of congestion from distant resources without FTR protection. This strategy mitigates that risk. Such open positions would be measured and managed consistent with overall risk management practices.
FTR Locational Swaps	SDG&E owns some FTRs from ZP26 to SP15 via the CAISO2003 FTR auction. When some or all of the FTR capacity is not being used for Sunrise energy deliveries, SDG&E will enter into locational swaps to improve on the initial value of the FTR hedge.	This allows SDG&E to take advantage of the value of its FTRs and reduce overall costs.
Counterparty Sleeves	Two-sided trades where the same product is purchased from one counterparty and sold to another simultaneously.	This helps SDG&E reduce its credit exposure with overexposed parties. It may also reduce SDG&E's costs where it facilitates trades between parties that cannot trade with each other due to credit restrictions.

We find that these types of transactions, though not explicitly accounted for in the list of authorized procurement products included in D.02-10-062, are reasonable for SDG&E's 2004 procurement.

2. Transactional Processes

In D.02-10-062, the Commission authorized the utilities to procure products using the transaction processes listed below.

Transaction Process	Guidelines
Competitive Solicitations (Requests for Offers)	D.02-10-062 set forth guidelines governing the process by which the IOUs shall conduct RFOs. These guidelines are as follows: • Procurement plans shall specify the steps of the solicitation process to be used. The process shall be consistent with the competitive solicitations in use now under transitional procurement authority. • Competitive solicitations may be all-source or may be segmented to allow similar sources to compete with each other, but must cover all of the sources described in section V above. • Solicitations should be widely distributed (starting with bidders list used under transitional procurement authority). Required items shall include among other things: Description of product requirements Term Minimum and maximum bid quantities Scheduling and delivery attributes Credit requirements Pricing attributes • Each utility shall update its procurement plans to specify and describe the evaluation tools and methodology it will use to rank and select bids, such as: Minimum requirements for counter-party creditworthiness Minimum number of bids that must be received An evaluation of cost-to-risk tradeoff (consumer risk tolerance level) of the various bids
Transparent exchanges, such as Bloomberg and Intercontinental Exchange.	• Approved utility plans will identify and describe the various electronic energy trading exchanges that each utility proposes to use (e.g., Bloomberg, Trade Spark, Intercontinental Exchange). • The procurement plans shall demonstrate that the identified electronic trading exchanges the utility intends to use provide transparent prices.
ISO markets: Imbalance Energy, Hour Ahead, and Day Ahead (when operational)	• ISO spot market transactions are authorized to balance system and meet short-term needs. • Procurement plans shall describe procurement strategies for hedging the utility's overall portfolio risk with ISO spot purchases. • While we wish to provide utilities with timing flexibility in meeting their residual net short needs, it is not our intention to have the entire RNS met in the spot market. Though we do not set an explicit limit on spot market purchases, utilities should plan to minimize their spot market exposure and should justify their planned spot market purchases if they exceed 5% of monthly needs.

	•We authorize the use of a Day-Ahead Market should it become operational.
Inter-Utility Exchanges	In. D.02-10-062 the Commission provided the following guidance: • Unless we adopt specific guidelines for negotiated IUEs these deals would only occur through an RFO process, which is unlikely to be as successful in price or in meeting specific needs of both parties. By adopting the benchmark and other guidance discussed below we allow negotiated IUEs to be included for approval in the monthly advice letter filings. • The important elements to justify an IUE as reasonable would include: Cost-effective reductions to seasonal or specific RNS, Cost effective reductions to seasonal or specific Residual net-long positions. To justify as cost-effective an IUE to reduce RNS (acting as a buyer), the utility will have to demonstrate that at the time of executing the IUE agreement the expected costs for the repayment was less than the avoided incremental costs at the time of delivery. This determination would be based upon the incremental costs of the existing delivery time and repayment time portfolios available when the IUE is negotiated. For example, if the delivery's existing portfolio incremental transaction cost or the most recent RFO bids for the delivery period are more than $100 and if the repayment portfolio's incremental transaction cost was $100 or less then the IUE could be deemed reasonable when filed by advice letter. This total transaction cost would account for the differing values of capacity, energy, ancillary services, and volume of energy in the two sides of the transaction. To justify as cost effective an IUE to reduce residual net long positions (as a seller being repaid in capacity, energy, or ancillary services) the utility would have to demonstrate that the average portfolio value of the time of repayment is higher than the forecast of spot prices when firm energy would otherwise be dumped as surplus into the spot market. (D.02-10-062 ,)
Direct bilateral contracting with counterparties for short-term (i.e., less than 90 days) products	D.02-10-062 authorized such contracting subject to a "strong showing" that these transactions represent a reasonable approximation of what a transparent competitive market would produce. D.02-12-074 added that the strong showing can be met by a "comparison to Requests for Offers completed within a month of the transaction." In D.03-06-067, the Commission waived the "strong showing" standard for negotiated bilaterals for non-standard products procured 31 days or less in advance of delivery and with terms of one-calendar month or less. "Although we waive the strong showing standard for these transactions, the utilities should demonstrate that such transactions are reasonable based on available and relevant market data supporting the transaction. This may include, showing competing price offers, result of market surveys, broker and online quotes, and/or other source of price information such as published indices, historical price information for similar time blocks, and comparison to RFOs completed within one month of the transaction. Additionally, we stated that in instances when a utility knows that it will have a need for non-standard products on a forward and recurring basis, "we strongly encourage the utilities to transact for such products using an RFO process."
Utility Ownership	Utilities may propose to buy or construct generation

The utilities propose to conduct procurement using the same transactional processes listed above in their 2004 procurement plans. SCE's short-term plan also notes that it plans to use (i) Open Access Same-Time Information Systems (OASIS) to procure standard electric transmission products from transmission providers throughout the WECC region at FERC tariffed rates and (ii) voice and on-line brokers, as it did in its approved 2003 procurement plan. SDG&E and PG&E propose to use brokers as well. SDG&E's plan speaks to the use of over-the-counter brokers stating:

> "SDG&E includes over-the counter brokers. . .in the definition of exchanges because these firms offer a common mechanism of matching buyers and sellers at the current competitive market price, in concert with electronic exchanges… In addition, there is a high degree of overlap of products and prices offered since counter parties can use electronic exchanges and over-the-counter brokers interchangeably, thus increasing transparency and providing an opportunity for price comparisons." (SDG&E 2004 Short-Term Plan, p. 22.)

We recognize that there may be a pro-competitive effect from broadening our understanding of transparent exchanges to include reputable OTC brokers. We will hold the utilities to the same high standards for transactions consummated through OTC brokers as we do for exchange transactions. That is, the utilities shall demonstrate that the identified OTC brokers provide prices that are equivalent to those of exchanges.

PG&E proposes to expand the use of bilateral contracting to include products with delivery starting up to six months out. This differs from the authorization we provided in D.02-10-062 where we restricted direct bilateral contracting to short-term products only (i.e., less than 90 days). PG&E does not specify a term length restriction for the expanded bilateral contracting authority it seeks in its 2004 procurement plan.

In explaining the use of bilateral contracts in procurement, PG&E explains that such contracting occurs through private negotiation, through electronic exchanges, and through brokers. PG&E explains that bilateral contracting is preferred over competitive solicitations for a number of reasons, including: (1) use of competitive bid processes limits PG&E's price discovery; (2) the competitive bid process has potentially high transaction costs for both buyers and sellers and this can limit the number of parties participating in an RFO process; (3) RFOs may require bidders to hold prices open for an extended period of time while the process unfolds, thereby increasing prices; (4) competitive solicitations typically take several months to complete; (5) limiting transactions to only competitive solicitations can lead to market power because bidders will know the utility has limited alternatives to execute transactions; (6) utilities outside of California are the most likely counterparties for inter-utility exchanges; and (7) the financial duress besetting many counterparties in the WECC region may limit the role of marketers. Finally, PG&E states:

> "If all products greater than three months' duration, or to be delivered three months out, were transacted via a competitive bid process, PG&E would be frequently issuing RFO/RFP up to two months before actual delivery, a costly and impractical proposition. Hence, PG&E necessarily relies more frequently on bilateral contracting for products with delivery starting up to six months out." (2004 short-term plan, PG&E, p.4A-3, 4.)

SCE seeks to expand the use of bilateral contracting as well, specifically for negotiated bilaterals as opposed to brokers and exchanges. For negotiated bilaterals, SCE requests authority to transact for products up to five years in term. SCE conditions this expansion of bilateral authority in instances where "five counterparties or fewer can supply the service or enter into a particular transaction (this may occur, for instance, when purchasing natural gas storage or pipeline capacity). SCE also proposes that physical gas bilateral transactions be authorized for up to [five years] if the pricing for such a transaction is index linked." (SCE 2004 Short-term plan, p. 128.)

SDG&E likewise proposes to use negotiated bilaterals, particularly for non-standard products, but does not specify a term length restriction.

With the exception of ORA objecting to SCE incorporating a five-year horizon under its 2004 short-term plan, no party voiced opposition to these bilateral contracting proposals. We discuss this request for authority in relation to the cost-effectiveness testing for transactions and benchmarks proposed for each type of transaction, as discussed below.

3. Affiliate Transactions

In last year's hearings, 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.[17] (D.02-10-062, page 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 of D.02-10-062 and D.02-12-074, PG&E and Sempra Energy (Sempra) challenged the moratorium on affiliate transactions, and SDG&E and Sempra challenged 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.

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

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 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."

In this proceeding parties have provided testimony and briefs on the merits of the existing moratorium, as well as potential changes, including the issue of utility ownership of new generation; the merits of having different affiliate rules for short-term and long-term transactions; and whether certain of PG&E's and SDG&E's dealings with other departments within their companies and with affiliates merit specific attention by this Commission.

Today's decision does not explicitly address this testimony and briefing, but reserves the issue of modifications to the existing affiliate ban to the upcoming policy decision. Until that decision issues, the parties must abide by the status quo, and conform their conduct to the requirements of D.02-10-062 and D.03-06-076.

4. Cost-Effectiveness Testing for Transactions & Benchmarks

ORA, PG&E and SCE each propose modifications to the transaction selection protocols adopted in the 2003 STPPs.

(a) ORA's Proposal

In its June 23, 2003 direct testimony, ORA requests that the Commission approve a procurement process for use by PG&E, SCE, and SDG&E. The process, as proposed by ORA, is as follows:

1. Define scenarios or model inputs;
2. Weight scenarios or model inputs;
3. Establish other input assumptions;
4. Establish candidate products that would be effective given particular stress scenarios or other model results;
5. Solicit hedge products;
6. Share bids with PRG;
7. Evaluate candidate hedges and rank according to cost-benefit analysis;
8. Meet with the PRG and solicit comments from PRG members and attempt to reach a consensus;
9. Tentatively select hedges;
10. Update TeVaR to reflect the addition of the new candidate hedges; and
11. Select hedges.

The 11-step process outlined above is consistent with the procurement process proposed by PG&E in its 2004 procurement plan with the exception that ORA has inserted several steps for utility consultation with its PRG. We also note that ORA's 11-step procurement process generally reflects the procurement process that each utility employed in 2003 for competitive solicitations.

The issue of how often this process should be used by the utilities was raised by SCE during hearing when it pointed out that the utility typically enters into between 20,000 and 50,000 transactions a year. SCE implied that the process would be too cumbersome and unwieldy for all procurement transactions given the large volume of transactions the utility conducts per year. ORA clarified on cross-examination that it does not advocate use of its proposed process for spot-market transactions, one-week-ahead transactions, and prompt-month transactions (transactions executed one calendar month prior to the month of delivery).

(b) PG&E's Proposal

PG&E proposes price benchmarks for the various procurement products it seeks to transact for under its 2004 short-term plan. For transactions of real-time energy and ancillary service from ISO markets, PG&E proposes that ISO settlement prices should serve as the benchmark given that ISO markets are the only markets for such products. For standard procurement products, PG&E essentially proposes to use "available and relevant market data, including price quotes from counterparties, brokers, and electronic exchanges, forward curves developed by PG&E and/or third parties, and published indices, supplemented by online price information from news services like Bloomberg and Reuters."[18] For non-standard spot market transactions in the day-ahead and hour-ahead markets, when there is no relevant market information, PG&E proposes to demonstrate that these transactions are reasonable based on the need for the products and to document how these non-standard products "were evaluated and adjusted in value compared to more visible price benchmarks."[19]

PG&E further states that in situations where no relevant market data exists to establish a benchmark, PG&E will seek the concurrence of its PRG to go

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[18] PG&E Short-Term Plan, p. 4A-4

[19] Ibid

forward with the transaction based on a benefit/cost test pre-agreed with the PRG.

ORA does not challenge PG&E's proposed benchmarks for real-time energy and ancillary services procured from ISO markets. With respect to other product benchmarks ORA recommends that the Commission reject these benchmarks finding that they are incomplete, oversimplified, and lacking definition. Additionally, as discussed in more detail in the previous section addressing ORA's proposed 11-step procurement process, ORA objects to PG&E's proposal to use a pre-approved benefit/cost transaction test.

We note that although PG&E did not advance specific benchmarks in its procurement testimony, in its 2004 Energy Resource Recovery Account testimony, filed August 1, 2003, PG&E presents numerous specific benchmarks for electricity products. We summarize those benchmarks below by transaction term.

> **Term Transaction**
>
> Forward: Prompt-month or longer
> Term: 21 days or longer.
>
> Index: Calculated by averaging end of trading day forward prices for the appropriate product (on-peak or off-peak), location (COB, NP15, SP15), time frame (month or quarter), and transaction date of Brokers (Amerex, Natsource, ICE, Prebon and TFS).
>
> **Balance of Month Transaction**
>
> Forward: Current month or next month
> Term: less than 21 days, $\geq$ 14 days
>
> Index: Calculated by averaging the end of trading day forward prices for the appropriate product (on-peak or off-peak or flat), location (COB, NP15, SP15), month, and transaction date of Brokers.

<u>Day Ahead Transaction</u>

Forward: Transactions for the next one, two or three days (according to ISO scheduling protocols)
Term: One day

Index: Calculated by averaging the index for the appropriate product (on-peak or off-peak or flat), location (COB, NP15, SP15), month, and transaction date of Brokers.

<u>Hour Ahead Transaction</u>

Forward: HA Market, current month or next month forward
Term: less than 24 hours.

Index: Developed using Dow Jones Hour Ahead indices, which are currently the only publicly available HA indices. The HA indices for some hours at COB and SP15, and all hours at NP15 were estimated, as there is no published NP15 HA index and hourly price data for COB and SP15 are spotty. For **<u>COB</u>**: the COB HA index was used when available; when there was not a Dow Jones published index for COB for a given day, the hourly Dow Jones MidC index was used with an adder based on the DA COB/MidC spread. For **<u>NP15</u>**: when a COB hourly index was available it was used with an adder based on the NP15/COB DA spread (on-peak or off-peak hours as appropriate). If a COB index was not available, the SP15 hourly index was used when available with an adder based on NP15/SP15 spread (on-peak or off-peak hours as appropriate). If neither the COB nor the SP15 hourly index was available, the MidC hourly index was used with the DA on-peak or off-peak NP15/MidC spread. For **<u>SP15</u>**: the SP15 HA index was used when available, when there was not a Dow Jones published index for SP15 for a given day, the hourly Dow Jones Palo Verde (PV) index was used with an adder based on the DA SP15/PV spread. If neither the SP15 nor the PV index was available, the calculated NP15 hourly index was used with the DA on-peak or off-peak SP15/NP15 spread.

(c) SCE's Proposal

SCE's adopted 2003 STPP provided a complex screening system for long-term and non-standard products. However, for standard products and short-term transactions, the STPP provided a less complex methodology. In its proposed 2004 STPP, SCE presents a similar set of tools and methodologies to evaluate non-standard products for its portfolio, and again states that the method for evaluating standard products and short-term products should be simpler. SCE proposes no volume or transaction rate limits for short-term transactions, which it defines as electrical energy or gas transactions, including transactions for the transmission or transportation of the commodity, entered into within 31 days of delivery for a term that does not exceed one calendar month. SCE also proposed forward transaction limits and price benchmarks for transactions. SCE states that its choice of products and methods of transactions are consistent with the adopted plan for 2003 and are reasonable.

(d) SDG&E's Proposal

SDG&E's 2004 plan asserts that its proposed trading methods meet the criteria for reasonableness. Regarding its proposed use of bilateral contracts, the Company asserts:

> "Prior to executing such an [sic] structured transaction, SDG&E would (1) compare the economic and operational benefits to its associated premium over dispatching a CDWR contract and against purchasing a standard energy product valued against the forward prices covering the same period of delivery, and (2) demonstrate that the product benefits the overall portfolio by reducing net cost or customer VaR. This meets the criteria for bilateral contracts set forth

> in Section VI.E., of D.02-10-062 and these transactions should therefore be deemed reasonable."[20]

SDG&E also asserts in its 2004 plan that all transactions entered into through use of transparent exchanges and brokers should be deemed reasonable, as should its proposed use of spot markets, competitive solicitations, and purchases of reserves and other ancillary services, all of which will be completed in a manner meeting the criteria established in D.02-10-062.

5. Discussion

For the 2004 short-term plans, we authorize the utilities to conduct procurement using the following transactional methods:

1. Competitive Solicitations (RFOs/RFPs)
2. Electronic exchanges and voice and online-brokers
3. ISO Markets
4. Inter-utility Exchanges
5. Negotiated Bilateral Contracting as defined and limited below; and
6. OASIS sites

Although we agree with ORA that their recommended 11-step procurement process represents a prudent and common-sense approach, we do not explicitly require the utilities to follow the process. For short-term transactions, the process is clearly too burdensome. For longer-term transactions beyond 90 days, such as long-term Power Purchase Agreements, acquisition of generating resources, or other significant contracting efforts involving competitive solicitations (i.e., Requests for Offers), we would prefer that the

[20] SDG&E ST Plan, page 21

utilities follow a process similar to the one suggested by ORA, but will not explicitly require use of the 11-step process precisely. We do require that the utilities consult with their PRGs for transactions greater than 90 days, but leave to the utilities' discretion the exact process for approaching such procurement. During our review of such transaction, we will, however, look favorably on utilities' demonstration that their procurement practices have followed a process substantially similar to that suggested by ORA.

Whereas SCE and SDG&E identified in their proposed short-term plans the brokerages and exchanges those firms propose to rely on, PG&E did not. PG&E should provide such a list in a compliance advice letter filing updating its short-term plan.

In D.02-10-062, we restricted the use of "direct bilateral contracting." Our purpose in limiting the use of such contracting was to (i) prevent a situation from arising where utilities would conduct substantial levels of procurement through private negotiated deal-making as opposed to through processes involving greater price transparency and competition while at the same time (ii) providing the utilities with transaction flexibility to procure near-term and short-term products (including non-standard products) necessary for system balancing and reliability purposes without burdening the utility with a competitive bid process. In limiting the use of negotiated bilaterals, we also sought to promote procurement transaction transparency given the restriction in Pub. Util. Code § 454.5(d)(2) on ex-post reasonableness reviews of a utility's procurement activities and given the Legislative intent of AB 57 for the Commission to approve procurement plans that employ the use of competitive procurement processes.

PG&E articulates a number of significant points regarding the use of negotiated bilaterals, but other than stating that such contracting would be conducted for products with delivery up to six months out, it does not propose any restrictions or parameters delineating how much of its procurement would be secured through negotiated deal-making. If we adopted PG&E's request, would a utility seek to conduct most or nearly all of its procurement up to six months out through a series of negotiated bilateral agreements? This remains our concern. Pending the development and adoption of a procurement incentive mechanism, we authorize the utilities to pursue negotiated bilaterals subject to the restrictions outlined above. We stop short of adopting PG&E's proposal until a showing is substantiated that such bilateral contracting will not become the default transactional process for all products with delivery up to six months out.

Negotiated bilateral contracting is not amenable to the 11-step process, and therefore we do not mandate it for negotiated bilateral contracts. We grant authority for the use of negotiated bilateral contracting in three limited circumstances. First, for short-term transactions of less than 90 days duration and less than 90 days forward, the IOUs are authorized to continue to use negotiated bilaterals subject to the strong showing standard we adopted in D.02-10-062, as modified by D.03-06-067. Any such negotiated bilateral transactions shall be separately reported in the utilities quarterly compliance filings.

Second, utilities may use negotiated bilateral contracts to purchase longer term non-standard products provided they include a statement in quarterly compliance filings to justify the need for a non-standard product in each case. The justification must state why a standard product that could have been purchased through a more open and transparent process was not in the best interest of ratepayers.

Last, we expand the authorization for use of negotiated bilaterals for standard products in instances where there are five or fewer counterparties who can supply the product, as suggested by SCE. We limit this authority, however, only to the two categories of gas products cited by SCE: gas storage and pipeline capacity. In such instances, the utility needs to affirm that five or fewer counterparties in the relevant market offered the needed product. Any resulting contract shall be separately reported in the utilities' quarterly compliance filings

F. Cost of Collateral

In their procurement plans filed with the Commission on May 15, 2003, PG&E and SCE stated that their ability to secure reasonably priced financing for short-term procurement was hindered because of (1) SCE's non-investment-grade rating and (2) PG&E's bankruptcy status. Given their current financial condition, each argued that the procurement options available to them may be limited and costly. The Commission now notes that while PG&E is still operating under the terms of its Reorganization Plan, SCE has recently regained an investment-grade rating from S&P, Moody's and Fitch.

SCE asks that the Commission take steps to improve and 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 Commission's policy for assessing the utilities' financial capabilities should consider issues which affect capital structure in tandem with those affecting immediate cash needs. This will ensure that these costs are treated in an appropriate and coherent manner. Moreover, we note that there are elements of credit risk related to collateral issues which transcend cash requirements. The cost of capital proceeding addresses issues relating to capital structure and risk. In the forthcoming decision on long-term procurement, the Commission will focus on long-term financial issues, such as debt equivalency, and will at that time decide the appropriate forum for recovery of collateral costs.

PG&E states that its procurement-related credit capacity is presently capped by a dollar limit as per the terms of its Reorganization Plan. Given these limitations, it expects its short-term procurement options may be compromised, particularly as it is still in bankruptcy.

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."

First, the Commission reminds the IOUs that the inherent responsibilities in managing and procuring for a integrated DWR/URG portfolio, subject to the requirements of least-cost dispatch, means that portfolio segregation is not possible. Second, we refer PG&E to Article 14.4 of its Servicing Order, that address conditions for force majeure. Specifically, we refer to language which states "Any Insolvency Event shall not constitute force majeure." We do not grant PG&E's request for relief.

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. As a procedural matter, we find that the appropriate forum for issues relating to capital structure is the Cost of Capital proceeding. We refer such issues to that proceeding.

It is essential to balance the cost of collateral against the risk of counterparty default. PG&E currently has a non-investment credit rating, and with it, limited sources from which they can secure collateral financing. One possible solution is to rely more on transacting with similar non-investment grade counterparties, without collateral support. However, 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.

The Commission recognizes the dearth of financially stable and viable trading counterparties in the market, as well credit contraction in the industry, and the implications of these conditions on each utility's credit policy. If the Commission does not establish credit standards here and the utilities; counterparties default on their contractual obligations, ratepayers may be harmed.

We now set in place credit guidelines to support 2004 transactions. 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.

G. Fuel and Power Forecasts

ORA and TURN both note that SCE and SDG&E gas price forecasts did not include near term gas prices, and this factor may affect the accuracy of the conclusions. ORA recommends that the utilities should use consistent fuel price forecasts in both short-term and long-term resource planning. ORA also recommends that near term gas prices should always be incorporated or used to supplement testimony in future procurement planning proceedings. TURN argues that the IOUs' fuel and price forecasts are already outdated, jeopardizing the value of the analyses contained in their resource plans. TURN adds that actual gas and electric market prices reported for June 2003 were approximately equal to the "90 percent high" levels of the IOU probability distributions for future Junes starting in 2007.

1. Discussion

While it is our expectation that the IOUs use the best available data in preparing analyses, it is an eternal truth that forecasts are quickly outdated. We cannot fault the utilities for relying on forecasts that did not anticipate this spring's run up in gas prices. And we note that since the spring, prices have declined. If anything, the facts that TURN and ORA present support a different conclusion: it may be that gas price forecasts upon which the utilities depend underestimate the degree of price volatility in gas markets. Perhaps the distribution of future gas prices is wider than anticipated by current forecasters. Though the forecasters may have the long-term trends right, the amount of price variability around those trends may be greater than has been thought up to now.

For future filings, we expect the utilities to use their best effort to obtain up-to-date forecasts, and also to estimate appropriately the high and low cases surrounding those forecasts. Additionally, we note that as part of its 2004 procurement plan, PG&E proposes to update its plan on a quarterly basis to reflect changes to its open position and to relevant market prices. We find that it is appropriate for each of the utilities to review market conditions relative to fuel forecasts on a quarterly basis with its PRG and to file plan updates if the plan does not adequately capture current market conditions.

Finally, we note that given the fact that seven months have elapsed since the utilities filed their STPPs on May 15, 2003, each IOU shall update its short-term plan by compliance advice letter within 30 days from the effective date of this decision to reflect more recent fuel price forecasts and resulting changes to the loads/resource capacity and energy balance tables and residual net open estimates. Each utility shall meet this requirement by furnishing updated tables to its short-term plan in its compliance advice letter filing. Resubmission of the entire plan is not required.

H. Role of PRG

In D.02-08-071, the Commission approved the joint request of SCE, PG&E, TURN and the Consumers Union to create utility-specific PRGs comprised of eligible non-market participants. In D.02-10-062, the Commission approved the continuation of the PRGs for 2003. The concept of a PRG was first formally proposed as part of SCE's May 6, 2002 filing of its motion for Capacity

Procurement. In this filing, SCE stated that the PRG is a "Commission-authorized entity whose members, subject to an appropriate non-disclosure agreement, would have the right to consult with and review"[21] the confidential details of IOU procurement activity. The PRG would assess procurement activity and upfront reasonableness criteria and offer assessments and recommendations to the IOU when contracts are submitted for Commission review. Following this filing, SCE drafted a memo entitled Joint Principles for Interim Procurement. The three IOUs, TURN and the Consumers Union (CU) are signatories to these Principles. A Procurement Contract Review Process was established, endorsed by the PUC, and incorporated as Appendix B to D.02-08-071.

Each IOU's 2004 procurement proposal is based on the assumption that the PRG process will continue into 2004, and that there will be regular IOU-PRG consultations on proposed procurement and hedging activities. ORA and TURN also support continuation of the PRG in 2004. As TURN states:

> "The creation of the PRGs constitutes an innovative effort to involve utilities, consumers and state agencies in a forward-looking dialogue before formal filings are submitted for Commission approval. The impetus behind the formation of the PRGs - the switch to up-front approval standards under AB 57 - remains relevant for the foreseeable future."

If the PRG were to "sunset" at the end of 2003, PG&E has stated that as a default, it would pursue an on-going, informal dialogue with ORA and other non-market parties regarding proposed procurement and hedging activity.[22] We

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[21] SCE Brief on Generation Procurement, May 6, 2002, p. 11.

[22] Hearing Testimony, Witness Jeung, July 25, p. 4100.

note, however, that in the absence of a PRG process, this consultation would be strictly ad-hoc and at the discretion of the utilities.

SCE witness Kevin Cini testified during the hearing that, "…I actually think that the PRG process provides more visibility to the Commission and the parties that have access to SCE confidential information than if we had some other process in place."[23] Mr. Cini goes on to say, "Our procurement plan contemplates the PRG continuing to 2004. The PRG is an integral part of our procurement plan."…"we would still want to work with the consumer advocates in an informal way, where we would still share with them business issues that we have….and we would share with them the models that we're considering using to get their feedback on that…"

Though it only has consultative and informal advisory functions, the Commission finds the PRG to be an effective vehicle for IOU dialogue with Commission staff familiar with the nuances of their energy portfolios and the necessary policies/strategies needed to mitigate portfolio risks. The PRG has played a valuable role in identifying potential issues or concerns regarding IOU procurement. Perhaps the most significant achievement of the PRG process since its inception is the reduction of contested or litigated procurement transactions. As stated by TURN in its closing brief:

> "Many of TURN's suggestions have been incorporated into procurement activities without the need for time-consuming and combative litigation. As result, the amount of actual litigation associated with individual transactions and strategies has been limited to a few isolated disagreements . . . ." (p. 38.)

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[23] Hearing Testimony, Witness Cini, August 7, pp. 5222-24.

PRG members have sufficient access and dialogue with the utilities, that they can advise utilities of potentially contentious issues or procurement activities prior to the utility executing a trade. The value of this collaborative process is accurately portrayed by TURN in its closing brief:

> "Without a PRG structure, TURN and other non-market participants would be denied the opportunity to learn about ongoing activities and challenges in real-time and instead would be forced to review materials underlying the Advice Letter filings for the first time after the decisions had been made and submitted for approval." (p. 39.)

We find that the PRG process has been beneficial, and we authorize its continuation through the end of 2004. As provided for in D.02-10-062, each utility shall meet and confer with its PRG on a quarterly basis. Each PRG has the option of conducting meetings by teleconference. When PRG meetings are conducted by teleconference, we urge each utility to provide electronic copies of meeting materials to PRG members in advance of the meeting, and to provide adequate time for review of such materials prior to the meeting. During the quarterly meetings, each utility shall review with its PRG the utility's open position, changes in market conditions from the previous quarter, including gas and electric prices, hedging strategies going forward, and the necessity of filing a plan update. PRG meetings may be held more often than quarterly under circumstances when portfolio risk exceeds the CRT as described elsewhere in this decision.

Even with an incentive mechanism and upfront standards and criteria in place, the PRG can serve during 2004 as a "streamlining" entity, interfacing with utilities and helping to facilitate utility filings at the Commission, thereby making the filing process more efficient. The PRG structure allows for substantive review of and input to time-sensitive procurement and risk management proposals, since PRG members (including Energy Division staff) have advance access to the large volume of data and market information inherent in procurement report filings.

We note that the PRG's role is an advisory one, and it does not preclude DWR's authority to conduct a reasonableness review. The Commission has recognized this authority, and now reiterates its recognition of Article 4.2 of the Rate Agreement, which stipulates DWR's authority to determine just and reasonable costs.

I. Modification and Approval of Short-Term Plans

In its short-term plan, SCE does not use the pro-rata cost allocation of DWR contracts that the Commission adopted in D.02-09-053 and confirmed in D.02-12-045 and D.02-12-069. From the Commission's perspective, there are three disadvantages to SCE modeling this methodology. First, as it has modeled a cost allocation methodology not authorized by the Commission, we are now asked to approve a procurement plan that may include skewed measures of procurement cost and portfolio risk relative to estimates under the Commission-approved pro-rata cost allocation. Second, modeling based on a cost allocation methodology not approved by the Commission undermines the principle of transparency, on which the Commission bases its procurement policy. Third, developing policy that dictates the appropriate "signals" for operating, procurement and management of utility portfolios is within the purview of the Commission and is not a utility-specific determination.

Further, there is no record in this proceeding on methodologies for cost allocation of the DWR contracts, nor have other parties had the opportunity to be heard on this issue. The appropriate forum for revisiting this methodology is the 2004 DWR revenue requirement proceeding. That proceeding has been bifurcated into two phases. In the first phase, the IOUs have been ordered to adopt an interim allocation for the 2004 revenue requirement using the methodology adopted for 2003 in D.02-12-045. In the second phase, a final allocation methodology for 2004 will be litigated on a less expedited schedule. The final allocation methodology will be applied retroactively to January 1, 2004.

The application of the final cost allocation methodology can and will be applied retroactively, due to the fact that it involves a regulatory, non-market process. However, given procurement activity in financial markets, any incremental portfolio risk incurred as a result of modeling based on a non-approved methodology cannot be "trued up." SCE must amend its plan and model its procurement costs and estimate portfolio risk based on the pro-rata allocation approved by the Commission.

PG&E requests the Commission relieve it of its responsibilities to manage gas hedging for its allocated DWR contracts in the event it does not have sufficient credit capacity to enter into such hedges given the other demands for its limited credit capacity. We deny PG&E's request here. PG&E's responsibilities are set forth in its Operating Agreement with DWR and any changes to that agreement must be done through negotiations with DWR and/or a petition to modify D.03-04-029.

PG&E requests the Commission extend the disallowance cap we adopted in D.03-06-067 to the 2004 short-term plans. We should do this, and on the same terms as we adopted in D.03-06-067, and confirmed in D.03-06-076 and D.03-10-090. We do not entertain PG&E's request to extend the scope of the disallowance cap as we have previously addressed this issue in the above-mentioned decisions.

We adopt the short-term plans of the respondent utilities as modified herein. The effective date of the short-term plans is today.

Each utility should file by compliance advice letter within 30 days of the effective date of this decision revisions to its short-term plan that conform to this decision. These plans shall conform to all Commission decisions unless specific findings are made here to change a previous Commission decision.

IV. QFs

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 our Interim Opinion, QF power does provide 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.)

We continue to strongly support the foregoing proposition, and in this Decision, we shall continue in 2004 the policies relating to QFs that we adopted for 2003 in our Interim Decision, D.02-08-071. In today's decision, we only address procurement planning activities for the short term. Accordingly, we shall not engage in a detailed discussion of the parties' positions on all of the QF-related issues that were addressed in: (a) the hearings that took place in the later part of 2003, (b) the subsequent briefing, and (c) the Proposed and Alternate Decisions issued on November 18 and December 4. Rather, we shall focus only on those QF-related issues that must be decided now in order to assure the continuing availability of QF power during 2004.

A. Parties' Positions

1. Utility Recommendations

PG&E, SCE, and SDG&E have proposed to not automatically renew expired QF contracts, but differ in their willingness to do so. SDG&E is the most willing of the three and does assume that its QF power deliveries will remain relatively constant throughout the forecast period, and that expired QF contracts will be renewed under certain conditions. However, all three utilities agree that the Commission should reexamine SRAC pricing to ensure that utility avoided cost more accurately reflects the cost of their replacement power alternatives. SDG&E is amenable to renewing expired QF contracts through the use of

Standard Offer 1 (SO1) contracts that would be renewed annually based on need. SDG&E is opposed to the use of QF-only auctions.

PG&E occupies the middle-ground on QF issues with its proposal to offer one-year SO1 contracts with modifications pertaining to: (1) the provision of 1,000 discretionary curtailment hours, both financial and physical curtailment, (Tr.5744, lines 2-9), although the detailed protocols on specific curtailment frequency, duration, and notice provisions were not specifically set forth; (2) providing for an option to terminate a contract once the seller enters into a winning RPS bid; (3) revisiting SRAC methodologies; and (4) the opportunity for QFs to participate in any upcoming power solicitations.

SCE stands alone at the other end of the spectrum with its solicitation-only proposal. SCE contends that its Public Utility Regulatory Policies Act (PURPA) obligations will be fully satisfied simply by affording QFs the opportunity to participate in upcoming solicitations for renewable and/or non-renewable contracts. SCE asserts that California and other states have considerable discretion in implementing PURPA's mandatory purchase requirement, and that the demise of the California Power Exchange (PX) has not altered the basic proposition that PURPA may be properly implemented by providing QFs with the opportunity to participate in a competitive procurement process. SCE further notes that revival of mandated SO1 contracts would impose must-take obligations on the IOUs in all hours, including many hours when the true costs avoided by the QF purchases approach zero and may even be negative.

2. CCC Recommendations

CCC recommends that QFs should be (1) allowed to 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 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 also encourages the Commission to reject PG&E's proposal to incorporate 1,000 hours of annual curtailment into SO1 contracts. CCC contends that PG&E has not shown that the utility's avoided costs are negative in this many hours, nor has the utility provided details on how it would administer such curtailments. CCC states that this issue would be best considered during a comprehensive review of SRAC pricing issues.

3. CAC/EPUC's Position

On QF issues, CAC/EPUC generally took the same position as CCC. However, CAC/EPUC emphasized the importance of state law, as set forth in PU Code § 372, in encouraging the Commission to support the continued development, installation, and interconnection of clean and efficient self-generation and cogeneration resources, and to improve system reliability for consumers by retaining existing generation and encouraging new generation to connect to the electric grid.

4. ORA's Position

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.

5. Discussion

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

For purposes of this Decision, we only need to specifically address the issue of existing QFs with contracts that have expired during 2003 or will expire during 2004. This is because we shall be discussing the larger issues associated with longer-term procurement of QF power in our upcoming policy decision.

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 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 <u>additional</u> 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 the short-term focus of this Decision, we do not accept the IOUs' proposal at this time, and we direct the IOUs to renegotiate expiring or expired contracts with existing QFs to cover calendar year 2004 on the terms discussed in further detail below.

We understand that most of the existing QF contracts will not expire before the end of 2005. Over the next two years, we expect to complete a thorough review of pricing policies relating to QFs. However, we need to make provision for those QF contracts that have either recently expired or will expire during the next year. Specifically, we should continue to provide interim treatment, as we did in D.02-08-071, for QF contracts expiring in the near term for which the QF and the utility do not reach agreement on the terms of a new long-term QF contract. Accordingly, the utilities shall continue to purchase power until December 31, 2004 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, 2005, or have already expired.

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 SRAC policy, the pricing terms of the contract shall be modified to reflect said revised SRAC policy as of the effective date of the Commission decision adopting a revised SRAC policy.

(1) New QFs During the Interim Period

Although we are directing the IOUs to extend expiring or expired contracts with existing QFs for another year, we are not allowing for any new QF contracts with new QF facilities during this short interim period in which we shall be evaluating how the QFs will fit into the IOUs' procurement planning processes on a long term basis. This should not prejudice any prospective new QF, as the electric restructuring related suspension we adopted in D.96-10-036 continues, until we complete work on the long term procurement issues that are the subject of this very complex proceeding.

Thus, as to new QFs, we direct the utilities not to enter into any new contracts until we have issued a decision on the long-term procurement issues on which hearings have already been conducted, and which remain under consideration in this proceeding.

(2) Revision of SRAC Prices

All three utilities contend that revision of the current SRAC methodologies for determining QF energy and capacity payments is needed. For many years now, SRAC has been approximated through time-differentiated energy prices (set once a month) and time-differentiated capacity prices (set annually). However, there is evidence on the record in this proceeding that indicates that the current SRAC energy pricing methodology has yielded prices in excess of spot market prices for significant periods of time.

The Commission has established SRAC methodologies used to calculate avoided cost energy and capacity payments for QF power. Per the requirements of Pub. Util. Code § 390, SRAC energy prices are tied to natural gas spot border prices, which have not necessarily reflected the more diverse utility portfolio that should be reflected in a utility's avoided cost. The result of the current SRAC pricing system has been that utilities have paid too much for QF power in certain time periods relative to market prices, in some cases, even just on the basis of energy prices not withstanding capacity payments. More specifically, based on current SRAC time of use factors, utilities have paid too much for QF power at certain times of day.

Because of this pricing problem, the Commission has also authorized utilities to purchase financial derivative products to hedge the QF price risk created, in part, by the approved SRAC methodology, which has been greatly affected by the volatility in the natural gas market over the past several years. In fact, the utilities have expended considerable sums of money hedging QF price risk resulting from this spot market-based (and in part Legislatively-mandated) avoided cost pricing formula. The amount of this hedging activity also indicates that the current avoided cost pricing formula has not reflected utility avoided cost either as accurately as we had hoped or as precisely as we would like to see in the future.

Accordingly, in our view, there is a pressing need to revisit the SRAC pricing system, which will accurately and fairly set utility avoided cost prices both under current and expected future market conditions and with an eye toward diverse utility resource portfolios.

In fact, Section 390 is now something of an artifact of the AB 1890 electric restructuring landscape, for the reason that Section 390 can never be fully implemented in accordance with the provisions set forth in Section 390(c) due to the demise of the PX.

As the foregoing discussion demonstrates, the SRAC energy pricing formula is now out-of-date. The capacity pricing component of the SRAC formula is also problematic, because the QFs receive capacity payments in addition to energy payments. With SRAC energy prices that can now be above market prices, the additional capacity payments that QFs receive could compound any inequity to the utilities and their ratepayers of the current SRAC pricing formula.

The Commission should carefully consider how to modify the SRAC methodology and whether to seek legislative changes to Section 390. We have a two-year window until most existing QF contracts begin to expire, and we should craft a remedy in the new OIR that better matches QF contracts with the actual needs and economic alternatives of the IOUs. Because it is so important that the current methodologies to establish SRAC be modified, we are directing the Commission staff to immediately begin work on a draft Order Instituting Rulemaking (OIR) that will examine and propose appropriate modifications to the SRAC methodology.

(3) PG&E's Proposed 1,000 Hours Curtailment Proposal

PG&E has proposed to offer SO1 contracts to QFs whose contracts have expired, provided the contract is mutually agreeable with possible annual renewal. As part of that contract proposal, PG&E included an updated curtailment provision, which would allow the utility, at its discretion, to physically and financially curtail such QF contracts up to 1,000 hours annually. PG&E contends that its proposal should be adopted for several reasons: (1) baseload power is not needed until after 2008, (2) allocated DWR contracts result in more energy than PG&E can use in many hours during the year, and (3) the 1,000 curtailment hours provision was previously approved by the Commission in connection with the Interim Standard Offer No. 4 Curtailment Option B. PG&E further contends that its 1,000-hour curtailment proposal is very reasonable and is perhaps overly generous, given that PG&E does not need additional generation during the next several years. (PG&E Post-Hearing Brief, September 15, 2003, pp. 85-87).

We are unpersuaded by PG&E's arguments on this issue. PG&E's 1,000-hour curtailment proposal is not the result of any detailed avoided cost calculations based upon an approved avoided cost methodology or concept. However, the planned hearings on modifications to SRAC should address PG&E's concerns, and will provide a more reasoned basis for the type of SRAC payment adjustments that PG&E’s proposed contract provision seeks to effectuate.

V. Energy Efficiency

A. Procurement Energy Efficiency Funding Levels for 2004-05

In D.02-10-062, we established policy priorities for resource acquisition for utility long- and STPPs. In that decision we identified energy efficiency as a priority resource and ordered utilities to include all cost-effective energy efficiency in their portfolio proposals.

> "Utilities should include in their plans procurement of baseload energy reductions in the form of energy efficiency. Utilities should consider investment in all cost-effective energy efficiency, regardless of the limitations of funding through the Public Goods Charge (PGC) mechanism."

In D.02-10-062, we also ordered utilities to submit long-term procurement plans, with estimates of energy efficiency savings projections for the first year, five years, and twenty years. PG&E, SCE, and SDG&E filed their long-term plans with the Commission on April 15, 2003. Each plan included estimates of energy efficiency resources they propose to acquire for these time periods.

The following table shows utility projected procurement costs (in millions of dollars) for energy efficiency programs for the years 2004 through 2008.

Utility	2004	2005	2006	2007	2008	Total
PG&E	25	50	50	75	100	300
SCE[24]	60	60	60	60	60	300
SDG&E	25	25	25	25	25	125
Total	110	135	135	160	185	725

[24] SCE's energy efficiency costs from their "referred plan."

B. Parties' Positions

No parties opposed utility energy efficiency procurement proposals. In its long-term plan testimony, ORA analyzed the cost-effectiveness of the energy efficiency component of the three utilities' long-term procurement plans over the first five years of the plan, finding each utility's proposal cost-effective. CEC's long-term plan testimony supported the inclusion of energy efficiency program elements in the long-term plan that go beyond the limits of PGC funding levels and recommended acceptance of utility energy efficiency proposals in its opening brief (p. 13). The "Joint Parties" recommendation (CEC, ORA, TURN, SCE, SDG&E, PG&E) also supports the additional proposed energy efficiency programs. NRDC in its long-and short-term plan testimony supports Commission authorization of utility energy efficiency procurement proposals and urges the Commission to allow utilities the flexibility to capture additional cost-effective efficiency resources that have been identified in potential studies. Finally, TURN urges the Commission to authorize only funding levels for energy efficiency resource acquisition in this proceeding, with specific program selection to be accomplished in R.01-08-028.

C. Discussion

Utilities approach the energy efficiency component of their long-term plans in different fashions. Both SDG&E and SCE worked directly with a contractor, Kema-Xenergy, to determine the potential for energy efficiency in their service territories, focusing on the several options for capturing the energy efficiency resource available in their territories. PG&E developed its long-term proposal based on forecasts of its net-residual short needs, matching these to programs that deliver energy savings and peak demand reduction measures with load profiles that reduce demand and save energy at times of forecasted need. We agree with NRDC and the City of San Diego that these approaches result in utility plans that capture "some," but not "all" of the energy efficiency potential identified in the latest studies of the available potential of energy efficiency in the utility service territory.[25] Nonetheless, each utility will need time to ramp-up enhanced existing and new energy efficiency programs. For this reason, we are inclined to accept utility long-term energy efficiency plan proposals as proposed.

The utilities' long-term plans identify procurement funded energy efficiency program activities for the five-year period 2004-2008. In this decision we authorize utility procurement energy efficiency budgets for the two-year period 2004 and 2005. We limit these initial procurement energy efficiency activities to this two-year period to ensure consistency across the Commission's entire portfolio of energy efficiency programs, with a specific goal of ensuring consistency with efficiency program activities authorized in this proceeding and those authorized in the Commission's Energy Efficiency R.01-08-028. Consistent with the July 3, 2003, Assigned Commissioner's Ruling (ACR), we choose this two-year program horizon as an interim-step to allow the Commission to review and address key issues identified in the ACR. Included among these are: long-term administration of Commission authorized energy efficiency programs; duration and cycle of these programs; energy efficiency goals; performance incentives and related issues. In this decision, we therefore maintain the status quo in term of program administration and other identified issues. By taking

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[25] M. Rufo and F. Coito, California's Secret Energy Surplus: The Potential for Energy Efficiency, Xenergy Inc., for the Energy Foundation and the Hewlett Foundation, 2002 www.energyfoundation.org/energyseries.cfm

this approach, we balance the advantages of a multi-year (2-year) planning and budgeting cycles with the reality of the time needed by the Commission adequately deliberate on and resolve these questions. We refer parties to our discussion below of energy efficiency program administration and other key issues identified in the July 3 ACR. We also believe that this authorization is necessary prior to December 31, 2003, in order to ensure a timely and coordinated beginning to all 2004 energy efficiency programs.

In summary, we should authorize procurement energy efficiency budget levels for the utilities for 2004 and 2005 as follows: PG&E - $25 million for 2004 and $50 million for 2005; SCE - $60 million for 2004 and $60 million for 2005; SDG&E - $25 million for 2004 and $25 million for 2005.

D. Program Selection Criteria

At the July 16, 2003, PHC, we asked parties to comment on program evaluation and selection criteria for energy efficiency activities funded here. At that time, we suggested parties comment on whether these programs should be evaluated using four specific criteria: long-term energy savings, cost-effectiveness, peak savings, and equity among rate classes, or utilizing other criteria for selection of procurement energy efficiency programs, such as those subsequently adopted in D.03-08-067 in R.01-08-028.

1. Parties' Positions

Parties commenting on program selection criteria proposed several different approaches. SDG&E supports use of three selection criteria for evaluation of procurement energy efficiency programs: long-term annual energy savings, cost-effectiveness, electric peak demand savings. In its testimony, NRDC notes that all programs must be "cost-effective," and recommends three criteria, including long-term annual energy savings, electric-peak demand savings, and the addition of "equity between customer classes." The ORA testimony focuses on the need to have a consistent Commission energy efficiency portfolio and recommends use of the same criteria for procurement programs as those used to evaluate PGC funded energy efficiency programs, including proposers' demonstrated success in implementing energy efficiency programs.

2. Discussion

Utility long-term plan forecasts project expected energy savings and demand reductions from both procurement funded and PGC funded efficiency programs. As such, these programs, whether PGC or procurement funded, are part of a comprehensive portfolio of energy efficiency resource acquisition programs to be authorized by the Commission. Consistent with our desire to proffer a uniform energy efficiency portfolio, we agree with ORA's comments that the Commission should evaluate and select utility 2004 and 2005 procurement energy efficiency proposals using both the selection process and primary and secondary selection criteria adopted in D.03-08-067. These primary criteria include: cost-effectiveness, long-term savings, peak demand reductions, equity considerations, ability to overcome market barriers, innovation, and coordination with other programs.

E. Procurement Energy Efficiency Program Submissions, Evaluation and Selection

For 2004-2005 utilities submitted to the Commission a total of eighteen[26] procurement energy efficiency program proposals totaling $244,586,000 over the

[26] This count includes only the PG&E single program proposal in the PGC Rulemaking, which is for all of the procurement related energy efficiency program activity it proposes to implement in 2004 and 2005. It does not include the count of specific

Footnote continued on next page

two-year period 2004-2005. Total projected energy savings and demand reduction from these programs are: 1,675,845 megawatt-hour (MWh) and 336.5 megawatt (MW). PG&E proposed a single program effort for a cost of $75 million over the two-year period. Projected two-year energy savings for PG&E are 466,883 MWh with projected demand reductions of 124.4 MW. SCE proposes 8 statewide procurement energy efficiency programs and 2 local programs at a two-year energy cost of $120 million with a two-year energy savings goal of 956,994 MWh and a demand reduction goal of 168.2 MW over the period. SDG&E proposes two statewide and 5 local programs for a total cost of $49,586 million over the two-year period. Projected energy savings over this period are 251,968 MWh and 43.9 MW in demand reductions.

The following table shows the projected incremental energy efficiency program costs, energy savings, and demand reductions from utility procurement programs in 2004 and 2005 as compared to estimated program costs, savings and demand reductions from proposed 2004-2005 PGC funded programs.[27]

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program activity proposed by PG&E that include activities in five statewide residential and nonresidential programs

[27] Based on 2004-05 utility PGC and Procurement Submissions (9/23/03)

1. Projected Utility Energy Efficiency Procurement and PGC Funded Cost, Energy Savings & Demand Reductions for Procurement and PGC Funded Programs

2004-2005

	PGC Budget ($million)	Procurement Budget ($ million)	PGC Energy Savings (MWh)	Procurement Energy Savings (MWh)	PGC Demand Reductions (MW)	Procurement Demand Reductions (MW)
PG&E	257,932,300	75.0	1,069,568	466,883	196.9	124.4
SCE	182,692,272	120.0	483,636	956,994	107.9	168.2
SDG&E	76,746,020	49.6	259,015	251,968	48.5	43.9
Total	**517,370,592**	**244.6**	**1,069,568**	**1,675,845**	**353.3**	**336.5**

Parties having a further interest in reviewing specific utility energy efficiency procurement proposals may view these on the Commission's website at http://www.cpuc.ca.gov.

To ensure consistent evaluation of the Commission's total energy efficiency portfolio being developed in both this proceeding and in R.01-08-028, the ALJ directed the utilities to submit in R.01-08-028 the 2004-2005 procurement energy efficiency proposals for evaluation at the time of Commission review and evaluation of PGC funded energy efficiency program proposals. The Commission reviewed these programs by using the process and criteria described above.

In this decision we authorize only the overall funding levels for procurement energy efficiency programs. We refer program specific review and approval, including required programmatic or budgetary modifications to utility procurement program proposals, to the Energy Efficiency R.01-08-028 where the Commission will select a balanced portfolio of utility and non-utility energy efficiency programs for 2004 and 2005. This Commission expects to authorize its portfolio of energy efficiency programs in R.01-08-028 before the end of 2003.

F. Cost-Recovery Mechanism for Procurement Energy Efficiency Activities

1. Parties' Positions

Each utility proposes somewhat different mechanisms for cost-recovery of procurement related energy efficiency activities. PG&E proposes the establishment of an Incremental Procurement Energy Efficiency Balancing Account (IPEEBA) to record the costs of authorized incremental energy efficiency programs as these costs are incurred.[28] PG&E would request recovery of these costs in subsequent ERRA proceedings. SCE proposes to record expenses for procurement authorized energy efficiency programs directly in its ERRA, and request approval of these during its October annual ERRA filing.[29] SCE testifies that such an approach is reasonable as such expenses directly benefit bundled service customers who take generation and procurement related services from SCE. SDG&E, in its testimony, proposes that incremental procurement energy efficiency costs be subject to recovery through a non-bypasssable charge to all customers and requests the Commission establish a balancing account for costs and revenues recorded in the balancing account.[30]

In its long- and short-term procurement plan testimony, NRDC supports utility cost-recovery for the actual costs incurred for procurement energy

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[28] PG&E, Chapter 3, p. 10.

[29] SCE, V.2, C. Dominiski, pp. 87-88.

[30] Smith / SDG&E, Tr. 30 / 3650, 3667-68.

efficiency programs provided that these programs meet Commission rules for cost-effectiveness and rigorous evaluation, measurement and verification. The Joint Parties' recommendation also endorses utility cost-recovery for incremental procurement energy efficiency programs identified in their long- and STPPs plans.

2. Discussion

In deciding which of the proposed cost-recovery mechanisms best serve the needs of providing utilities cost-recovery in an expeditious and fair manner, we are cognizant of the fact the SCE's proposal, if adopted, holds the potential for increasing recorded costs in the ERRA account to a degree that could trigger the adjustment mechanisms within that account. Both PG&E and SDG&E propose the establishment of balancing accounts to record energy efficiency costs and revenues outside the ERRA. SDG&E also proposes that these costs be funded through a non-bypassable surcharge on all customers.

After reviewing the various proposals, we find that SDG&E's proposed approach to implement a non-bypassable surcharge on all customers to pay the costs of energy efficiency program funding authorized in this proceeding provides a simple to understand, fair, and expeditious mechanism for providing utilities cost-recovery for procurement related energy efficiency activities. Moreover, this approach provides symmetry to the current Commission approach for funding Public Goods Charge programs as enunciated in Public Utilities Code § 381. In authorizing a non-bypassable surcharge to pay the costs of procurement efficiency program, the Commission remains mindful of the need for continued coordination of procurement efforts related to cost-recovery with related issues that may arise in R.01-08028. We therefore order the respondent utilities to establish a one-way Procurement Energy Efficiency and Balancing

Account (PEEBA) to track the costs and revenues associated with authorized programs in this proceeding. Costs associated with these accounts should be submitted simultaneously with utility monthly ERRA filings to the Energy Division for review on a monthly basis. Further, within 20 days of this decision, we order the utilities to file advice letters establishing the methodology and surcharge rate for incremental procurement energy efficiency programs for program year (PY) 2004 and 2005.

G. Performance Incentives for Procurement Efficiency 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.

2. Discussion

We intend to address in detail an approach to incentive mechanisms in our long-term policy decision forthcoming as soon as possible after January 1, 2004. In the meantime, we put parties on notice that any discussion of incentive mechanisms, whether supply-side or demand-side, will be carefully coordinated by the assigned administrative law judges (ALJs) and Commissioners in rulemaking proceedings relevant to particular resources (for example, energy efficiency incentives in R.01-08-028 or demand response incentives in R.02-06-001). The ALJs and Commissioners in these and other related proceedings may hold joint workshops or PHCs to begin to develop proposals for a variety of incentive mechanism options. Through careful coordination, we can ensure that any incentive mechanisms considered for specific resource types are consistent with our overall procurement goals and incentive policies established in this proceeding. To that end, any notices of PHCs or workshops to address any incentive-related issues will be sent to the service lists in all related proceedings, to encourage participation by all interested parties in this coordinated effort.

VI. 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 MW 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 price-responsive programs already authorized in D.03-06-036. 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" Airconditioning (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 in 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.

VII. Renewables

In general, we find 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. This can be largely attributed to the fact that at the time the utilities prepared their filings, RPS program development was in progress and the Commission had yet to issue and adopt D.03-06-071. We note that the IOUs will file separate renewable procurement plans pursuant to Pub. Util. Code § 399.14(a)(3), thus the 2004 procurement plans currently under consideration do not constitute a filing of the required renewables plans. Our approval of the 2004 procurement plans today does not "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. Interim solicitations will follow guidelines already established by the Commission, and are also addressed below.

We will address long-term renewables issues in a subsequent decision and in the forthcoming RPS rulemaking. This Decision will only address short-term issues necessary to ensure that the 2004 plans are consistent with the RPS.

D.03-06-071 adopts rules for RPS elements as required by Pub. Util. Code § 399.14(a)(2), and addresses other issues such as creditworthiness and renewable energy credits. The Assigned Commissioner's Ruling Specifying Criteria for Interim Renewable Energy Solicitations (ACR) dated August 13, 2003, provides criteria for any interim renewables solicitations conducted by a utility prior to a full RPS solicitation implementing the utility's renewable procurement plan. While we strongly discourage pre-RPS solicitations, any renewables solicitations that do occur prior to a full RPS solicitation will follow the criteria set forth in the ACR.

In its 2004 plan, PG&E proposes that the Commission adopt an interim all-in benchmark of 5.37 cents per kilowatt-per hour (kWh), and subsequently review and update the benchmark. The Commission will develop the MPR to accomplish this goal. Additionally, the ACR provides guidance on use of interim benchmarks. Our attention is now focused on refining the methodology for the

MPR, and as such we do not adopt an interim benchmarking process. We therefore decline to adopt PG&E's request for an interim all-in benchmark of 5.37 cents per kWh.

PG&E also proposes to conduct a renewables solicitation within 60 days of approval of its 2004 procurement plan. PG&E proposes to sign only one-year contracts, due to its credit status. In its testimony, ORA states that such short-term contracts will "increase the chances of a utility having greater difficulty in meeting its RPS in the future…"[31] Although the term lengths addressed in D.03-06-071 should apply to RPS solicitations, one goal of the RPS program is to foster a long-term market for renewable energy by providing contracts of 10 or more years. We do not find that PG&E's proposed short-term solicitation adheres to this principle. We will address PG&E's credit status at a later time, noting here that the Commission may determine that PG&E can undertake renewables procurement prior to creditworthiness subject to specific conditions. We deny PG&E's request for one-year renewables contracts, and focus attention instead on progress towards a full RPS solicitation in early 2004.

In its comments on the proposed decision, SDG&E calls attention to footnote 52 of D.03-06-071, which states:

> "The SDG&E/TURN proposal does allow for shorter-term contracts to be bid by developers. Any such shorter-term contracts require express Commission approval."

In an RPS solicitation for products with 10, 15, and 20 year terms, developers may submit non-conforming bids. PG&E's proposed solicitation only

[31] ORA testimony, p. 67

offers short-term contracts, so our denial of such a solicitation remains consistent with the terms adopted in D.03-06-071.

The IOUs recommend meeting their QF obligations under PURPA in various ways, including competitive solicitations (SCE proposal) and one-year SO1 contract extensions (PG&E proposal). SDG&E refers to holding an "auction" for QF contracts. While renewable bidders are welcome to participate in all-source solicitations outside the RPS bidding parameters, a unique MPR will not be developed for such solicitations. Therefore, bidders must not anticipate the use of Supplemental Energy Payments (SEP), nor shall bids contain SEP contingencies. This is consistent with the August 13 ACR. Bidders may, however, retain previous CEC awards, as stated above. The utilities may receive and select cost-effective renewables bids under an all-source solicitation, and the bid evaluation process must not treat those bids unfairly when compared with non-renewable product offerings. Additionally, any contracts resulting from these solicitations will count toward an IOU's RPS targets, provided the facilities are deemed eligible renewable resources.

We reaffirm that all renewables contracts must be filed for approval by the Commission by Advice Letter filing as required by D.03-06-071 and the ACR. Approval of the 2004 plans does not constitute a waiver of this requirement.

As we consider the utilities' long-term plans, we will require the utilities to provide more detailed estimates of their renewable resource profiles. 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. Meanwhile, the IOUs shall update their 2004 plans as appropriate to include any interim renewable procurement activity from 2003 and subsequent changes to the quantity of renewable energy delivered in 2004.

VIII. Procedural Process and Schedule for Future Filings

A. Quarterly Compliance Filings

On September 10, 2003, PG&E and SDG&E filed a joint petition to modify D.02-10-062, specifically to extend the due date of the Quarterly Procurement Plan Compliance Reports from within 15 days of the end of the quarter to within 30 days of the end of the quarter. Both utilities state that they need this additional time to prepare sufficiently detailed and comprehensive reports. Parties testified to the thousands of transactions that are included in the quarterly compliance filings. Therefore, we find PG&E's and SDG&E's joint petition reasonable and grant the relief sought, on a going forward basis, in this decision.

We also take this opportunity to address the procedural process under which we review these compliance filings. In D.02-12-074, in Section VI, we set a procedural process under which the Energy Division would review the quarterly compliance filings on an expedited basis, with a 30 day review period as a guideline, and then prepare a resolution with their findings and place it on the Commission's agenda. With the Commission's current staff resources, a full review of the filings cannot be done in these expedited timeframes. Rather, the Commission should look to streamlining its review by having the utilities provide an independent auditor's certification that procurement transactions were reviewed and verified to be in compliance with their adopted procurement plans. This procedure was discussed with SCE's witness Cini, who agreed that Energy Division, in consultation with the PRG, could select an outside auditor for this function.[32] Therefore, we find that the Energy Division should, in consultation with each utility and its PRG, select an outside auditor to review and verify that the quarterly compliance filings are in compliance with the adopted procurement plans, and the audit expenses should be paid by the utilities and recorded in a memorandum account. Given the large volume of transactions conducted each quarter, we recognize that sampling may be appropriate method for verification. A resolution for the Commission's agenda should only be prepared if Energy Division or the outside auditor find transactions or procurement practices that are not in compliance with the adopted plans.

B. ERRA Filings

ORA and SCE recommend that the Commission annually update the STPPs 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.

In today's decision we make no change to existing ERRA filing schedules, preferring to assess the merits of the ORA and SCE recommendations as part of the comprehensive policy decision forthcoming after January 1, 2004.

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[32] Transcript at 5225, Volume 42

IX. Final 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. Pursuant to Pub. Util. Code § 311(d) and Rules 77.2-77.5, 24 parties[33] filed comments on the proposed decision by December 8, 2003 and 11 parties[34] filed reply comments by December 15, 2003. We have reviewed the comments filed, and made changes as necessary to improve the technical accuracy of this decision. To the extent comments address issues deferred to our upcoming policy decision, they are not addressed in this decision, but will be addressed as necessary there.

Pursuant to Pub. Util. Code §1701.3(d), a final oral argument was held before a quorum of the Commission on December 2, 2003. Seventeen active parties presented argument. (48 RT 5927-6048.)

X. Assignment of Proceeding

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

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[33] The following parties filed opening comments: PG&E, SDG&E, SCE, ORA, TURN ,CEC, CPA, ISO, City of San Diego, City and County of San Francisco, NRDC, Navaho Nation, AReM, WPTF, IEP, CAC/EPUC, CCC, Joint Parties, Sempra Energy Resources, the Center for Energy Efficiency and Renewable Technologies (CEERT), Coalition of California Utility Employees, Duke Energy North America, Vulcan Power Company, and the Local Government Commission. In addition, the Department of Water Resources submitted letter comments. Finally, two entities filed motions to intervene for the purpose of submitting comments; the motion to intervene of the Ratepayers for Affordable Green Energy and the motion to intervene of Constellation NewEnergy, Inc are granted for the purpose of considering the comments each has filed.

[34] The following parties filed replies: PG&E, SDG&E, SCE, ORA, ISO, Navaho Nation, AReM, IEP, CAC/EPUC, CCC, and Ridgewood Olinda, LLC.

Findings of Fact

1. For 2004 only, it is reasonable for the utilities to procure resources sufficient to ensure that they meet their peak demand plus appropriate operating reserves.

2. The level of the operating reserve margin is determined by the Western Electricity Coordinating Council and is approximately 7% of peak demand.

3. Based on their filings, it appears that the utilities' planning reserve margins for 2004 are significantly above 7%.

4. The 5% of monthly need target on spot market purchases from D.02-10-062 provides a balance between procurement flexibility and reliability and it is reasonable to continue to require the utilities to justify a higher level.

5. The utility's short-term focus in the planning and procurement process should be on measuring the price risk exposure of its open portfolio position and managing that position, within a specified range of the consumer risk tolerance level, in a manner that ultimately leads to the procurement and dispatch of power in a least-cost manner.

6. SCE is in the process of developing a proprietary in-house model which it states can report TeVaR (To Expiration Value at Risk) to measure and report portfolio risk, and SCE is willing to have this model validated by an independent source.

7. Model validation will confirm that the Commission requirements for transparency, accuracy, and standardization in risk reporting are met.

8. The VaR approaches proposed by PG&E and SDG&E are appropriate for measuring and reporting portfolio risk.

9. The VaR product is a staple of the financial industry, used to provide a quick and succinct "snapshot" of the worst-case scenario for portfolio loss or exposure.

10. 99^{th} percentile portfolio risk reporting will provide additional price volatility information without unduly burdening the IOUs or the PRGs.

11. The Commission's risk reporting policy is guided by TURN's testimony that risk management standards should seek to protect bundled ratepayers against highly unlikely events.

12. The Commission has three primary oversight responsibilities in short-term risk management policy: (1) to specify the interim level of CRT; (2) to make sure each IOU has accurate and transparent tools in place to measure ratepayer risk exposure; and (3) to review and adopt utility procurement plans.

13. It is appropriate for the utilities to enter into contracts of up to five years in term to meet needs occurring in 2004.

14. Utilities should not lock in resources that would preclude Commission action in the long-term phase of this proceeding for the preferred resources identified in the "loading order" of the EAP.

15. It is beneficial to authorize specific procurement products and transaction types.

16. Negotiated bilateral transactions lack transparency and are more appropriately restricted to limited circumstances.

17. Today, the three utilities have all successfully resumed full procurement and the financial prognosis for PG&E is much improved. SCE has regained its investment grade credit rating, a fact that may be officially noticed.

18. In assessing the utilities' financial capabilities, the Commission considers issues which affect capital structure in tandem with those affecting immediate cash needs.

19. There are elements of credit risk related to collateral issues which transcend cash requirements.

20. It is essential to balance the cost of collateral against the risk of counterparty default.

21. The Commission has authorized PG&E, SCE and SDG&E to serve as limited agents for DWR for fuel management services associated with DWR long-term contracts.

22. PG&E, SCE and SDG&E's inherent responsibilities in managing and procuring for an integrated DWR/URG portfolio, subject to the requirements of least-cost dispatch, means that portfolio segregation is not possible.

23. Article 14.4 of PG&E's Servicing Order addresses conditions for force majeure, stating that any insolvency event shall not constitute force majeure.

24. It is appropriate for each utility to review market conditions relative to fuel and power price forecasts on a quarterly basis with its PRG and to file plan updates if the plan does not adequately capture current market conditions.

25. In its short-term plan, SCE does not use the pro rata cost allocation of DWR contracts adopted in D.02-09-053, and confirmed in D.02-12-045 and D.02-12-069.

26. It is beneficial to continue the PRG process through the end of 2004.

27. As SCE has modeled a cost allocation methodology not authorized by the Commission, its short term plan may include 'skewed" measures of procurement cost and portfolio risk relative to estimates under the Commission-approved pro rata cost allocation.

28. Modeling based on cost allocation methodologies not approved by the Commission undermines the principle of transparency, on which the Commission's procurement policy is based.

29. There is no record in this proceeding on methodologies for cost allocation of the DWR contracts, nor have other parties had an opportunity to be heard on this issue; therefore the appropriate forum for revisiting this methodology is the 2004 DWR revenue requirement proceeding.

30. 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.

31. In light of the continuing need for most of the power that QFs currently provide, and the short-term focus of this decision, the IOUs should renegotiate expiring or expired contracts with existing QFs to cover calendar year 2004.

32. The IOUs should not enter into any new QF contracts with new QF facilities during the short interim period in which we shall be evaluating how the QFs will fit into the IOUs' procurement planning processes on a long-term basis.

33. In this decision we authorize only the overall funding levels for procurement energy efficiency programs. We refer program specific review and approval, including required programmatic or budgetary modifications to utility procurement program proposals, to the Energy Efficiency Rulemaking 01-08-028 where the Commission will select a balanced portfolio of utility and non-utility energy efficiency programs for 2004 and 2005.

34. SDG&E's proposed non-bypassable charge approach for funding procurement energy efficiency provides a simple to understand, fair, and expeditious mechanism for providing utilities cost-recovery for procurement related energy efficiency activities.

35. It is appropriate to refer the issue of energy efficiency incentives to R.01-08-028 and demand response incentives to R.02-06-001, for disposition in those rulemakings. Future activities on all incentive mechanisms should be closely coordinated among all relevant proceedings, through the assigned ALJs and Commissioners hosting joint workshops or other similar mechanisms.

36. 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.

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

38. 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.

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

40. One goal of the RPS program is to foster a long-term market for renewable energy by providing contracts of 10 or more years. We do not find that PG&E's proposed short-term solicitation adheres to this principle.

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. AB 57 and SB 1976, codified in Pub. Util. Code § 454.5, provides a regulatory procurement framework for the Commission.

3. As required by Pub. Util. Code Section 454(b)(1), an electrical corporation's proposed procurement plan shall include an assessment of the price risk associated with the electrical corporation's portfolio.

4. Under AB 57, the Commission must assure that each electrical corporation optimizes the value of its overall supply portfolio for the benefit of its bundled service customers.

5. As specified in D.02-12-074 the utilities should analyze portfolio risk based on a probability distribution of risk factors.

6. Portfolio risk should be reported using TeVaR.

7. Standardized risk reporting is important in order to measure ratepayer risk.

8. Risk reporting should be a "roadmap," alerting the Commission to the relative risk in different time periods.

9. Under Pub. Util. Code Section 454.5, the Commission must assess the price risk associated with each utility's portfolio, ensure the utility has moderated its price risk, and ensure that the adopted procurement plan provides for just and reasonable rates, with an appropriate balancing of price stability and price level.

10. The Commission should authorize the utilities to continue to use the interim consumer risk tolerance level adopted in D.02-12-074.

11. Negotiated bilateral transactions should be separately reported in the utilities' quarterly compliance filings.

12. For transactions of greater than 90 days, the utilities should consult with the PRG.

13. 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.

14. D.03-06-076 sustained Standard of Behavior 1.

15. Where there are five or fewer counterparties in the relevant market, we should authorize the use of negotiated bilaterals for standard products for two categories of gas products cited by SCE: gas storage and pipeline capacity.

16. Each utility should update its fuel and power forecasts and submit updated loads/resource capacity and energy balance tables and residual net open estimates within 30 days from the effective date of this decision by compliance acquire letter.

17. Each utility should meet and confer with its PRG on a quarterly basis.

18. Commission approval of the utilities' Procurement Plans does not preclude the need for DWR to conduct after-the-fact reasonableness reviews.

19. QFs in operation and under contract to provide power to an IOU at any point between January 1, 1998 and the present date, whose contracts are set to expire before January 1, 2005, should be afforded interim treatment, consistent with that provided in D.02-08-071.

20. The Commission should carefully consider how to modify the SRAC methodology and whether to seek legislative changes to Section 390.

21. We do not have an adequate record on which to adopt an energy efficiency incentive.

22. Consistent with the July 3, 2003 Assigned Commissioner's Ruling in R.01-08-028, we should authorize utility procurement energy efficiency budgets for the two-year period 2004 and 2005.

23. We should authorize procurement energy efficiency budget levels for the utilities for 2004 and 2005 as follows: PG&E - $25 million for 2004 and $50 million for 2005; SCE - $60 million for 2004 and $60 million for 2005; SDG&E - $25 million for 2004 and $25 million for 2005.

24. Consistent with our desire to proffer a uniform energy efficiency portfolio, the Commission should evaluate and select utility 2004 and 2005 procurement energy efficiency proposals using both the selection process and primary and secondary selection criteria adopted in D.03-08-067.

25. Respondent utilities should establish a one-way Procurement Energy Efficiency and Balancing Account (PEEBA) to track the costs and revenues associated with authorized programs in this proceeding. Costs associated with these accounts should be submitted simultaneously with utility monthly ERRA filings to the Energy Division for review on a monthly basis.

26. In their future demand forecasts utilities should include expected energy savings from non-utility programs that operate in their service territories.

27. PG&E's demand reduction proposal should be adopted.

28. SCE's new ACCP programs and its funding request need to be reviewed in R.02-06-001 or its successor demand response rulemaking.

29. IOUs will file separate renewable procurement plans pursuant to Pub. Util. Code § 399.14(a)(3), thus the 2004 procurement plans currently under consideration do not constitute a filing of the required renewables plans.

30. Our approval of the 2004 procurement plans today does not "trigger" an RPS solicitation as detailed in D.03-06-071.

31. PG&E's request for an interim all-in benchmark of 5.37 cents per kWh for renewables should not be adopted.

32. PG&E's request for one-year renewables contracts should be denied; attention should focus instead on progress towards a full RPS solicitation in early 2004.

33. All renewables contracts must be filed for approval by the Commission by Advice Letter filing as required by D.03-06-071 and the ACR.

34. Energy Division should, in consultation with each utility and its PRG, select an outside auditor to review and verify the quarterly compliance filings, and the audit expenses should be paid by the utilities and recorded in a memorandum account. A resolution for the Commission's agenda should only

be prepared if Energy Division or the outside auditor find transactions or procurement practices that are not in compliance with the adopted plans.

INTERIM ORDER

IT IS ORDERED that:

1. We adopt short-term procurement plans, consistent with the terms of this decision, under which Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison (SCE) will operate in 2004. PG&E, SDG&E and SCE may begin transacting business under these approved plans as of the effective date of this decision.

2. PG&E, SCE, and SDGE shall undertake risk reporting using To Expiration Value at Risk (TeVaR), measured on a 12-month rolling basis, at a 99 percent confidence level.

3. We adopt the provisional use of SCE's model, subject to the model verification steps outlined in this decision.

4. PG&E, SCE and SDG&E shall file monthly portfolio risk reports with the Energy Division in 2004, and shall file quarterly reports in 2005.

5. We adopt PG&E's proposal for risk notification, consistent with the discussion in this decision.

6. As part of our approval of short-term plans, we authorize the utilities to enter into contracts with terms up to five years for procurement transactions with delivery beginning in 2004.

7. Utilities are authorized to enter into procurement transactions using the methods approved in this decision.

8. Until further notice, the parties shall abide by the affiliate transactions prohibition, as specified in Decision (D.) 02-10-062 and D.03-06-076.

9. PG&E's request for relief from responsibility to hedge gas on behalf of DWR to the extent that it'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, is denied.

10. When extending unsecured credit limits to non-investment counterparties, the utilities shall explore the use of credit mechanisms such as parent company or third party guarantees, letters of credit, surety bonds, and similar mechanisms.

11. When extending unsecured credit limits to non-investment counterparties, the utilities' credit assessment shall rely on master agreements with special parent or guarantor provisions for posting collateral and for assuring continuity of service.

12. Each investor-owned utilities (IOU) shall update its short-term plan by compliance advice letter within 30 days from the effective date of this decision to reflect more recent fuel price forecasts and resulting changes to the loads/resource capacity and energy balance tables and residual net open estimates. The update shall incorporate renewables procurement activity from 2003 and subsequent changes to the quantity of renewable energy delivered in 2004. Each IOU shall meet this requirement by furnishing updated tables to its short-term plan in its compliance advice letter filing (resubmission of all of the entire plan is not required).

13. SCE shall amend its short term plan and model its procurement costs and estimate portfolio risk based on the pro rata allocation approved by the Commission in its prior orders.

14. QFs in operation and under contract to provide power to an IOU at any point between January 1, 1998 and the present date, whose contracts are set to expire before January 1, 2005, shall be afforded interim treatment, consistent with that provided in D.02-08-071.

15. Consistent with the Assigned Commissioner's Ruling in R.01-08-028, we hereby authorize utility procurement energy efficiency budgets for the two-year period 2004 and 2005.

16. The specific procurement products and transaction methods enumerated in this decision are hereby authorized.

17. PG&E's demand reduction proposal is adopted.

18. SCE's new Airconditioning Cycling Programs and its funding request are not approved, but must be reviewed in the context of the Commission broader demand response efforts in R.02-06-001.

19. PG&E and SCE's joint petition to modify D.02-10-062 to extend the due date of the Quarterly Procurement Plan Compliance Reports from within 15 days of the end of the quarter to within 30 days of the end of the quarter, is granted, to the extent consistent with the discussion in this decision.

20. In consultation with each utility and its Procurement Review Group, Energy Division will select an outside auditor to review and verify the quarterly compliance filings, and the audit expense shall be paid by the utilities and recorded in a memorandum account. This process requires a resolution only in the event that the outside auditor finds transactions or procurement practices that are not in compliance with the adopted plans.

21. Respondent utilities shall establish a one-way Procurement Energy Efficiency and Balancing Account to track the costs and revenues associated with authorized programs in this proceeding. Costs associated with these accounts shall be submitted simultaneously with utility monthly Energy Resource Recovery Account filings to the Energy Division for review on a monthly basis. Within 20 days of the effective date of this decision, utilities shall file advice

letters establishing the methodology and surcharge rate for incremental procurement energy efficiency programs for Program Year 2004 and 2005.

22. The motion to intervene of the Ratepayers for Affordable Green Energy is granted, to the extent specified in this decision.

23. The motion to intervene of Constellation NewEnergy, Inc. is granted, to the extent specified in this decision.

24. Each utility should file a compliance advice letter within 30 days describing its revised short-term plan conforming to this decision.

This order is effective today.

Dated ____________________________, at San Francisco, California.