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Decision 02-12-074 December 19, 2002

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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APPENDICES A THRU C FILED UNDER SEPARATE SEAL

I. Summary

In this decision, we approve the short-term procurement plans, as modified by the confidential appendices developed here, for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). We also modify and clarify the cost recovery mechanisms and standards of behavior we adopted in Decision (D.) 02-10-062 and provide further guidance on the long-term planning process we will undertake in the next phase of this proceeding.

II. Procedural Background

On October 24, 2002 in Decision (D.) 02-10-062, the Commission adopted the utilities' procurement plans filed on May 1, 2002, as modified to reflect the changes ordered in D.02-10-062, inclusion of D.02-09-053's allocation of existing California Department of Water Resources (DWR) contracts, and any procurement done under the transitional authority we granted in D.02-08-071. We directed the utilities to file modified short-term procurement plans consistent with D.02-10-062 on November 12, 2002 and provided an opportunity for all interested parties to file written comments on the updated plans.

Edison and PG&E filed their updated plans on November 12 and SDG&E filed its updated plan on November 15, 2002.[1] Comments were filed on December 4, 2002 by California Biomass Energy Alliance (CBEA), Office of Ratepayer Advocates (ORA), and The Utility Reform Network (TURN) on PG&E and Edison's plans and ORA separately filed comments on SDG&E's plan on

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[1] SDG&E filed and was granted an extension of time in order to accurately reflect the newly renegotiated Williams contract.

December 5, 2002.[2] Reply comments were electronically served by each utility on December 6, 2002 and formally filed on December 9, 2002.

On October 15, 2002, Vulcan Power Company filed a motion pursuant to Rule 45 of the Commission's *Rules of Practice and Procedure* to become an active party. No party opposed this motion. Based on the reasons cited in the motion, we find good cause exists and grant the motion.

III. Ensuring the Utilities Resume Full Procurement on January 1, 2003

Both the Commission and the legislature have clearly expressed their intent to return the respondent utilities to full procurement on January 1, 2003, consistent with the utilities' statutory obligation to serve their customers and the provisions of Assembly Bill ABX1 X. We remain committed to that schedule and shall devote the full resources and authority of the Commission to see that Edison, PG&E, and SDG&E meet their obligation to serve by January 1, 2003.

In D.02-10-062, we gave specific direction on the manner in which Edison, PG&E, and SDG&E were to modify their adopted plans for the November 12 update filings. Our review of those filings shows that the utilities did provide a robust showing that took time to analyze. Our review was hampered by several efforts to reargue issues that were settled in D.02-10-062 and to include material on procurement plans that is not in compliance with our order. The comments of ORA and TURN confirm this.

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[2] The Cogeneration Association of California (CAC) did not properly serve its comments and, consequently, parties were not in receipt of the comments at the time of reply comments. On December 13, 2002, CAC filed a motion requesting consideration of its comments. Also on December 13, 2002, PG&E filed a motion for leave to file late comments in response to CAC's comments. We grant both motions.

Primarily to address this matter, we adopt a confidential appendix for each utility that sets forth the manner in which its November 12 procurement plan is modified. With the incorporation of the additions, deletions, and modifications set forth in each appendix into the November 12 filed plans, we adopt a revised updated procurement plan for each utility that meets the statutory requirements of Assembly Bill 57 / Senate Bill 1976[3] and all other provisions of the California Public Utilities Code.[4] We find that the utilities are capable of resuming full procurement on January 1, 2003 and order that they take all necessary steps to do so.[5]

IV. Approval of Updated Plans

In its comments, ORA states that it supports the approval of each utility's procurement plan for the purpose of allowing the utilities to resume procurement. However, ORA notes there are many areas that require ongoing review and potential revision and adjustment. Therefore, it requests that the Commission should make clear that acceptance of the utilities' plans does not preclude the adoption of adjustments or revisions to those plans.

Our approval of the updated procurement plans, as revised by each utility's adopted confidential appendix, is to put in place the upfront standards

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[3] SB 1976 modified a portion of Assembly Bill (AB) 57. We reference the statute here as SB 1976 / AB 57.

[4] All statutory references cite the Pub. Util. Code, unless otherwise noted.

[5] Edison requests that the Commission grant it an extension of time to resume full procurement. The 60-day requirement of SB 1976 it cites as the basis of its request, ran from our October 24, 2002 decision not this decision; this legal interpretation was earlier agreed to by Edison at hearings in July, when the schedule for this December update filing was first discussed. (See D.02-10-062, p. 3, footnote 2.)

and practices under which each utility will conduct procurement. Any adjustments or revisions that are requested by the utilities or other parties will be considered only on a prospective basis. As set forth in the utilities' procurement plans, D.02-10-062, and this decision, periodic compliance reviews and forecast proceedings will be undertaken.

TURN states that it finds PG&E's filing replete with characterizations and interpretations of the terms of AB 57/SB 1976 that TURN does not necessarily agree with or accept. TURN requests that the Commission specifically state that its approval of a procurement plan for PG&E does not in any way imply agreement with the utility's legal interpretations. TURN recommends that the focus here should be on the substance of the plan, not on legal arguments over theoretical disputes that may never arise in practice.

We agree with TURN. The legal interpretation of AB 57/SB 1976 is found in the Commission's decisions and the procurement plans must be in compliance with that interpretation. Several parties have filed applications for rehearing of Commission decisions in this proceeding. The legal merits of those challenges will be addressed by the Commission in separate decisions and, if appropriate, changes will be ordered to the procurement plans based on rehearing decisions.

On November 26, 2002, the Independent Energy Producers Association filed a petition for Commission review of redacted materials, seeking public disclosure of the basic range of assumptions regarding supply and demand conditions and utility expected requirements so that entities considering new project development or future marketing of existing generation can reasonably anticipate whether, in fact, there will be a market for their products and services.[6]

[6] A related motion was filed December 6, 2002 by The Western Power Trading Forum.

Opposition to IEP's motion was filed December 4 by Edison, December 9 by PG&E, and December 12 by SDG&E.

The material sought by IEP is market-sensitive information. We decline to perform the in-camera review requested by IEP. We deny the motion without prejudice and will allow IEP to renew its motion in the long-term planning phase.

We are concerned with specific language in the procurement plans that addresses DWR contracts and DWR/utility coordination procedures that may be contrary to other Commission orders. Nothing in the approved procurement plans should be contrary to the procedures adopted in the DWR/utility servicing agreements and operating agreements and the underlying decisions adopting those agreements. To the extent any material in the procurement plans filed by the respondent utilities is contrary to the referenced agreements and decisions, those sections are not approved here. We have identified and addressed such conflicts in the confidential appendices. In the event we have failed to resolve any conflicts, we instruct affected parties to bring such conflicts to our attention.

The confidential appendices list the specific modifications that this decision orders to the November procurement plans filed by the respondent utilities. These appendices are filed under seal and are subject to the May 1, 2002 protective order governing access to and the use of all protected materials in this proceeding. In addition, the utilities are not authorized access to each others' appendices. Confidential Appendix A modifies PG&E's November 12, 2002 Plan and November 22, 2002 supplemental revision, confidential Appendix B modifies Edison's November 12, 2002 procurement plan, and confidential Appendix C modifies SDG&E's November 15, 2002 procurement plan. Each respondent utility should obtain a copy of its individual appendix from Interim Chief Administrative Law Judge (ALJ) Carol Brown, or her designee, and is responsible for providing copies to all individuals authorized to receive this material within 5 days. The attorneys for ORA and TURN may obtain copies of all appendices directly from ALJ Brown, or her designee.

V. Elements of the Procurement Plans

A general issue raised in testimony supporting the procurement plans, is that today's energy markets may not be sufficiently liquid, i.e., a robust transparent competitive market, to provide the data necessary to support the showing for negotiated bilaterals that we adopted in Section VI.E. at page 34 of D.02-10-062. While the utilities asserted this, none provided an adequate measurement tool that could be used as an alternative. The Commission recognizes the market may not be robust but we do expect the up-front standard to be met by a strong showing. This could be, for example, by comparison to Request for Offers (RFOs) completed within one month of the transaction. We note that the issuance of an RFO does not mean that a bid must be selected but it would provide an evaluation of the market. The other option for the utilities is to update their plans.

We clarify that interutility exchanges do not need to meet the transparent competitive market standard, but rather have a separate cost effective standard under Section VI.D of D.02-10-062. We encourage the utilities to pursue the option of interutility exchanges. If they find our adopted standard has problems in today's market environment, they should confer with their PRG and propose an alternative.

A. Effective Duration of the Short-Term Plans

D.02-10-062 required the utilities to submit modified short-term procurement plan addressing procurement activities in 2003 and authorized contract terms for up to five years for transactions entered into under the plan.

D.02-10-062 also placed in motion a schedule for the development, review, and approval of long-term procurement plans covering anticipated procurement needs between 2004 and 2023.

PG&E's plan indicates that its plan is designed to cover procurement activities for a 12-month delivery horizon starting January 1, 2003. Edison's modified short-term plan presents residual net short (RNS) forecast data for calendar years 2003 through 2007 and acknowledges that its plan covers procurement activities executed in 2003. SDG&E's plan also notes that it is intended to address 2003 needs. In comments filed on the short-term plans, TURN expresses concern with PG&E's stated reference to limiting its procurement activities to only 2003. TURN states:

> While we would certainly consider it prudent for the utilities to limit any procurement that would extend beyond the end of 2003 until the long-term plan is approved, that does not mean that no power at all should be bought for January 2004 . . . until such approval is obtained. At least some degree of forward hedging for the early months of 2004 should logically occur in the later months of 2003, consistent with the other parameters set forth in the company's current plan. (Comments of TURN on PG&E Generation Procurement Plan, Unredacted, p. 4.)

We agree. Utility procurement of early 2004 needs should not await a final Commission decision on long-term procurement plans, although we recognize that a final decision on such plans is scheduled for November 2003. We therefore authorize the utilities to hedge 2004 first quarter residual net short positions with transactions entered into in 2003. Each utility should consult with its respective Procurement Review Group in the development of a hedging strategy for 2004 first quarter needs.

B. Forecasts of Loads and Resources

In D.02-10-062, we directed the utilities to include in their modified short-term procurement plans the allocated quantities of power provided from DWR's long-term contracts pursuant to D.02-09-053, as well as transitional procurement contract amounts as authorized in D.02-08-071. The updated procurement plans filed by PG&E, Edison and SDG&E contain the necessary forecasts of energy and capacity that will be available from the allocated DWR contracts.

With respect to transitional procurement, we note that PG&E's Advice Letter 2293-E filed on October 23, 2002, requesting approval of certain contracts, was approved by the Commission in Resolution E-3796 on November 21, 2002. PG&E has two additional transitional procurement resolutions awaiting Commission approval prior to the end of 2002: AL 2303-E for renewable resource contracts and AL 2302-E for QF SO1 contracts. On December 5, 2002, the Commission approved Resolution E-3803, approving certain renewable resource contracts filed by SDG&E in Advice Letter 1445-E. SDG&E does not have any other transitional procurement advice letters pending Commission approval at this time. Both the PG&E and SDG&E procurement plans include estimates of power to be provided under the terms of the approved and pending transition contract advice letters.

Edison's plan update, while it does reflect DWR contract allocation amounts, does not include transition contract quantities in the derivation of its forecast RNS position. On November 21, 2002, the Commission adopted Resolution E-3802 approving certain transitional procurement contracts requested by Edison in Advice Letter 1660-E filed on November 5, 2002. Edison has yet to file a renewables advice letter in accordance with the requirements of D.02-08-071, as we discuss further below, but does have AL 1664-E for QF SO1 contracts on file awaiting Commission approval before the end of the year. Edison's short-term plan states that it will count any transitional contract quantities approved by the Commission against the forward energy and capacity procurement limits ultimately adopted in its short-term plan update.

In order that the short-term plans accurately reflect the final disposition of transitional contracts approved by the Commission under the procurement authority granted in D.02-08-071, we direct PG&E and Edison to update their plans within 18 calendar days of the effective date of this decision. We do not require an update from SDG&E because its plan already reflects the contracts approved in Resolution E-3803.

With the exception of TURN, parties did not challenge the utilities' loads and resources assumptions underlying the forecast RNS in the short-term plans. Although Edison developed three different load forecasts and four direct access penetration scenarios for a total of 12 forecasts of UDC load, TURN recommends that an additional direct access load scenario should be developed. TURN argues that Edison's existing set of direct access load forecasts do not sufficiently account for the combined effects of: (1) new municipalization; (2) new community aggregation under AB 117; and (3) future direct access loads surpassing existing direct access levels. As a result of not adequately addressing these three factors in its procurement plan, TURN expresses concern that Edison might end up over-procuring power on behalf of bundled service customers.

Edison resists TURN's recommendation for development of an additional direct access scenario noting that the Commission suspended the right of customers to acquire direct access after September 20, 2001, and that the Commission is not required to establish community aggregation procedures until

July 15, 2003.[7] With respect to municipalization, Edison characterizes this trend as "expensive, highly uncertain, and very time consuming." (Edison Reply Comments, p. 10.) Edison notes that should bundled service load decrease as a result of any of these changes, its plan provides for the filing of a revised procurement plan with the Commission.

The Commission has not announced any imminent intention of lifting the current suspension of direct access. In the event the Commission does elect to lift the suspension, such action will occur within the purview of a Commission proceeding and involve public notice in accordance with our Rules of Practice and Procedure. Edison is incorrect in arguing that the Commission has until July 2003 to establish policies and procedures for implementing community aggregation. We note that that the statutory deadline cited by Edison applies to the energy efficiency-related provisions of the bill and not to community aggregation. Local governments may initiate public processes at any time in 2003 to determine whether communities shall participate in community aggregation programs. We also note that prospective aggregators must register with the Commission prior to implementing aggregation.

It is premature at this time to direct the utilities to speculate as to the effects of these possible events in their load forecasts. The utilities should pursue development of new direct access scenarios once it is known with more certainty how community aggregation will be implemented, as well as possible impacts from municipalization and incremental direct access loads. We note that the utilities will be required to file plan updates when certain triggering events occur

[7] The Commission suspended direct access in D.01-09-060 and reaffirmed the September 21, 2001 suspension date in D.02-03-050.

rendering a current procurement plan inaccurate due to changing conditions underlying RNS forecasts (see discussion of plan updates in confidential Appendices A-C).

C. Volume Limits on Procurement

1. Edison

Both ORA and TURN propose downward adjustments to Edison's position limits. ORA states that given the great degree of uncertainty regarding both the size of the 2003 RNS and the distribution of probable future electric market costs, and because customer risk aversion has not yet been measured, the Commission should be conservative and not authorize the utilities to sign excessive amounts of contracts for 2003. It also states that the Commission should keep in mind that, unlike during the energy crisis of 2000-2001, market prices only apply to about 5 to 10 percent of the market, not 100 percent. ORA recommends that the maximum RNS purchase limit be set to a specified percentage of the average hourly RNS for the reference or expected case. For Edison, ORA proposes a modified annual limit for capacity contracts, a modified monthly forward energy contract limit, as well as separate volume limits for gas contracts.

TURN states it is concerned that Edison's plan appears completely focused on ensuring that Edison is not caught short in a period of price volatility while failing to contemplate the possibility of over-procurement and its adverse financial consequences for bundled ratepayers. TURN states that based on its review of the forecasts provided by Edison, the risks associated with potential high market prices (or total dysfunction) appear to be manageable even without locking in any major additional capacity commitments.

As an additional measure to protect ratepayers, TURN proposes that Edison be authorized to procure only 50% of its proposed energy and capacity limits through transactions that do not require pre-approval by the Commission. To the extent that Edison believes that forward purchases of the remaining 50% will benefit ratepayers, it should be required to make a showing as part of a pre-approval process that does not presume reasonableness of the quantities or prices.

We share the concerns of ORA and TURN regarding the prospect that Edison could over-procure energy and capacity. While recognizing that Edison proposes maximum limits that it may not in fact utilize, it is not prudent at this time to pre-approve these ceilings based on a worst-case RNS scenario. We are particularly concerned that Edison could over-hedge its position for a five-year term. This would effectively preclude the Commission's ability to consider renewable procurement under the Renewable Portfolio Standard (RPS), and additional energy efficiency and demand reduction programs for the 2004-2007 period in the long-term planning process. It would also preclude the Commission's ability to ensure that Edison responds in an economically efficient manner to possible reductions in its 2004-2007 RNS from community aggregation and other factors.

Therefore, we adopt ORA's recommendation that Edison establish its monthly forward energy limit based on its Reference Case RNS-Reference Dispatch Scenario, with certain modifications that are specified in confidential Appendix B. We also adopt a modification of TURN's 50% recommendation to address five-year contract limits. We do not find sufficient justification in this record to adopt ORA's recommendations to further limit gas volumes.

2. PG&E

Based on our review and parties' comments, we find PG&E's volumetric guidelines presented in Appendices B and C of its short-term plan are reasonable. We do not find sufficient justification in this record to adopt ORA's recommendations to further limit forward purchases at this time.

3. SDG&E

Based on our review and parties' comments, we find SD&GE's volumetric limits to be reasonable. We do not find sufficient justification to adopt ORA's recommendations to further limit forward purchases at this time. We note that SDG&E's reply comments make the erroneous assumption that ORA's recommendation to limit spot market transactions to a specified percentage of the average hourly RNS is not comparable to the calculation underlying the Commission's guideline in D.02-10-062 that utilities should plan to minimize their spot market exposure to 5% of monthly retail needs.

D. Risk Management

1. Consumer Risk Tolerance Level

In D.02-10-062, we required the utilities to provide a level of consumer risk tolerance, along with a justification for the level they propose, in their November plan updates. We stated we would accept or modify their proposed consumer risk level for the short-term procurement plans and would retain a consultant to gather additional information regarding appropriate consumer risk tolerance levels for use in our review process for 2004.

While PG&E and SDG&E complied with our directive, Edison did not. The proposals by PG&E and SDG&E are well developed but we have concerns, particularly with PG&E's, that the limit it sets is too conservative. By setting too conservative a limit, customers will be paying a higher price premium to hedge against risk.

Both ORA and TURN filed proposals for modifying the utilities' risk management methodologies. TURN's proposal would set a specific consumer risk tolerance level consistently for all utilities. ORA's proposal would take a more conservative approach than that proposed by PG&E for when the utilities would need to meet and confer with PRG to develop a revised hedging strategy and file a revised procurement plan in instances when the price risk exposure of the open position exceeds the consumer risk tolerance level by a specified percentage. We find ORA's proposed trigger mechanism, when used in conjunction with TURN's proposal, to be reasonable and will adopt these two mechanisms for each utility for the short-term procurement plans. Adopting a higher customer risk tolerance also alleviates the concerns expressed by PG&E in Chapter 1, page 1-5 of its short-term plan.

We also adopt PG&E's proposal to revise its language regarding the reasonableness of ISO and bilateral transactions executed while a revised plan is pending approval. In addition, we agree with TURN's comments concerning the procurement selection process as reflected on page C-3 of PG&E's plan. Based on these comments, we direct PG&E to confer with its PRG to elaborate on how it will select among different procurement products to hedge in 2003. PG&E shall file an addendum by Advice Letter to its plan by advice letter providing clarification of this issue at the same time it submits updated tables reflecting executed transitional contracts.

2. Using Value at Risk (VaR), Cash-Flow-at-Risk (CFAR) Models and Other Tools to Measure Portfolio Risk

Each utility proposes its own tools to measure portfolio risk, as discussed in the confidential portion of their procurement plans. ORA recommends that the utilities should move in the direction of analyzing portfolio risk based on a probability distribution of risk drivers in lieu of the utilities' methodologies and specifically recommends the use of VaR and CFAR models.

We agree with ORA that the utilities should move in the direction of analyzing portfolio risk based on a probability distribution of risk drivers but do not want to be prescriptive at this time in requiring use of the VaR and CFAR models. We direct Energy Division to schedule a workshop in early 2003 that will assist us in gathering additional information on this subject and to discuss a broader range of measures of portfolio risk exposure.

We approve PG&E's use of pre-defined scenarios to measure the customers' exposure to specific price and volumetric risks but question the design of its portfolio scenarios, based on ORA's comments. Therefore, we direct it make specific scenario changes, as detailed in confidential Appendix A.

We modify Edison's risk management criteria described in Chapter IV, Section C.1 to include two revisions; similar to the adjustments that were adopted by the Commission recently in Resolution E-3802.

SDG&E's risk assessment methodology is approved without modification; however, we direct SDG&E to meet with its PRG and ORA to discuss further what magnitude is appropriate for a benefit/cost ratio for transaction screening and how it should be calculated.

3. Use of the Black Model and Other Standardized Models

ORA recommends that each utility use the Black Model and a specific benefit/cost ratio for screening transactions. The utilities object to this recommendation and cite to a number of limitations with the Black Model and concerns with the benefit/cost ratio as proposed by ORA.

We do not mandate the use of the Black Model as a determinant for contract evaluation at this time, but do want to have the data collected so that we can better evaluate the model's merits at a later date. Therefore, we direct the utilities to present Black Model results, for informational purposes, as part of their quarterly advice letter filings as well as for contracts submitted for pre-approval.

With respect to prescribing a specific benefit/coat ratio, PG&E and SDG&E shall confer with their respective PRGs to further assess the appropriate magnitude of the benefit-cost ratio and the calculation of such a ratio.

4. Trigger for Plan Updates

TURN proposes that if the monthly RNS deviates from a utility's underlying assumptions by a certain percentage, it should trigger an update of the plan. In each confidential appendix, we set a higher threshold for the trigger and direct that at this level, each utility should confer with its PRG to discuss the need to file a plan update.

E. Renewable Procurement Issues

1. General Comments

In D.02-10-062, we directed the utilities to file, with their November 12th short-term procurement plans, "a report on the status of their procurement under the renewable generation mandate of our previous order (D.02-08-071, directing a 1% incremental renewable procurement." With varying degrees of specificity the utilities have complied, and have subsequently filed – with the exception of Edison – Advice Letters for expedited approval of these new renewable contracts. An evaluation of these short-term plan and Advice Letter filings follows.

Before turning to these filings, however, we wish to address a few outstanding issues raised in the utility filings and in party comments on them. Edison has repeated arguments addressed in D.02-10-062 concerning the relationship between § 701.3, the basis for our 1% incremental procurement order, and the directives of the recently enacted SB 1078. Edison contends in its short-term plan that SB 1078 establishes "additional and qualifying conditions" on this Commission's authority to order renewable set-asides.[8] We disposed of Edison's arguments in D.02-10-062,[9] which cannot be avoided by delay.

Second, parties remain concerned about the exact quantities the utilities are tasked with procuring, and the relationship of past sales levels to the 1% procurement order. The determination of renewable generation "baselines" is a task that will be addressed in party briefs in January, but for now we direct the utilities to submit, as a compliance filing by January 2nd, their 2001 sales figures including DWR power. It is 1% of this figure that utilities are directed to procure in the form of new renewable generation.

Parties express additional concern over the possibility that a utility's baseline renewable generation might shrink, even as the 1 percent procurement is

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[8] Edison short-term plan footnote 5 at p.9.

[9] See D.02-10-062, footnote 14, mimeo. at p. 23.

executed. To this point we provide the following direction: the 1 percent procurement, as has been repeatedly expressed, is to be *incremental* above the existing stock of renewable generation in a utility's portfolio – i.e., above the level of renewable generation the utility sells in 2002. If the utility allows its present renewable generation to shrink by 1 percent, even as it procures 1 percent from another renewable source, it will not be meeting our directive – it will, at best, be holding steady.

To be considered *incremental* renewable generation, the interim procurement must result in a net increase of at least 1% of total 2001 retail sales in the utility's renewable portfolio above its 2002 level. If the 2002 renewable generation baseline amount will shrink in 2003, the utility must procure sufficient renewable power *over and above* this 1% of total 2001 retail sales amount, to result in a total 2003 renewable generation portfolio at least equal to the following: 2002 renewable procurement plus 1% of 2001 retail sales.

This is the imperative, and the measure against which we will be assessing the results of this procurement early next year - when the collaborative CPUC-CEC RPS implementation effort produces, with the assistance of other parties, monitoring and compliance mechanisms that can be deployed. Since the utilities are in the best position to assess the condition of their renewable baseline at present, and have at their disposal a list of potentially cost-effective renewable contracts that can be executed in the coming weeks to insure these conditions are met, we direct the utilities to reaffirm these incremental results immediately. Utilities may find cost-effective procurement options more limited if they wait until next year's verification process to be completed before procuring sufficient renewable power to preserve their baseline. Further contracts filed by Advice Letter for this purpose will be given expedited treatment.

Third, we recognize the outstanding uncertainties regarding the distinctions between existing levels of renewable generation from a given facility, incremental additions to the generation from a given facility, and output from a facility that is completely new. As clarified in D.02-10-062, incremental production from existing facilities *is* eligible to meet the 1% interim procurement target. We must be able to ascertain, however, that this generation is in fact incremental, and for this purpose – and for the purposes of RPS implementation beginning next year – we will rely on the analysis of the CEC. While we have made a preliminary assessment as to whether the approved renewable generation amounts to incremental production, this assessment will not be final until the CEC performs its analysis. As with several other aspects of this renewable procurement effort, we must be flexible as we design the program's parameters, and ask that parties maintain a similar degree of flexibility. Again, the utilities are presently in the best position to answer these questions, and we direct them to avail themselves of all cost-effective options that will achieve the necessary result.

2. Short-Term Plans and Advice Letter Filings

In evaluating the short-term plan filings of each utility in regard to renewable energy procurement, we also discuss the contents of each utility's Advice Letter filing for renewable procurement approval, and the extent to which these two filings together satisfy the requirements of D.02-10-062. As we continue to prepare for implementation of the RPS, we also discuss the effectiveness of the plans in addressing projected needs for future renewable procurement.

As a preliminary matter, we must emphasize that, given the remaining uncertainties regarding baselines, targets and RPS implementation rules, none of the utility plans are sufficiently robust to meet the standard of procurement pre-approval under AB 57. There are simply too many unanswered questions regarding future renewable procurement to allow for further, pre-approved renewable procurement in 2003. However, the RPS implementation process that will unfold next year will develop the standard definitions and contract terms necessary if procurement pre-approval is to be authorized. Moreover, we do not foreclose the option of further renewable procurement by the utilities in 2003, subject to the defined contract filing and approval process. In this aspect of the utility short-term plans we agree with ORA in characterizing these plans as "working documents,"[10] describing the interim RFO process and some preliminary lessons learned, with implications for full RPS implementation to be developed next year.

a) SDG&E

In SDG&E's two-page assessment of its short-term renewable procurement plan, the utility describes what appears to be a commendable RFO process resulting in procurement of substantially more renewable generation than required by our order. SDG&E Advice Letter 1445-E describes more fully the nature of this procurement, estimating that it will result in an incremental 4% of renewable generation in 2003, and approximately 7% in 2004. Commission Resolution E-3803 approved these procurement contracts, and noted the apparently effective participation of the Procurement Review Group in evaluating the solicitation.

[10] ORA Comments on SDG&E November 15, 2002 Procurement Plan, 12/4/02, at p. 4.

CBEA raises several questions regarding SDG&E's solicitation,[11] to which the utility responds in its December 6th Reply Comments. The first concerns the treatment of expiring renewable contracts that SDG&E extended as a result of the interim solicitation, characterized by the utility as "purchases…for incremental megawatts above those that SDG&E would have otherwise made…. Therefore, all of the megawatts associated with the RFO-related renewable contracts are for incremental megawatts and count towards meeting the 1% annual requirement."[12]

This description by SDG&E is overbroad. The procurement requirement in D.02-08-071 is for "at least an *additional* 1 percent of their annual electricity sold" (p. 32, emphasis added). Thus, extending existing contracts serves, all else equal, only to maintain the utility's renewable generation baseline. The 1 percent additional procurement must be met either from projects not currently selling to the utility, or from incremental production from existing facilities. The process for determining incremental output from existing facilities is one that we will turn to early in our RPS implementation process, and cannot be addressed at this time.

As a result we cannot state with certainty the exact amount of new renewable procurement SDG&E has executed, only that we will make this determination next year, once the CEC has developed its certification process in accordance with SB 1078. Nonetheless, we provisionally certify that SDG&E has met its procurement requirement under D.02-08-071, and hold that additional

[11] CBEA Comments, 12/4/02, at pp. 3-4.

[12] SDG&E Reply Comments, 12/6/02, at p. 8.

renewable procurement above the 1 percent incremental requirement will be eligible for satisfaction of procurement requirements under the RPS. If the utility is shown to not have met its 1 percent incremental procurement target, either by under-procurement via the RFO or by allowing its 2001 renewables baseline to shrink, further procurement may be ordered under the authority of § 701.3.

Second, CBEA questions the extent to which SDG&E includes DWR renewable power in the calculation of its baseline and 1 percent targets. SDG&E responds that it did not include such power, given that the contracts allocated to the utility from DWR did not include the so-called "renewable attributes" associated with such power. These renewable contracts, it appears, were therefore excluded from both the baseline and the 1 percent target calculation. While we do not address the issue of renewable attributes here, we intend to investigate these DWR contracts further.[13] In any event, we reiterate our instructions that *all power* sold in 2001 be represented in the calculation of the 1 percent procurement target, including DWR power, and regardless of the technology used to generate it. This DWR power must appear, in effect, in the denominator of the calculation, and we will ensure that it does in the development of our renewable baselines and annual procurement targets. Again, given that SDG&E has apparently procured four times the renewable power

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[13] We also direct the utilities to retain possession of any such attributes (or "green tags") they acquire during this interim solicitation, until appropriate property rights are established by the Commission for these assets. Particularly in instances where Public Goods Charge payments are made to a renewable generator, it may be the case that ownership of such tags should accrue to California ratepayers. As far as maintaining the renewable baseline is concerned, if in fact these renewable attributes are presently owned by an entity other than SDG&E, the associated power should not be included in the baseline calculation.

required of the utility in 2003, we will make a determination on this point when all certification mechanisms are in place.

b) PG&E

PG&E submits a brief discussion of its interim renewable RFO process in its short-term plan, and describes the process and results in its Advice Letter 2303-E. Pending Commission approval of Resolution E-3805, it appears that PG&E has met its 1 percent interim renewable procurement mandate, pending final certification by the CEC of incremental output from existing resources per SB 1078.

A few points require clarification, however, in response to comments from CBEA, TURN and based on our own analysis of the record. First, it appears from tables in Appendix A to PG&E's short-term plan that PG&E calculates its 1 percent target based on anticipated 2003 sales figures, not those from 2001, as directed. As ordered above, we direct the utilities to submit 2001 sales data as a compliance filing by January 2nd, in order that procurement targets can be developed from a common understanding. Again, if this process results in the recalculation of procurement targets for the utility in this interim process, we direct the utility to undertake further renewable procurement as needed. Commission review of these potential new contracts will receive expedited review.

CBEA contends, as it does in SDG&E's case, that PG&E does an inadequate job of ensuring that the utility's renewable generation baseline is calculated correctly and will not shrink in 2003. While we agree with PG&E that it is impossible to predict with certainty the output of many renewable facilities, the requirement is that the utility *contract for* a level of renewable generation that would result in an *additional* 1 percent of generation in 2003. The ultimate output of each facility is a separate matter, and the penalties for deviation from contracted-for levels are determined in each contract. Thus, it is imperative that the interim procurement process results in a *net increase* of at least 1 percent. If the renewables baseline shrinks, new contracts must be signed that will replace the lost power and increase output by at least 1 percent. Since PG&E's proposed renewable procurement level is much lower than that for SDG&E, we cannot assume that, at the margin, our requirement has been satisfied. We will provisionally hold that PG&E has met its interim procurement goal, pending the filing of 2001 sales figures and certification of facility output by the CEC. If the utility is shown to not have met its 1 percent incremental procurement target, either by under-procurement via the RFO or by allowing its 2001 renewables baseline to shrink, further procurement may be ordered under the authority of § 701.3.

TURN raises a number of valid concerns in its confidential comments on PG&E's Advice Letter 2303-E, concerns that merit our attention in analyzing the utility's short-term plan. While we agree with TURN that the concerns raised do not warrant the invalidation of PG&E's interim procurement contracts, we also agree that the issues TURN raises must be addressed fully if the RPS implementation process is to be successful. Rules governing issues such as the eligibility of resources, facility expansion and repowering, and the flexibility of RFO and contract terms will be defined in our implementation process, not by the unilateral declaration of any individual party. We look forward to an effective and mutually beneficial collaboration across all parties as the process develops next year.

c) Edison

Edison provides in its November 12th filing a moderate amount of information regarding targets and assumptions for its 1 percent incremental renewable procurement. One of these assumptions – that the passage of SB 1078 limits the authority of § 701.3 – has been addressed above. Details regarding procurement targets and the RFO process are contained in confidential Volume II of the short-term plan, and what is disclosed looks, on balance, reasonable.

No Advice Letter filing has been forthcoming, however, despite the utility's pledge to file early this month. This delay unfortunately lends credence to the concerns expressed by TURN and CalWEA that Edison is deliberately stalling the interim procurement process, either to test the Commission's § 701.3 authority or to pre-judge the implementation efforts for the RPS program. Examples such as creation of undue barriers to participation by particular technologies, and of price benchmarks different from the Commission's 5.37¢/kWh target, are cited in support of these assertions. Both of these practices, if verified, would constitute violation of Commission orders and would be subject to sanction. The Commission is actively exploring its options in this regard.

Subject to further sanction would be the utility's continued failure to simply file an Advice Letter containing renewable contracts of any sort, be they for more or less than the 1 percent target. Waiting to file will not have the effect of avoiding the requirements of D.02-08-071; in fact it will make those requirements more challenging, as the utility will need to procure the same GWh amount over fewer days in the calendar year.

We find that the utility is in noncompliance with D.02-08-071, and will address this noncompliance in a subsequent Commission order. In the event that this Advice Letter is forthcoming, we reiterate our direction provided to the other utilities regarding calculation of the 1 percent target and the preservation of Edison's baseline level of renewable generation.

d) CBEA

As noted above, CBEA has raised a number of concerns to do with the utilities' interim procurement process, and has described the inability of four biomass plants with expiring DWR contracts to secure contracts under the 1 percent order. CBEA raises three general objections to the utility plans: 1) the plans do not ensure that renewable procurement will increase by 1 percent on net; 2) the plans do not include DWR renewable power in the calculation of the baseline; and 3) utilities may be improperly accounting for existing generation. We have addressed each of these general points above, and have established a verification process for each issue that will result in the quickest possible resolution. CBEA's comments have aided us in assessing the points of contention in the interim procurement process and in the RPS implementation to come.

CBEA's specific complaint, however, is that these four biomass plants were not offered contracts by the utilities and may be forced to close without Commission action. The Commission has approved by Resolution the Advice Letter filings of SDG&E and PG&E, finding that the renewable solicitation process for each utility was sufficiently competitive and has provisionally resulted in sufficient procurement to meet the 1 percent order. To disallow a utility's renewable procurement on the grounds that specific facilities were not acquired, or to force utilities otherwise in compliance with our order to extend contracts to these facilities - particularly given the appearance that these biomass bids were relatively uncompetitive – would be to unduly favor a specific economic interest in this process. At this time we will not force any utility to accept this power. CBEA's remaining avenues for relief, as before, are sales into the open market, a potential short-term contract extension through DWR, or possible registration as a QF under PURPA, for sale directly to the utilities at avoided-cost prices.

3. CPUC-CEC Collaborative Workplan

Pursuant to SB 1078, the CPUC and CEC will collaborate on a number of key RPS implementation points, many of which were identified for party briefs in D.02-10-062. Over the past two months, CPUC and CEC staff have met regularly to scope the RPS implementation issues and develop a plan and schedule for next year's effort. This plan will be informed by party comment on the 6th and 13th of January, and will be served on parties as a Workplan on February 3rd for party comment on February 10th. A portion of the prehearing conference scheduled for February 17th will be set aside for discussion of the plan.

We take this opportunity to clarify our inter-agency approach with the CEC regarding implementation of the RPS. The CEC will designate specific staff members to be RPS Implementation Collaborative Staff, who along with CPUC staff will facilitate the further scoping of RPS issues, management of workshops and hearings, and the production of staff working papers and workshop/hearing reports. CEC RPS Implementation Collaborative Staff will assist decision-makers in both agencies. We will designate a legal framework to allow other members of CEC staff to continue to participate as parties in the Procurement rulemaking on non-RPS issues. The specific parameters of this arrangement will be provided for party comment in the Workplan service of February 3rd. The CEC has agreed that a similar, reciprocal arrangement will be established for CPUC staff in the CEC's rulemaking addressing renewable generation issues.

F. Qualifying Facilities Contracts

CAC states that the utilities' plans are so general in the public version that the Commission should reject the filings as deficient. In addition, CAC states that these plans provide for the procurement of resources for up to a five-year period and during that time several QF contracts will expire. CAC requests that the Commission require the utilities to provide for the renewal of a federally compliant procurement agreement with existing QFs and the maintenance of their output throughout the term of the plan.

In its response, PG&E states the plan is for 2003, not five years, and that the utilities obligations to QFs for 2003 was determined in D.02-08-071. PG&E also points out that the type of material that is designated as protected is covered under the Protective Order in place here.

D.02-10-062 does authorize the utilities to enter five year contracts, but it is only for the purpose of meeting 2003 needs. PG&E is correct that D.02-08-071 addresses QF contracts in 2003. CAC will have the opportunity to address future years in the long-term planning phase.

Turning to CAC's assertion that the plans "lack any meaningful detail," we agree with PG&E that § 454.5(g) requires both the utilities and the Commission to keep market sensitive information confidential. Section 454.5(g) provides in pertinent part that:

> "(g) The commission shall adopt appropriate procedures to ensure the confidentiality of any market sensitive information submitted in an electrical corporation's proposed procurement plan or resulting from or related to its approved procurement plan, . . . provided that the Office of Ratepayer Advocates and other consumer groups that are nonmarket participants shall be provided access to this information under confidentiality procedures authorized by the commission."

Through a combination of nondisclosure agreements, confidential appendices, and acceptance of filings under seals, we have complied with our statutory obligations. We decline at this time to order the utilities to make public more detail regarding their procurement plans. See, on a related note, our disposition of IEP's Motion in Section IV of this decision.

G. Demand Response Programs

ORA raises several important issues in relationship to the integration of utility demand response programs into the short-term procurement plans. Specifically, while ORA finds that the utilities "properly included demand response resources in their short-term procurement plans," ORA requests that the utilities specify which demand response initiatives are treated as resources and which are integrated into the load forecast. ORA also recommends that the utility short-term plans include contracts of one year or less that could be superceded by future demand response efforts.

In addition, ORA present its views on the definition and distinction between: a) tariffs and b) demand response programs. In general, ORA views tariffs as having uncertain impacts in the short-run, but "in the long run as forecast accuracy improves the demand reductions expected in response to the tariff's price signal can be built into the load forecast." On the other hand, ORA views programmatic demand response efforts that are paid for as they are procured as having the potential to be a reliable resource that can be counted on (as supply) to reduce demand when called into play.

The Commission takes note of these comments as well as ORA's recognition that many of the issues addressed in their comments are being considered in our Demand Response Rulemaking (R.02-06-001). Specifically, we note that issues related to the definition of demand response as either supply, or demand response tariffs as less reliable (currently) than supply but valuable as additions to utility load forecasts are currently under consideration in that Rulemaking. Given that this is pending issue in that Rulemaking, the Commission finds it inappropriate at this time to integrate ORA's comments into this current decision.

Without an adequate definition of this issue, and pending a clarification of this issue in R.02-06-001, we find that we cannot at this time require the utilities to make the requested distinction in their short-term plans. Rather, we will be addressing at this issue comprehensively and in a coordinated fashion. We therefore respectfully deny ORA's request on this matter.

H. Reserve Levels

Based on our review and the comments filed, we find the 7% operating reserves level proposed by the utilities in their short-term plans to be adequate for 2003. We have concerns regarding other reserve levels of Edison, and modify its authorized limits in confidential Appendix B.

For the long-term planning phase, ORA requests that each utility provide data sufficient to determine what level of planning reserves would lead to a loss of load probability of one day in ten years, as well as supporting testimony recommending a level of planning reserves. This is a reasonable request and, therefore, we adopt it. We note that ORA's request, while requiring specific data be furnished, allows each utility latitude to propose and support a planning reserve level it considers appropriate to its service territory. This should be done in conjunction with the provisional 15% reserve level and guidance we adopted in D.02-10-062.

I. Cost Recovery and Related Issues

The cost recovery issues were decided by the Commission in D.02-10-062, as discussed in Section XII of that order, and the utilities were directed to implement the necessary accounting mechanisms. In its November 12, filing, PG&E proposes accounting mechanisms not in conformance with D.02-10-062 and raises new arguments regarding the proper implementation of AB 57. We discuss and resolve those issues here.

PG&E included in its plan the cost recovery proposal (Chapter 5) it believes is in compliance with D.02-10-062 and § 454.5(d)(3). On November 13, 2002, PG&E filed Advice Letter 2299-E to implement the procurement ratemaking adopted in D.02-10-062. PG&E's implementation filing, however, includes elements of its cost recovery proposal. The Energy Division rejected the advice letter on November 15, 2002. On November 20, 2002, PG&E met with the Commission General Counsel and representatives from the Energy Division to discuss the rejection of the advice letter and other procurement issues. On November 22, 2002, PG&E filed revised Chapter 5 to clarify ambiguities and modify certain aspects of its cost recovery proposal. The revisions include proposed tariff changes to Transition Revenue Account (TRA) and Emergency Procurement Balancing Account (EPBA) and a pro-forma Preliminary Statement for the Energy Resource Recovery Account (ERRA). PG&E states that the revised Chapter 5 and the attachments supersede the original filing in its entirety. PG&E requests that these tariffs be approved effective January 1, 2003.

1. The Trigger Mechanism and the ERRA Balancing Account

D.02-10-062[14] directs the utilities to file "trigger" applications when undercollections in the ERRA reach 4% "of the electrical corporation's actual recorded generation revenues for the prior calendar year excluding revenues collected for the Department of Water Resources."[15] D.02-10-062 further provides that the a trigger application should call for Commission approval within 60 days of filing. PG&E's cost recovery proposal focuses on language from AB 57/SB 1976 stating "…that any overcollection or undercollection in the power procurement balancing account does not exceed 5 percent of the electrical corporation's of actual recorded generation revenues for the prior calendar year excluding revenues collected for the Department of Water Resources," and so goes beyond the requirements of D.02-10-062 to address contingencies that might occur during the 60-day period when the Commission is reviewing an expedited trigger application filed pursuant to PG&E proposes to include the following items in its trigger application.

1. A projected account ERRA balance in 60 days from the date of the filing and a forecast when the account balance will exceed the 5 percent threshold.
2. Since the ERRA balance cannot exceed 5 percent without triggering rate increases, PG&E proposes to reduce the ERRA balance automatically to the 4 percent threshold by transferring an amount equivalent to the amount that would reduce the balance to this level from the TRA overcollection, if available, in the month the undercollection occurs in the ERRA. Alternatively,

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[14] See D.02-10-062, mimeo. at p. 64.

[15] Pub. Util. Code § 454.5(d)(3).

PG&E will increase rates as follows: (1) if the ERRA balance exceeds 5 percent threshold prior to the end of 60-day period, request an interim emergency rate adjustment; (2) Increase rates on the 61st day of the filing if the Commission does not act on its expedited application and the ERRA balance exceeds 5 percent threshold. This is an automatic rate increase subject to refund and adjustment; and (3) In any month the undercollection in the ERRA exceeds TRA overcollection; PG&E requests a rate increase.

3. In the event of unusual market conditions, PG&E would include in the expedited trigger application updated procurement costs and adjusted revenue requirements to update the stale procurement forecasts. The new forecast would reset the revenue requirement for the rest of the year.

The cost recovery and the ERRA trigger mechanism are intertwined. PG&E, therefore, contends that its cost recovery proposal and the trigger mechanisms it proposed are in compliance with D.02-10-062 and § 454.4(d)(3).

TURN is concerned about PG&E's derivation of the $150 million generation revenue requirement that PG&E suggests is the 5 percent trigger amount in its example of how the transfer from the TRA will be accomplished. TURN alleges that the $150 million is "significantly lower than the comparable number proposed by Edison" and therefore questions whether PG&E included all its 2002-generation revenues, including surcharges in developing the amount.

PG&E responds to TURN's concern that its calculation of the $150 million excludes revenues collected for DWR and claims that it derived its number based on the information contained in Appendix D to D.02-10-062.

PG&E states that it calculated its $150 million based on updated revenue requirement filing[16] pursuant to D.02-04-016.

TURN contends that PG&E's tariff language to transfer the monthly ERRA revenue requirement from the TRA to ERRA and also to transfer the overcollection amount from the TRA to reduce the undercollection in the ERRA to the 4 percent threshold "is simply not what the statute contemplates." Neither TURN nor ORA addresses the issue of automatic rate increases if the Commission fails to act within the 60-day period.

TURN alleges that PG&E's proposed ERRA balancing account preliminary tariff language does not comply with AB 57. TURN adds that the tariff would require substantial revision that should be addressed in an emergency workshop setting conducted by Commission's Energy Division. Specifically, TURN maintains that the statute requires that the balancing account track the difference between actual costs incurred and actual recorded revenues collected to cover those costs. This is in contrast to PG&E's proposed ERRA tariff language, which would track the difference between actual costs incurred and ERRA revenue requirement authorized by the Commission in D.02-04-016, the Utility Retained Generation (URG) decision. In other words, TURN maintains that the ERRA balancing account tariff language should compare actual ERRA costs with the actual generation revenues collected based on the residual generation rate component of the tariff schedules and emergency surcharges which cover not only ERRA costs but allocated DWR costs and non-fuel URG costs.

[16] The Commission's Energy Division approved Advice Letter 2233-E on June 12, 2002.

PG&E argues that TURN's recommendations on the ERRA tariff should be rejected because D.02-10-062 requires that actual recorded procurement costs be tracked against the "recently approved fuel and purchase power revenue requirements" as specified by Appendix D of the decision. PG&E states that the inclusion of generation revenues and surcharge revenues in the ERRA as suggested by TURN would be in violation of D.02-10-062 and AB 57, creating a huge overcollection that could trigger a refund to ratepayers. PG&E further states that costs included in ERRA do not include DWR costs and therefore, revenues recorded in the ERRA should not include DWR revenues which the law specifically excluded from generation revenues. PG&E rejects TURN's suggestion for expedited workshops on the ERRA tariff language and cites ORA's support of its balancing account and trigger mechanism proposal as being reasonable.

2. Starting Point for ERRA Costs and Revenues

PG&E proposes a "starting point" revenue requirement that will be transferred from the TRA to the ERRA to offset ERRA costs. PG&E states that the 2002 URG procurement revenue requirement includes its URG fuel and purchase power costs and not the additional costs to be incurred for the RNS. It proposes to include these additional costs and revenues in the fuel and purchase power revenue requirement adopted in the 2002 URG decision. These costs include open market position, reserves and collateral costs as well as DWR surplus sales revenues allocated to PG&E. PG&E's forecast for these costs and revenues in 2003 produces a negative amount of $3 million. When this amount is added to the fuel and purchase power revenue requirement of $2.038 billion, the proposed starting point revenue requirement is $2.035 billion. PG&E asserts that it made this calculation to avoid a mismatch between revenues and costs, to prevent a triggering event occurring sooner, and for the trigger mechanism to function properly.

PG&E proposes to transfer monthly revenues from the TRA equal to the monthly costs underlying the annual 2003 ERRA starting point revenue requirement or one twelfth of $2.035 billion as ERRA procurement revenue requirement to match against actual costs incurred. TURN opposes this concept as previously discussed.

3. Issues With Proposed Tariff Language

PG&E's Plan's Chapter 5 includes Appendix A, which contains a pro-forma ERRA Preliminary Statement, as well as revised TRA and EPSBA tariffs. PG&E requests approval of the tariffs effective January 1, 2003.

TURN opposes the revised tariff language in the TRA indicating that the tariff "will be in effect until the end of rate freeze." TURN asserts that the language in D.02-11-026[17] shows that the freeze ended no later than March 31, 2002 and therefore, the TRA tariff has expired and should be removed from PG&E's tariffs. PG&E disagrees with TURN. PG&E asserts that "it is premature to supercede its previously Advice Letter[18] filing of post rate freeze accounting mechanisms before a more definitive indication that the Commission is ready to address the effective date of the post rate freeze tariffs."

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[17] Exactly when the freeze ended (e.g., January 18, 2001 with ABX1-6, February 1, 2001 with ABX1-1, or March 31, 2002) will be determined in other proceedings in connection with this rehearing. There is no question, however, that the freeze ended no later than March 31, 2002. (D.02-11-026, footnote 9, p. 14.)

[18] PG&E filed Advice Letter 2057-E to revise electric tariffs in compliance with the end of electric rate freeze. AL 2057-E was rejected by the Commission's Energy Division on December 4, 2000.

TURN also alleges that PG&E's revisions to EPSBA tariff do not comply with D.02-11-026 because PG&E failed to show that it would apply ongoing power costs first to AB 1890 frozen rates and only secondarily to surcharge revenues to the extent needed. In response PG&E states that the same decision requires all utilities to continue to track surcharge revenues in the authorized balancing accounts since they remain subject to later adjustment and possible refund. PG&E states that it revised EPSBA tariff to exclude costs that would be recorded in the ERRA and to keep non-fuel retained generation and DWR costs in the EPSBA.

4. Cost Recovery of Certain Costs

a) Electric Energy Transaction Administration (EETA) Costs

PG&E states that a conflict exists with two Commission decisions as to where EETA costs should be recorded. Appendix D to D.02-10-062 indicates that these costs should be recorded in the ERRA while D.02-09-053 ordered PG&E to address the recovery of EETA costs pertaining to the administration of the DWR contracts allocated to it in the general rate case (GRC). PG&E recommends that these costs be reviewed and set on a forecast basis in the GRC and not recorded in the ERRA. TURN and ORA support PG&E's recommendation.

Edison and SDG&E differ from PG&E's position regarding where and when EETA costs should be recorded and recovered. SDG&E wants to record its EETA costs in the ERRA until base rates are established in its future cost of service application according to its ERRA tariff.[19] Edison agrees with ORA's recommendation to recover ERRA costs through base rate but wants to initially record EETA costs in the ERRA until the effective date of its 2003 Test Year GRC decision. Edison claims that because it does not presently have any RNS costs in Commission authorized rate levels, starting January 1, 2003; it must record its EETA costs and non-EETA costs in the ERRA account.

b) Above-Market Costs Related to Qualifying Facilities (QFs) and Purchase Power Agreements (PPAs)

PG&E asserts that there is some ambiguity regarding where to recover ongoing transition cost component associated with QF and PPA contracts since D.02-11-022 established a market benchmark for determining the above market costs. PG&E recommends that the above-market costs should be recovered in the Modified Transition Cost Balancing Account (MTCBA).

TURN and PG&E differ on how the above market costs or competition transition costs (CTC) should be calculated. PG&E and TURN disagree as to whether the calculation of CTC should be the difference between the average costs of the URG resources or limited to only the QF and PPA costs and the market benchmark.

ORA, Edison and SDG&E agree that all QF and PPA costs should be recorded in the ERRA. Edison further indicates that the CTC portion can be tracked separately in the ERRA.

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[19] SDG&E filed Advice Letter 1451-E in compliance with D.02-10-062 to establish the ERRA.

5. Discussion

a) The Trigger Mechanism and the ERRA Balancing Account

Pub. Util. Code § 454.5(d)(3) provides, in pertinent part, that:

> "The commission shall review the power procurement balancing accounts, not less than semiannually, and shall adjust rates or order refunds, as necessary, to promptly amortize a balancing account, according to a schedule determined by the commission. Until January 1, 2006, the commission shall ensure that any overcollection or undercollection in the power procurement balancing account does not exceed 5 percent of the electrical corporation's actual recorded generation revenues for the prior calendar year excluding revenues collected for the Department of Water Resources. The commission shall determine the schedule for amortizing the overcollection or undercollection in the balancing account to ensure that the 5 percent threshold is not exceeded.

As an initial matter, we must determine how to calculate "5% of the electrical corporation's actual recorded generation revenues . . ." (the "5% threshold"). We share TURN's concern regarding PG&E's derivation of $150 million as the 5% threshold. PG&E's figure is significantly low when compared with Edison's calculation[20] of its (Edison's) 5% threshold. The reason for the discrepancy between Edison and PG&E lies in each utilities' treatment of emergency surcharge revenues. PG&E excludes revenues associated with the emergency surcharges from its "recorded generation revenues" figure, while Edison includes emergency surcharges. Presently, the emergency surcharges of 4.5 cents are part of generation revenues and they should be included in PG&E's

[20] See Edison' Opening Brief dated July 29, 2002, p. 77, footnote 208.

calculation. PG&E must compare actual recorded generation revenue, including the surcharge revenue, in order to calculate whether the threshold has been triggered. Therefore, PG&E is directed to use the same method used by Edison. We expect PG&E's recalculated 5% threshold number to be about $300 million.

We must turn next to the question of how to calculate the level of ERRA over and undercollections. PG&E proposes to track ERRA costs against authorized revenue requirements to determine when to file the expedited 4 percent trigger application. TURN points to language in § 454.5 requiring that actual incurred costs be compared with actual recorded revenues for the determination of over and under collections in the ERRA balancing account. PG&E is correct, however, that D.02-10-062 adopts 2002 URG fuel and purchase power revenue requirements to be tracked against ERRA costs. D.02-10-062 adopts the interim revenue requirements for the majority of costs that will be recorded in the ERRA since the Commission has yet to establish generation rates to recover those costs. We agree with PG&E that the residual generation rate recovers more than fuel and purchase power costs. TURN's request that PG&E be required to use actual incurred costs rather than a revenue requirement to track ERRA under and over collections is denied.

Finally, we turn to the question of what to do when the crossing of the 5% threshold looms. As described above, D.02-10-062 already provides for an expedited trigger application process when undercollections reach the 4 percent level. PG&E, alone among the utilities, is dissatisfied with this approach to undercollections, and as already described proposes several additional ways to avoid crossing the 5% threshold. PG&E seeks authority to automatically transfer overcollection amounts from the TRA to bring the undercollection in the ERRA to the 4 percent level. PG&E has also proposed implementing automatic rate changes requests when the Commission does not act in a timely manner upon an expedited trigger application.

We agree with TURN that the interaction between the TRA and ERRA needs further understanding by the Commission and parties. Also, there are several PG&E's advice letters[21] that are related to TRA mechanism still pending before the Commission.

Nothing in AB 57/SB 1976 requires this Commission to cede its ratemaking authority to PG&E by allowing for automatically effective rate increases (whether subject to refund or not), and we decline PG&E's invitation to do so today. We retain the authority that § 454.5 grants us in determining how to amortize undercollections. That said, we undertake today, in recognition of the somewhat unique posture of PG&E as a bankrupt utility, certain actions to address PG&E's concerns about undercollections exceeding the 5% threshold.

First, we authorize PG&E to file and expedited trigger application at any time that its forecasts indicate it will face an undercollection in excess of the 5% threshold. That is, we no longer require PG&E's ERRA undercollections to reach 4 percent before we will entertain a trigger application.

Second, pending completion of further review of PG&E's ERRA account (about which more below), the Commission commits to act as rapidly as necessary on rate changes requests, consonant with § 454.5's requirement that "[t]he Commission shall… adjust rates or order refunds as necessary, to

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[21] Advice Letter (AL) 2130-E filed June 25, 2001 implementing the adoption what has been termed TURN Accounting. Other advice letters include AL 2096-E that implements the 3 cents surcharge balancing account and AL 2240-E that implements URG balancing accounts and memorandum accounts required by D.02-04-016.

promptly amortize a balancing account, according to a schedule determine by the Commission."

Third, we accelerate our review of PG&E's ERRA account, advancing the review by four months to commence in February rather than in June.[22] We agree with PG&E that it is reasonable to explore the concept of transferring overcollection in a balancing account to offset undercollection in another balancing account. It may not make sense to increase rates because there is undercollection in one account while there is a significant overcollection in another account benefiting the same customers. In order to address PG&E's proposal regarding offsetting ERRA undercollections and to quickly address its concerns, we direct PG&E to file both its forecast application and the balancing account review application on February 1 and August 1, 2003, respectively. SDG&E will file similar applications on June 1 and December 1, 2003. PG&E should include its proposal for applying the overcollection of TRA to the ERRA account in the February filing. We intend to look closely at this approach and also whether refunds to ratepayers should be implemented in the same way.

We take this opportunity to clarify our previous order for SDG&E and Edison. SDG&E should use its generation rate revenues for this purpose instead of the authorized revenue requirements as provided for in its ERRA tariff.[23]

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[22] See D.02-10-062, mimeo. at p. 62.

[23] SDG&E filed its advice Letter 1451-E to implement ERRA tariff on November 20, 2002.

Edison's Advice Letter[24] to implement the ERRA mechanism reflects the tracking of actual incurred ERRA costs against fuel and purchase power revenue requirements without a true-up since it will transfer actual costs recorded in the ERRA to the Settlement Rates Balancing Account (SRBA) in order to determine the amount of Surplus to apply to the Procurement-Related Obligation Account (PROACT). This means that Edison does not plan to file an expedited application when the undercollection in the ERRA tracking sub-account reaches an amount equal to 4 percent of prior year recorded generation revenues excluding revenues collected for DWR because it is recovering its full ERRA costs through the SRBA. We authorize this approach.

Finally, in one further effort to respond to PG&E's concern on timely cost recovery to avoid violating the law, we direct PG&E, SDG&E, and Edison to file with the Commission's Energy Division each month a report showing the activity in the ERRA balancing account with copies of original source document supporting each entry over $100.00 recorded in the account. This report shall be filed not later than the 20th following the end of the month. This should give the Commission the opportunity to anticipate when an expedited trigger application might be filed by any utility. It would also reduce the review time for such application. The report itself, but not the underlying documents, shall be served on interested parties to this proceeding.

In summary, we are making numerous changes to D.02-10-062 to address PG&E's concerns. We deny PG&E's rate adjustment requests and TRA overcollection transfer to the ERRA at this time without prejudice.

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[24] Edison filed Advice Letter 1665-E on November 23, 2002 to implement the ERRA mechanism.

b) Starting Point for ERRA Costs and Revenues

PG&E proposes a $2.035 billion starting point annual revenue requirement for transferring the monthly revenue requirement from the TRA to the ERRA to match against ERRA costs. We tentatively adopt PG&E's calculation of the $2.035 billion as the ERRA revenue requirement for 2003 to be recorded in the account against recorded ERRA costs until parties have the opportunity to review the derivation of the negative $3 million in detail in PG&E's February 1 filing. We deny PG&E's request to transfer one twelfth of this amount from the TRA to the ERRA. Instead, PG&E should debit the equivalent amount credited monthly to the ERRA to the TRA in order to align authorized revenues with actual revenues collected from customers in the TRA. Therefore, PG&E should revise its ERRA and TRA tariffs accordingly.

c) Issues With Proposed Tariff Language

PG&E should revise the language in its TRA tariff when it files its compliance ERRA tariff to implement changes being made to the ERRA mechanism five days after the effective date of this decision to read that: "The TRA will be in effect until the Commission determines the date when rate freeze should have ended." TURN's request is denied.

TURN also questions the revisions to EPSBA tariff. We have reviewed the page cited by TURN in its comments along with D.02-11-026, which is replete with the phrase that the funds from the surcharges should be used "to pay for future power purchases or securing reasonable financial health." We agree with TURN that because of the modification to D.01-03-082, PG&E does not need to track ongoing power costs first with 1-cent surcharge revenues in the EPSBA. Such revenues should be included in the TRA. We note that PG&E currently records the 3 cents surcharge revenues in the TRA as part of the billed revenues because Advice Letter (AL) 2096-E is still pending before the Commission for approval. PG&E should treat the 1-cent surcharge revenues in the same manner as the 3 cents surcharge revenues, they both should be included in the billed revenues in the TRA. PG&E should reduce the total billed revenues including surcharge revenues by revenues collected for DWR to arrive at the residual electric retail revenue available for all authorized costs as required by D.02-02-052 (OP 9), "to segregate DWR related billed revenues from URG related billed revenues." EPSBA should be changed to a memorandum account to track both the 1-cent and 3 cents surcharge revenues included in the TRA billed revenues in a separate sub-account since these are subject to refunds. In view of the changes to D.01-03-082 by D.02-11-026, the tariff changes proposed in the AL 2096-E are moot and the AL should be withdrawn. Other ALs related to AL 2096-E should be amended accordingly five days after the approval of this decision.

d) Cost Recovery of Certain Costs

TURN and PG&E agree that EETA costs should be included in the GRC. SDG&E and Edison want to include the costs in the EERA until such time when base rates are established to recover them. Consistent with D.02-09-053, EETA should be recovered through base rates in the GRC. D.02-10-062 is modified to exclude EETA costs. SDG&E and Edison should modify their ERRA tariffs to exclude costs associated with EETA. Since SDG&E's cost of service application is in the future, SDG&E should track this costs in a memorandum account for later recovery.

PG&E and TURN agree that ongoing transition costs associated with QF and PPA contracts should be recorded in a Modified Transition Cost Balancing Account (MTCBA) for later recovery from all customers. SDG&E and

ORA want to record these costs in the ERRA, which tracks costs incurred by bundled customers. We agree with TURN and PG&E that these costs should not be recorded in the ERRA balancing account. TURN differs with PG&E on how to calculate ongoing CTC associated with QF and PPA contracts in view of the market benchmark established by D.02-11-022.[25] We agree with PG&E's method of CTC calculation, but we also note that those issues will also be more fully addressed in A.00-11-038 et al. (D.02-11-026).

VI. Procedural Process

Edison's updated short-term plan raises the concern that while D.02-10-062 presents requirements for the submittal of quarterly compliance advice letters for transactions entered into in accordance with an approved procurement plan, the decision does not specify dates for by which the Commission will complete its review and resolve any issues. Edison proposes that the Energy Division complete its review of submitted transactions and supporting data within 15 calendar days and that the Commission issue a final decision on the transactions within 45 calendar days after the date Edison submits the data to the Energy Division.

A 15-day review period is too brief, given the Commission's present resources and the fact that there will be three utilities filing these quarterly advice letters. We find that a 30-day day review period for Energy Division is more reasonable. At the conclusion of that period, Energy Division would prepare a resolution within fifteen working days and place it on the next Commission

[25] D.02-11-022 established market benchmark of 4.3 cents.

agenda. These timeframes are guidelines that the Commission will give a top priority.

Edison also notes that the expedited application process outlined in Appendix C to D.02-10-062 for pre-approval of transactions not conforming to a procurement plan does not specify a deadline by which a final Commission decision will be issued. Edison further claims that contrary to § 454.5 (c)(3), the pre-approval process does not indicate whether the Commission would propose alternate transactions that will be deemed reasonable in the event the Commission rejects a contract submitted for pre-approval.

As stated in D.02-10-062, the Commission is committed to an expedited review and it is primarily within the utility's own control as to how quickly the Commission will be able to render a final decision.

Appendix C of D.02-10-062 provides the timelines for Commission consideration if utility's application is uncontested and the criteria set forth in § 311(g)(2) are met, those where at least 30 days public review on and comment on the draft decision is required, and those circumstances where there are issues of substantial controversy or importance to require the scheduling of hearings and the issuance of a proposed decision.

We note that Appendix C to D.02-10-062 explicitly states that during the transitional period, if the Commission rejects a proposed contract as part of the pre-approval process, it will not designate an alternative transaction. Alternative procurement choices will be designated for transactions submitted under these short-term plans.

Edison proposes to file monthly reports with the Energy Division and to serve members of its Procurement Review Group.

VII. PG&E's Petition to Modify D.02-10-062

On November 20, 2002, PG&E filed a petition for modification of D.02-10-062, accompanied by a motion to shorten time for responses. PG&E states that four modifications must be granted concurrently with the approval of its updated plan as it is concerned that it will be unable to perform to the standards proposed in the procurement plan. By ALJ ruling on November 22, the time for responses was shortened to December 3 and the time for PG&E to reply was shortened to December 6, 2002.

Several of the issues PG&E raises are also raised by the other respondent utilities in their updated plan, and some of these issues are also the subject of other petitions to modify. We will address the policy arguments here. The same issues are also before the Commission in several applications for rehearing on D.02-10-024, the legal merits of which will be addressed by the Commission in a later decision.

In its petition, PG&E requests that the Commission remove standards of conduct 4, 6, and 7 found in Section XI of D.02-10-062 at pages 49-51, substantially modify standard of conduct 2, and, further, that D.02-10-062 be modified to provide that Electrical Energy Transaction Administration (EETA) costs be established and approved in PG&E's pending general rate case. The EETA issue is handled in an earlier section of this decision. Following are standards of conduct 2, 4, 6, and 7.

> "2. Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurement process and ensure all employees with knowledge of its procurement strategies sign and later abide by a noncompetitive agreement covering a one year period after leaving utility's employment.

> "4. The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner. Our definitions of prudent contract administration and least cost dispatch is the same as our existing standard.
>
> "6. All contracts must contain substantially the following revision: "in the event of extraordinary circumstances, this contract shall be subject to such changes or modifications by the CPUC as the CPUC may direct.
>
> "7. In order to exercise effective regulatory oversight of the behavior discussed above, all parties to a procurement contract must agree to give the Commission and its staff reasonable access to information within seven working days, unless otherwise practical, regarding compliance with these standards."

PG&E asserts that the standard #2 requirement that employees with knowledge of procurement strategies sign noncompetitive agreements covering a one year period after leaving the utility's employment: 1) may be interpreted as mandating unlawful restrictions on the employment mobility or competitive activities of former employees, in violation of Business and Professions Code § 16600; 2) places such employees on an unequal footing in relation to members of the Procurement Review Group who have equal access to sensitive information but need only sign confidentiality agreements; and 3) limits the utilities' ability to hire the best possible potential employees, who may not wish to constrain their future options by signing such restrictive agreements. PG&E requests that standard #2 be clarified and interpreted only to preclude misuse of trade secrets. PG&E claims it already has a rigorous policy of protecting its trade secrets and that this policy may be enforced longer that the one year period set forth in standard #2.[26]

PG&E asserts that standard #4 above is based upon a misconception of Pub. Util. Code § 454.5(d)(3) - that pre-approved procurement transactions may be reviewed after the fact for "prudence" and "least cost." Further, according to PG&E, this standard exposes the utility to the unwarranted potential risk of disallowances which may endanger its restoration of an investment grade credit rating. It requests this standard be amended to read: "Compliance with an approved procurement plan shall constitute prudent contract administration and least cost dispatch. Additionally we may verify that each contract was administered in accordance with the terms of the contract, and contract disputes which may arise are reasonably resolved."

PG&E states standard #6 is commercially unfeasible because no major energy supplier will sign a contract with such a clause if at all, without imposing an unacceptable premium. PG&E takes a similar view toward standard #7, stating that this requirement would be unacceptable to many suppliers. PG&E requests both standards #6 and #7 be deleted.

In responses to PG&E's petition, the parties filing comments - California Wind Energy Association (CalWea), Center for Energy Efficiency and Renewable Technologies (CEERT), the California Power Authority (CPA), Consumers Union

[26] The Uniform Trade Secrets Act (Civil Code §§ 3426-3426.10) defines "trade secret" as information that "(1) [d]erives independent economic value, actual or potential, from not being generally known to the public or to other persons who can obtain economic value from its disclosure or use; and (2) [i]s the subject of efforts that are reasonable under the circumstances to maintain its secrecy." (Civil Code § 3426.1 (d); see also, *Schlage Lock Company v. Whyte* (2202) 101 Cal. App. 4th 1443 at 1452-1458.)

(CU), Independent Energy Producers (IEP), Sempra Energy Resources (SER), and TURN - all support elimination of standard #6. These parties generally acknowledge the validity of the Commission's concerns but argue that retention of the standard will harm ratepayers because suppliers require certainty in contracts in order to attract capital and make long-term decisions. Because suppliers appear unwilling to accept this provision, these parties contend that it may result in suppressing competition and increasing prices.

For similar reasons, CalWea, CEERT, IEP, and SER also support elimination of standard #7. Parties also state this requirement may require nonjurisdictional entities to give the Commission access to broad areas of information, some of which would be potentially privileged, competitively sensitive data. TURN proposes that the Commission address these concerns by clarifying that the requirement applies only to information demonstrating compliance with the approved behavior standards at the time of contract execution. TURN states that this condition appears limited and reasonable and alleviates the concern of merchant generators that at any time during the course of the contract they would be called upon to provide their latest forward price curves, internal financial statements or other proprietary data.

The only party commenting on PG&E's proposed modification to standard #2 is TURN. TURN supports PG&E's request, stating that extending employee agreements to prohibit certain employment opportunities would be counterproductive, legally problematic and could permanently cripple the pool of expertise available to California's utilities.

The only respondent to address standard #4 is TURN. TURN strongly objects to PG&E's request, stating that PG&E confuses the concept of pre-approval with the continuing obligation to prudently administer contracts consistent with the principles of least-cost dispatch. The practice of least-cost dispatch is critical and must be enforced with respect to every portion of a utility's portfolio. TURN states that PG&E's argument that the Commission does not retain any authority to review the operation and integration of various resources once contract prices and terms are pre-approved is dangerous because it suggests that the Commission has no recourse even if a utility mismanages its resources, drives up costs for ratepayers and rejects any coordinated utilization of various power contracts.

No comments were received supporting PG&E's proposed modification to standard #4. However, in their updated plans Edison, PG&E, and SDG&E each propose language or dollar limits that would substantially alter standard #4.

A. Discussion

In general, the arguments made in PG&E's petition and the responses to the petition are ones that the Commission fully considered in adopting D.02-10-062. PG&E provides additional support for its request to modify standard #2, however, and we do so below. We also remove language and limitations from the utilities procurement plans that are contrary to standard #4 and, at the utilities' request provide a specific definition of the terms least-cost dispatch and prudent contract administration. Because standard #6 is of strong concern to many parties, we modify the clause for the 2003 short-term procurement plans and commit to a full discussion and review of the standard in the long-term procurement phase.

Standard #4 provides for the utilities to prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner. TURN clearly points out the dangers of this Commission agreeing to an interpretation of AB 57/SB 1976 that would remove our continuing oversight of utility operational performance and, thereby, remove the Commission's ability to meet its statutory requirement to assure "just and reasonable" rates.

The utilities have operated their systems under a prudent contract administration and least-cost dispatch standard for many decades and fully understand how to do this. We do not adopt PG&E's proposed standard for dispatch, but instead clarify our previously articulated up-front standard of least-cost dispatch. We believe that this up-front standard provides ample guidance to the utilities, while allowing the Commission to review plan compliance as AB 57/SB 1976 contemplates. We also clarify, to the extent that there was any doubt, that in determining whether utilities have dispatched resources in compliance with their plans' requirements, contract terms or prices will not be at issue.

To provide specific guidance in the procurement plans, we add to each utility's confidential appendix the following language:

> "Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services. PG&E's description of least-cost economic dispatch methodology described in its 1992 "Resource: An encyclopedia of energy utility terms," 2d edition, at pages 152-3 is appropriate with the recognition that a pure economic dispatch of resources may need to be constrained to satisfy operational, physical, legal, regulatory, environmental, and safety considerations. The utility bears the burden of proving compliance with the standard set forth in its plan."

We also adopt a limit for potential disallowances. Although the historical disallowance exhibits prepared by each utility show prudent contract administration and least-cost dispatch were not the cause of significant penalties in the past and we do not expect them to be in the future, we believe that setting an upper limit on disallowances gives utilities and the investment community certainty in estimating the magnitude of potential financial risk, in order to support the utilities' quicker return to creditworthiness. PG&E, in comments associated with the DWR operating agreement draft decision, proposes an annual disallowance exposure of no more than the incremental administrative expense incurred to administer the DWR contracts. We find that this concept can be reasonably applied to the utilities' management of their own resources as well. In addition, we believe that the utilities' exposure should reflect some recognition of their duty to act on behalf of ratepayer interests. Therefore, we will set the maximum disallowance risk exposure at twice the utilities' annual procurement administrative expenditures.

Thus, we set each utility's maximum disallowance risk equal to two times their annual administrative expenses for all procurement functions, including those related to DWR contract administration, utility-retained generation, renewables, QFs, demand-side resources, and any other procurement resources. This limit supercedes, to the extent that it is not consistent with, any provisions of our operating agreement decision, also in this docket. The exact dollar amount for the maximum potential disallowance will be based on their procurement-related administrative expenses, as determined in each utility's general rate case.

Therefore, we do impose dollar limits that change standard #4 as described above. We do not, however, approve the portions of the utilities' procurement plans that change standard #4's requirements through changing our existing review standards or by shifting the burden of proof.

Turning to standard #6, the extraordinary circumstances contract clause. As we explained in D.02-10-024, the Commission intends to exercise this authority only under the most extraordinary circumstances; we would undertake this only after there has been a full opportunity for all affected parties to be heard.

Parties cite concern that with this clause suppliers cannot obtain the necessary long-term financing. This concern is premature as the contracts authorized under the interim procurement plans cannot exceed five years.[27] In the forthcoming long-term planning phase, the Commission will consider all options for new generation and this issue can be readdressed at that time.

CEERT in its response states that since RPS implementation will include defining standard terms, the Commission should not prejudge the issue by requiring standard #6, but rather should leave any final determination of contract terms until after that work has been completed, as the RPS process may result in better ways to offer the protection the Commission seeks through contract terms that will not chill renewable development in the first instance.[28]

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[27] We note the long-term renewable contracts expected to be entered before the next phase are those that were authorized under D.02-08-071 and are not subject to the standards adopted in D.02-10-062.

[28] Several parties reference the Commission's history in removing the regulatory clause from Standard Offer 4 contracts. They fail to cite that the Commission also removed the regulatory clause from procurement contracts in our Biennial Resource Planning Update (BRPU) proceeding. This left the Commission without a valuable tool that could have helped it meet its regulatory responsibilities in several junctures of that proceeding. (For example, this tool would have allowed us to address unanticipated

Footnote continued on next page

The Commission remains committed to retaining the regulatory oversight and jurisdiction necessary to ensure adequate and reliable utility service at just and reasonable rates. However, we recognize the utilities' need to begin procurement within less than two weeks and that they face a marketplace where suppliers are demanding we remove standard #6. Therefore, as an interim measure for the 2003 short-term procurement plans only, we lift the standard for transactions of less than one year and for those 12 months to 60 months, we substitute the following standard #6:

> "For all contracts with terms between 12 and 60 months, all contracts must contain the following revision: "In the event of statutory or federal regulatory changes, this contract shall be subject to such changes or modifications as the CPUC may direct."

The concerns of parties regarding standard #7 are based on a misunderstanding of the requirement. We do not seek unlimited discovery but rather seek only information demonstrating compliance with the approved behavior standards at the time of contract execution.

We now turn to standard #2. Although PG&E somewhat overstates the limitations imposed by the Business and Professions Code, the utility does properly note California's laws and policies favoring employment mobility and restricting the options for employers to limit subsequent employment or competitive activities of former employees. The precise scope of employer options varies with the circumstances. For example, Business and Professions Code § 16601 makes enforceable reasonable noncompetition covenants executed

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bidding strategies from some renewable wind bidders. (See D.94-06-047, 55 CPUC 2d 274).)

by any shareholder of a corporation selling or otherwise disposing of all his or her shares in the corporation. Thus, where a business acquires business interests of individuals who subsequently work for the acquiring business, individuals who disposed of all their shares of the business may enter covenants not to compete with their new employer. Such covenants allow buyers to protect themselves against competition from the seller which would reduce the value of the property right that was acquired. (See, e.g., *Hilb, Rogal and Hamilton Insurance Services of Orange County, Inc. v. Robb* (1995) 33 Cal. App. 4th 1812, 1824-1825.) Similarly, agreements restricting a former employee's employment by a competitor or solicitation of the former employer's customers may be appropriate where necessary to protect trade secrets. (See, e.g., *Muggill v. Reuben H. Donnelly Corp.* (1965) 62 Cal. 2d 239, 242; *Metro Traffic Control, Inc. v. Shadow Traffic Network* (1994) 22 Cal. App. 4th 853, 859; and *Morlife v. Perry* (1997) 56 Cal. App. 4th 1514.)

As a general rule, however, employers may not require employees to sign agreements precluding their subsequent employment by a competitor, or their own independent competitive efforts. (See, e.g., *D'sa v. Playhut, Inc.* (2002) 85 Cal. App. 4th 927; and *Metro Traffic Control, Inc.*, supra, 22 Cal. App. 4th at 859.) Laws prohibiting misappropriation of trade secrets and similar abusive conduct are intended to limit the danger of the misuse of information by former employees. (See, e.g., *Schlage Lock Company v. Whyte* (2002) 101 Cal. App. 4th 1443.) There is "a delicate balance between promoting unfettered competition and protecting businesses from unfair conduct." (*Morlife v. Perry*, supra, 56 Cal. App. 4th at 1519, citing *Continental Car-Na-Var Corp. v. Moseley* (1944) 24 Cal. 2d 104.) Employer options are currently under consideration by the California Supreme Court, which recently granted review in *Advanced Bionics Corporation v. Medtronics, Inc.* (2001) 87 Cal. App.4th 1235 (petition for review granted June 13, 2001: 2001 Daily Journal DAR 6021; 2001 Cal. LEXIS 3764); and *Walia v. Aetna, Incorporated* (2001) 93 Cal. App.4th 1213, not citable, (petition for review granted February 27, 2002: 2002 Daily Journal DAR 2332, 2002 Cal. LEXIS 1306).

Rather than require utilities to dance through the minefield of permissible restrictions on subsequent employment or competition, we will modify standard #2 to more closely focus on the primary concern underlying that standard: our desire to ensure that former employees do not misuse confidential trade secrets and other information acquired during employment with the utility to the utility's subsequent detriment. Standard #2 will now read as follows:

> "2. Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurement process that: 1) identifies trade secrets and other confidential information; 2) specifies procedures for ensuring that such information retains its trade secret and/or confidential status [e.g., limiting access to such information to individuals with a need to know, limiting locations at which such information may be accessed, etc.]; 3) discusses employee actions that may inadvertently waive or jeopardize trade secret and other privileges; 4) discusses employee or former employee activities that may involve misappropriation of trade secrets or other confidential information, unlawful solicitation of former clients or customers of the utility, or otherwise constitute unlawful conduct; 5) requires or encourages negotiation of covenants not to compete to the extent such covenants are lawful under the circumstances [e.g., where a business acquires business interests of individuals who subsequently work for the acquiring business, the individuals disposing of their business interests may enter covenants not to compete with their new employer.] All employees with knowledge of its procurement strategies should be required to sign and abide by an agreement to comply with the comprehensive code of conduct and to

> refrain from disclosing, misappropriating, or utilizing the utility's trade secrets and other confidential information during or subsequent to their employment by the utility."

VIII. Waiver of Comments by the Commission on Draft Decision

Pursuant to Rule 77.7(f)((9) of the Commission's Rules of Practice and Procedure, we determine that the public necessity requires waiver of the 30-day period for public review and comment. The respondent utilities filed updated procurement plans on November 12 and November 15, 2002. PG&E also filed a supplement to its plan on November 22, 2002. Interested parties filed comments on December 4 and 5, and utilities served their responses electronically after 5:00 p.m. on December 6, 2002.

Public necessity requires the waiver of the 30-day period for public review and comment because failure to adopt a final decision by the Commission's December 19, 2002 agenda meeting would place at risk our requirement that the respondent utilities resume full procurement activities on January 1, 2003 in keeping with the expiration of the authority of DWR under AB1X to enter new contracts after December 31, 2002. Thus, failure of the Commission to act by December 19, 2002 could endanger the public's health and welfare, and this clearly outweighs the public interest in allowing a comment-and-review period.

Commission Waiver of Comment Period for Alternate Pages

Pursuant to Rule 77.7(f) and Rule 81 (f) and (g) of the Commission's Rules of Practice and Procedure, we determine that an unforeseen emergency situation requires waiver of the 30-day period for public review and comment on alternate pages. The respondent utilities filed modified procurement plans in conformance with D.02-10-062 on November 12 and November 15, 2002. PG&E also filed a supplement to its plan on November 22, 2002. Interested parties filed comments on December 4 and 5, and utilities served their responses electronically after 5:00 p.m. on December 6, 2002.

Rule 81 provides in pertinent part that "'unforeseen emergency situation' means a matter that requires action or a decision by the Commission more quickly than would be permitted if advance publication were made… Examples include … (f) Requests for relief based on extraordinary conditions in which time is of the essence…(g) Deadlines for Commission action imposed by legislative bodies…" An unforeseen emergency situation requires the waiver of the 30-day period for public review and comment. Failure to adopt a final decision by the Commission's December 19, 2002 agenda meeting would place at risk our satisfaction of a statutory mandate that the respondent utilities resume full procurement activities on January 1, 2003. See Assembly Bill 57, Section 1(b), which states a legislative intent to: "[e]nsure, by no later than January 1, 2003, that each electrical corporation whose customers are currently being served by the Department of Water Resources will resume procurement for those needs that are not being met by the Department of Water Resources." The authority of DWR under AB1X to enter new contracts ends on and after January 1, 2002. See Water Code § 80260. This is a deadline imposed by the legislature on this commission, as described in Rule 81 (g). In addition, as described in Rule 81(f), time is of the essence and failure to act by December 19, 2002 could jeopardize PG&E's request in bankruptcy court to resume full procurement activities on January 1, 2003. Finally, failure of the Commission to act by December 19, 2002 could endanger the public's health and welfare. For these reasons, we waive public review and comment.

IX. Assignment of Proceeding

Loretta M. Lynch is the Assigned Commissioner and Christine M. Walwyn is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Both the Commission and the legislature have clearly expressed their intent to return the respondent utilities to full procurement on January 1, 2003, consistent with the utilities' statutory obligation to serve their customers and the provisions of Assembly Bill ABX1 X.

2. Our approval of the updated procurement plans, as modified by each utility's adopted confidential appendix, puts in place the upfront standards and practices under which each utility shall conduct its procurement. Any adjustments or revisions that are requested by the utilities or other parties will be considered only on a prospective basis.

3. We have identified and addressed conflicts between the DWR/utility servicing agreements and operating agreements in the confidential appendices.

4. The confidential appendices list the specific modifications this decision adopts to the November procurement plans filed by the utilities.

5. The Commission realizes that the transparent competitive market may not be robust but we do expect the up-front standard for bilateral contracts to be met by a strong showing. This could be met, for example, by comparison to Requests for Proposals completed within one month of the transaction.

6. We encourage the utilities to pursue the option of inter-utility exchanges. If the utilities find our adopted cost effectiveness standard has problems in today's market environment, they should confer with their procurement review group and propose an alternative.

7. Utility procurement of early 2004 needs should not await a final Commission decision on long-term procurement plans, although we recognize that a final decision on such plans is scheduled for November 2003.

8. PG&E’s, Edison’s, and SDG&E’s forecast of their loads and resources assumptions underlying the forecast residual net short in their procurement plans are reasonable.

9. The utilities should pursue development of new direct access scenarios once it is known with more certainty how community aggregation will be implemented as well as possible impacts from municipalization and incremental direct access loads.

10. While recognizing that Edison proposes maximum volume limits on transactions that it may not in fact utilize, it is not prudent at this time to pre-approve these ceilings. We are particularly concerned that Edison could over-hedge its position for a five-year period.

11. It is reasonable to adopt the recommendation that Edison establish its monthly forward energy limit based on its reference case RNS-Reference Dispatch Scenario, with certain modifications that are specified in confidential Appendix B.

12. We do not find sufficient justification in this record to adopt ORA’s recommendations to further limit Edison’s gas volumes, forward energy and forward capacity amounts at this time.

13. We find PG&E’s volumetric guidelines presented in Appendices B and C of its short-term plan are reasonable.

14. We do not find sufficient justification in this record to adopt ORA’s recommendations to further limit forward purchases for PG&E at this time.

15. We find SDG&E’s volumetric limits to be reasonable.

16. We do not find sufficient justification in this record to adopt ORA's recommendations to further limit forward purchases for SDG&E at this time.

17. We note that SDG&E's reply comments make the erroneous assumption that ORA's recommendation to limit spot market transactions to 4% of the hourly average RNS is comparable to the calculation underlying the Commission's guideline in D.02-10-062 that utilities should plan to minimize their spot market exposure to 5% of monthly needs.

18. Edison did not comply with the Commission's directive in D.02-10-062 to present a consumer risk tolerance level.

19. In setting a consumer risk tolerance level, we find ORA's proposed trigger mechanism, when used in conjunction with TURN's proposal to be reasonable and, therefore, should adopt these two mechanisms for each utility for their short-term procurement plans.

20. The utilities should move in the direction of analyzing portfolio risk based on a probability distribution of risk drivers.

21. PG&E should make specific portfolio risk scenario changes as detailed in confidential Appendix A.

22. We cannot state with certainty the exact amount of new renewable procurement SDG&E has executed, only that we will make this determination next year, once the CEC has developed its certification process in accordance with SB 1078.

23. Pursuant to SB 1078, the Commission and CEC will collaborate on a number of key Renewable Portfolio Standard implementation points, many of which were identified for party briefs in D.02-10-062. The specific parameters of this arrangement will be provided for party comment in a workplan filed on February 3, 2003 for comment by February 10, 2003. A portion of the prehearing

conference scheduled for February 17, 2003 in D.02-10-062 will be set aside for discussion of the workplan.

24. Under our inter-agency approach with the CEC regarding implementation of the Renewable Portfolio Standard, the CEC will designate specific staff members to be RPS Implementation Collaborative Staff, who along with Commission staff will facilitate the further scoping of RPS issues, management of workshops and hearings, and the production of staff working papers and workshop / hearing reports. CEC RPS Implementation Collaborative Staff will assist decision makers in both agencies. We will designate a legal framework to allow other members of CEC staff to continue to participate as parties in the Procurement rulemaking on non-RPS issues. The specific parameters of this arrangement will be provided for party comment in the workplan.

25. The CEC has agreed that a similar, reciprocal arrangement will be established for Commission staff in the CEC's rulemaking addressing renewable generation issues.

26. Issues related to the definition of demand response as either supply, or demand response tariffs as less reliable (currently) than supply but valuable as additions to utility load forecasts, are currently under consideration in Rulemaking R.02-06-001 and, therefore, it is inappropriate at this time to integrate ORA's comments on demand response into this decision.

27. Without an adequate definition of demand response initiatives, and pending a clarification of this issue in R.02-06-001, we find that we cannot at this time require the utilities to make the requested distinction in their short-term procurement plans.

28. The 7% operating reserves proposed by the utilities in their plans are adequate for 2003. We have concerns regarding other reserve levels of Edison, and should modify its authorized limits in confidential Appendix B.

29. ORA's request that each utility in the long-term planning phase provide data sufficient to determine what level of planning reserves would lead to a loss of load probability of one day in ten years, as well as supporting testimony recommending a level of planning reserves, is reasonable.

30. The Commission should develop a further understanding of the interaction between PG&E's Transition Revenue Account (TRA) and Energy Resource Recovery Account (ERRA) accounts.

31. There are several PG&E advice letters that are related to the TRA mechanism still pending before the Commission.

32. In recognition of the somewhat unique posture of PG&E as a bankrupt utility, it is reasonable for the Commission to undertake certain actions to address its concerns about undercollections exceeding the 5% threshold.

33. It is reasonable to explore PG&E's concept of transferring overcollection in a balancing account to offset undercollection in another balancing account.

34. The Commission intends to look closely at PG&E's accounting approach and also whether refunds to ratepayers should be implemented in the same way.

35. Because of our modification to D.01-03-082, PG&E does not need to track ongoing power costs first with the 1-cent surcharge revenues in the Emergency Procurement Balancing Account (EPBA). Such revenues should be included in the TRA.

36. PG&E currently records the 3 cents surcharge revenues in the TRA as part of the billed revenues because Advice Letter 2096-E is still pending before the Commission for approval.

37. PG&E should treat the 1-cent surcharge revenues in the same manner as the 3 cents surcharge revenues, they both should be included in the billed revenues in the TRA.

38. PG&E should reduce the total billed revenues including surcharge revenues by revenues collected for DWR to arrive at the residual electric retail revenue available for all authorized costs as required by D.02-02-052 (Ordering Paragraph 9), "to segregate DWR related billed revenues from Utility Retained Generation (URG) related billed revenues."

39. PG&E's Emergency Procurement Surcharge Balancing Account (EPSBA) should be changed to a memorandum account to track both the 1-cent and 3 cents surcharge revenues included in the TRA billed revenues in a separate sub-account since these are subject to refunds.

40. Ongoing transition costs associated with Qualifying Facilities (QF) and Purchased Power Agreements (PPA) contracts should be recorded in a Modified Transition Cost Balancing Account (MTCBA) for later recovery from all customers, not in the ERRA balancing account.

41. We agree with PG&E's method of calculating ongoing Competitive Transition Costs (CTC) associated with QF and PPA contracts, but we also note that these issues will be more fully addressed in A.0-11-038 *et. al.* (D.02-11-026).

42. After the transitional procurement period, when the Commission rejects a proposed contract as part of the procurement pre-approval process, it will designate an alternative transaction.

43. Edison's proposal to file monthly reports on its hedging position is reasonable.

44. To provide certainty to the utilities and the investment community, it is reasonable to adopt a maximum amount of potential disallowance to the utility

for violation of standard of behavior #4 in D.02-10-062 based on their annual administrative expenditures associated with all procurement activities.

Conclusions of Law

1. Vulcan Power's October 15, 2002 motion to intervene is granted.

2. IEP's November 26, 2002 motion is denied.

3. CAC's December 13, 2002 motion to receive comments and PG&E's December 13, 2002 motion for late-filed reply comments are granted.

4. With the incorporation of the additions, deletions, and modifications set forth in each confidential appendix into the November 2002 filed procurement plans, we adopt a revised updated procurement plan for each utility that meets the statutory requirements of Senate Bill 1976 and all other provisions of the California Public Utilities Code.

5. The legal interpretation of AB 57/SB 1976 is found in the Commission's decisions and the procurement plans must be in compliance with that interpretation.

6. Nothing in the approved procurement plans should be contrary to the procedures adopted in the DWR/utility servicing agreements and operating agreements and the underlying decisions adopting those agreements. To the extent any material in the procurement plans filed by the respondent utilities is contrary to the referenced agreements and decisions, those sections are not approved here.

7. Prospective community aggregation program aggregators must register with the Commission prior to implementing aggregation.

8. We should adopt a modification of TURN's 50% recommendation for Edison to address five-year contract limits.

9. We should adopt PG&E's proposal to revise its language regarding the reasonableness of ISO and bilateral transactions executed while a revised plan is pending approval.

10. We should adopt TURN's comments concerning the procurement selection process as reflected on page C-3 of PG&E's plan. We should direct PG&E to confer with its procurement review group to elaborate on how it will select among different procurement products to hedge in 2003.

11. Our directive in D.02-10-062 that utilities procure 1% of their 2001 sales figures including DWR power in the form of new renewable generation should be incremental above the existing stock of renewable generation in a utility's portfolio - *i.e.* above the level of renewable generation the utility sells in 2002.

12. We should make a preliminary finding here that PG&E and SDG&E have met the transitional procurement requirement of D.02-08-053 for renewable resources but rely on the California Energy Commission analysis of whether production from an existing renewable facility qualifies as an incremental addition for a final determination.

13. None of the utilities' plans are sufficiently robust to meet the standard of procurement pre-approval under SB 1976 / AB 57. However, we should not foreclose the option of further renewable procurement by the utilities in 2003, subject to the defined contract filing and approval process.

14. We provisionally certify that SDG&E has met its procurement requirement under D.02-08-071, and hold that additional renewable procurement above the 1 percent incremental requirement will be eligible for satisfaction of procurement requirements under the Renewable Portfolio Standard.

15. If SDG&E or PG&E is shown to not have met its 1 percent incremental procurement target, further procurement may be ordered under the authority of Public Utilities Code Section 701.3.

16. We provisionally certify that PG&E has met its 1 percent interim renewable procurement mandate, pending its filing of 2001 sales figures and final certification by the CEC of incremental output from existing resources per SB 1078.

17. Edison is in noncompliance with D.02-08-071's directive on renewable resource procurement and the Commission should address this noncompliance in a subsequent order.

18. We should not grant CBEA's request to grant contracts to the four biomass plants not offered contracts by the utilities.

19. We should decline at this time to order the utilities to make public more detail regarding their procurement plans.

20. We should deny TURN's request that PG&E be required to use actual incurred costs rather than a revenue requirement to track ERRA under and over collections.

21. Nothing in AB57 / SB1976 requires this Commission to cede its ratemaking authority to PG&E by allowing for automatically effective rate increases (whether subject to refund or not).

22. The Commission retains the authority that Pub. Util. Code § 454.5 grants us in determining how to amortize undercollections.

23. We should authorize PG&E to file an expedited trigger application at any time that its forecasts indicate it will face an undercollection in excess of the 5% threshold.

24. Pending completion of further review of PG&E's ERRA account, the Commission should commit to act as rapidly as necessary on rate change requests, consonant with Pub. Util. Code § 454.5's requirement that "(t)he Commission shall…adjust rates or order refunds as necessary, to promptly amortize a balancing account, according to a schedule determined by the Commission."

25. We should accelerate our review of PG&E's ERRA account, advancing the review by four months to commence in February rather than in June.

26. We clarify our previous order on ERRA accounting for SDG&E and Edison. SDG&E should use its generation rate revenues for ERRA instead of the authorized revenue requirements as provided for in its ERRA tariff. We should authorize Edison to implement the ERRA mechanism by tracking of actual incurred ERRA costs against fuel and purchase power revenue requirements without a true-up since it will transfer actual costs recorded in the ERRA to the Settlement Rates Balancing Account (SRBA) in order to determine the amount of Surplus to apply to the Procurement-Related Obligation Account (PROACT).

27. We should tentatively adopt PG&E's calculation of the $2.035 billion as the ERRA revenue requirement for 2003 to be recorded in the account against recorded ERRA costs until parties have the opportunity to review the derivation of the negative $3 million in detail in PG&E's February 1st filing.

28. We should deny PG&E's request to transfer one twelfth of this amount from the TRA to the ERRA. Instead, PG&E should debit the equivalent amount credited monthly to the ERRA to the TRA in order to align authorized revenues with actual revenues collected from customers in the TRA.

29. In view of the changes to D.01-03-082 by D.02-11-026, the tariff changes proposed by PG&E in Advice Letter 2096-E are moot and the advice letter should be withdrawn.

30. Consistent with D.02-09-053, Electric Energy Transaction Administration (EETA) costs should be recovered through base rates in the general rate case proceedings. SDG&E and Edison should modify their ERRA tariffs to exclude costs associated with ETTA. Since SDG&E's cost of service application is in the future, SDG&E should track these costs in a memorandum account for later recovery.

31. We should set a maximum risk of potential disallowance for each utility at twice their annual expenditures on all procurement activities, as established in their general rate cases.

32. We should not approve the portions of the utilities' procurement plans that change standard of behavior #4's requirement, as adopted in D.02-10-062, either through changing our existing standards or by shifting the burden of proof.

33. Pursuant to Rule 77.7(f)(9), we find that public necessity requires the waiver of the 30-day period for public review and comment on this draft decision because failure of the Commission to act by December 19, 2002 could endanger the public's health and welfare, and this clearly outweighs the public interest in allowing a comment-and-review period.

34. Pursuant to Rule 81(f) and (g), we determine that an unforeseen emergency situation requires waiver of the 30-day period for public review and comment on alternate pages.

INTERIM ORDER

IT IS ORDERED that:

1. PG&E's updated procurement plan is modified to reflect the changes contained in confidential Appendix A. Edison's updated procurement plan is modified to reflect the changes contained in confidential Appendix B. SDG&E's updated procurement plan is modified to reflect the changes contained in confidential Appendix C.

2. The confidential appendices are filed under seal and are subject to the May 1, 2002 protective order governing access to and the use of all protected materials in this proceeding. The utilities are not authorized access to each others' appendices. Each respondent utility should obtain a copy of its individual appendix from Interim Chief Administrative Law Judge Carol Brown, or her designee, and is responsible for providing copies to all individuals authorized to receive this material within 5 days. The attorneys for ORA and TURN may obtain copies of all appendices directly from ALJ Brown or her designee.

3. PG&E, Edison, and SDG&E are directed to begin transacting immediately, in accordance with the modified procurement plans adopted herein, for procurement needs in January 2003.

4. To address the new proposals and material that is not in compliance with D.02-10-024, we adopt a confidential appendix for each utility that sets forth the manner in which its November updated procurement plan is modified.

5. Each respondent utility is authorized to hedge 2004 first quarter residual net short/long positions with transactions entered into in 2003. Each utility shall consult with its respective Procurement Review Group in the development of a hedging strategy for 2004 first quarter needs.

6. In order that the short-term procurement plans accurately reflect the final disposition of transitional contracts approved by the Commission under the procurement authority granted in D.02-08-071, PG&E and Edison shall update their plans within 18 calendar days of the effective date of this decision.

7. PG&E shall file by advice letter an addendum to its plan providing clarification on how it will select among different procurement products to hedge in 2003 at the same time it submits updated tables reflecting executed transitional contracts.

8. Energy Division shall schedule a workshop in February 2003 that will assist the Commission in gathering information on Value at Risk and Cash-Flow at Risk models and to discuss a broader range of measures of portfolio risk exposure.

9. SDG&E shall meet with its PRG and ORA to discuss further what magnitude is appropriate for a benefit / cost ratio and how it should be calculated.

10. The utilities shall present Black Model results, for informational purposes, as part of their quarterly advice letter filings as well as for contracts submitted for pre-approval.

11. At the trigger threshold level set in the confidential appendices, each utility shall confer with its procurement review group to discuss the need to file a plan update.

12. Each utility shall submit by January 2, 2003 by compliance filing its 2001 sales figures including Department of Water Resources power.

13. If the 2002 renewable generation baseline amount shrinks in 2003 for a respondent utility, it shall procure sufficient renewable power over and above this 1% of total 2001 retail sales amount, to result in a total 2003 renewable generation portfolio at least equal to the following: 2002 renewable procurement

plus 1% of 2001 retail sales. We direct the utilities to reaffirm their incremental results immediately.

14. For the long-term planning phase, each utility shall provide ORA data sufficient to determine what level of planning reserves would lead to a loss of load probability of one day in ten years.

15. PG&E shall use the same method as used by Edison in calculating when the threshold has been triggered for the ERRA Balancing Account.

16. PG&E shall file both its forecast application and the ERRA balancing account review application on February 1 and August 1, 2003, respectively.

17. SDG&E shall file similar applications on June 1 and December 1, 2003.

18. PG&E shall include its proposal for applying the overcollection of TRA to the ERRA account in the February filing.

19. PG&E, SDG&E, and Edison shall file with the Energy Division each month a report showing the activity in the ERRA balancing account with copies of original source documents supporting each entry over $100.00 recorded in the account. This report shall be filed not later than the 20th day following the end of the month. The report itself, but not the underlying documents, shall be served on all interested parties in this proceeding.

20. We deny PG&E's rate adjustment requests and TRA overcollection transfer to the ERRA at this time without prejudice.

21. PG&E shall revise its ERRA and TRA to conform to this order.

22. PG&E shall revise the language in its TRA tariff when it files its compliance ERRA tariff to implement changes being made to the ERRA mechanism five days after the effective date of this decision to read that: "The TRA will be in effect until the Commission determines the date when the rate freeze should have ended."

23. PG&E shall amend other advice letters related to AL 2096-E within five days after the approval of this decision.

24. PG&E's November 20, 2002 Petition to Modify Decision (D.) 02-10-062 is granted in part to provide:

a. Electrical Energy Transaction Administration (EETA) cost shall be established and approved in PG&E's general rate case; and

b. The standards of behavior 2, 4, and 6 in Section XI are clarified and modified as follows:

"2. Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurement process that: 1) identifies trade secrets and other confidential information; 2) specifies procedures for ensuring that such information retains its trade secret and/or confidential status [e.g., limiting access to such information to individuals with a need to know, limiting locations at which such information may be accessed, etc.]; 3) discusses employee actions that may inadvertently waive or jeopardize trade secret and other privileges; 4) discusses employee or former employee activities that may involve misappropriation of trade secrets or other confidential information, unlawful solicitation of former clients or customers of the utility, or otherwise constitute unlawful conduct; 5) requires or encourages negotiation of covenants not to compete to the extent such covenants are lawful under the circumstances [e.g., where a business acquires business interests of individuals who subsequently work for the acquiring business, the individuals disposing of their business interests may enter covenants not to compete with their new employer.] All employees with knowledge of its procurement strategies should be required to sign and abide by an agreement to comply with the comprehensive code of conduct and to refrain from disclosing, misappropriating, or utilizing the utility's trade secrets and other confidential information during or subsequent to their employment by the utility."

For standard #4, to provide specific guidance in the procurement plans, we add the following language:

> "Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services. PG&E's description of least-cost economic dispatch methodology described in its 1992 "Resource: An encyclopedia of energy utility terms," 2d edition, at pages 152-3 is appropriate with the recognition that a pure economic dispatch of resources may need to be constrained to satisfy operational, physical, legal, regulatory, environmental, and safety considerations. The utility bears the burden of proving compliance with the standard set forth in its plan."

For standard #6, as an interim measure for the 2003 short-term procurement plans only, we lift the standard for transactions of less than one year and for those 12 months to 60 months, we substitute the following standard #6:

> "For all contracts with terms between 12 and 60 months, all contracts must contain the following revision: "In the event of statutory or federal regulatory changes, this contract shall be subject to such changes or modifications as the CPUC may direct."

25. We set an annual maximum potential disallowance for violation of standard #4 at twice each utility's annual expenditures on all procurement activities. Setting this maximum amount supercedes, to the extent that it is not

consistent with, any decision on DWR and utility operating agreements or orders issued in this docket.

26. In all other matters, PG&E's Petition to Modify D.02-10-062 is denied.

This order is effective today.

Dated December 19, 2002, at San Francisco, California.

LORETTA M. LYNCH
President
HENRY M. DUQUE
CARL W. WOOD
GEOFFREY F. BROWN
MICHAEL R. PEEVEY
Commissioners