STATE OF CALIFORNIA GRAY DAVIS, *Governor*

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

October 10, 2002

Agenda ID# 1243
Alternate Order to ID#1146
For 10/24/02 Agenda Mtng

TO: PARTIES OF RECORD IN R.01-10-024

Enclosed is the proposed alternate decision of Commissioner Peevey. It will be on the Commission's agenda on October 24, 2002, along with the proposed decision of Administrative Law Judge (ALJ) Walwyn. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decisions, it may adopt all or part of them as written, amend or modify them, or set them aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

As set forth in Rule 77.6, parties to the proceeding may file comments on the enclosed alternate order no later than October 17, 2002. An original and four copies of the comments with a certificate of service shall be filed with the Commission's Docket Office and copies shall be served on all parties on the same day of filing. Anyone filing comments shall electronically serve those on the service list who have provided electronic addresses. Parties shall also ensure that they electronically serve their comments on Commissioner Peevey's energy advisor, Julie Fitch, at jf2@cpuc.ca.gov and the assigned ALJ Walwyn, at cmw@cpuc.ca.gov. For those who have not provided electronic addresses, printed copies of the comments shall be served by first class mail or other expeditious mode of delivery. Reply comments may also be filed no later than October 21, 2002.

/s/ Carol Brown (by psw)
Carol Brown, Interim Chief
Administrative Law Judge

jf2:acb

Attachment

Decision **ALTERNATE PROPOSED DECISION OF COMR. PEEVEY**
(Mailed 10/10/2002)

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

(See Appendix A for List of Appearances)

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INTERIM OPINION

I. Summary

This decision adopts the regulatory framework under which Southern California Edison Company (Edison), Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall resume full procurement responsibilities on January 1, 2003. The framework we adopt contains requirements for utility procurement plans, expedited review procedures, and timely cost recovery mechanisms that conform to Assembly Bill (AB) 57's statutory requirements.[1]

The energy crisis of 2000 and 2001 has changed the regulatory landscape in a profound way for utilities, their customers, their creditors, and regulators. The means by which we fulfill our mandate to ensure just and reasonable rates and reliable service is not straightforward or simple in today's energy markets. We need to give the utilities flexibility to be creative in transacting for energy to meet their obligation to serve their customers so that the utilities can take advantage of market opportunities that result in the lowest stable prices to customers. At the same time, the utilities request we provide assurance of more timely regulatory review and cost recovery.

We meet the above objectives proactively, by setting up a procurement planning and implementation framework. By regularly revisiting and updating the utilities' procurement plans, we will incorporate the knowledge we gain when the utilities resume procurement on January 1, 2003 into the adopted

[1] AB 57 was passed by the Senate on June 28, 2002 and unanimously by the Assembly on July 3, 2002. It was signed by Governor Davis on September 24, 2002.

procurement plans, making the plans the working blueprints envisioned by the legislature in AB 57.

We find the procurement plans filed on May 1, 2002 need to be updated prior to January 1, 2003, to reflect the allocation of existing California Department of Water Resources (DWR) contracts and any procurement done under the transitional authority we granted in Decision (D.) 02-08-071.[2] Therefore, we direct the utilities to file short-term procurement plans (for 2003) on November 12, 2002, provide an opportunity for all interested parties to file written comments, and anticipate a draft decision for the Commission's consideration at our December 19, 2002 meeting.

We also provide a great deal of detail in this decision on the direction the utilities should take in their long-term procurement planning, and require that they file their long-term plans on February 15, 2003. In particular, we require the utilities' long-term plans to include a mix of resources including conventional generation, distributed generation, demand-side resources, transmission and a reserve requirement.

In this decision, we also reiterate our commitment to developing California's renewable generation stock, and take several steps to promote renewables in the near term and in pursuit of the new Renewable Portfolio Standard (RPS) program. We will ensure that the respondent utilities follow our directive to procure 1% incremental renewable energy in partnership with DWR,

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[2] At hearing on July 2, 2002, Edison, ORA, PG&E, and SDG&E stated that while an update filing before January 1, 2003 is necessary, the plans before us now meet the 90-day requirement of proposed Section 454.5(a). SB 1976, also signed by Governor Davis on September 24, 2002, changes the 90-day requirement to 60 days.

and note that this directive was given prior to the passage of Senate Bill (SB) 1078, under the mandate of Pub. Util. Code Section 701.3 (Section 701.3).[3] As such, we will enforce the purchase requirements of our previous order in 2003, and without DWR credit support, if necessary. We also provide that any renewable procurement undertaken prior to a utility becoming creditworthy will count toward its RPS requirement.

We also state our preference to adopt a uniform incentive mechanism to provide an opportunity for utilities to balance risk and reward in the long-term procurement process. We direct SDG&E to convene a public workshop to flesh out a consensus proposal for the incentive mechanism.

II. Procedural Background

On October 29, 2001, the Commission issued an Order Instituting Rulemaking (OIR), designated as Rulemaking (R.) 01-10-024, to

(1) establish ratemaking mechanisms to enable California's three major investor-owned electric utilities, Edison, SDG&E, PG&E to resume purchasing electric energy, capacity, ancillary services and related hedging instruments to fulfill their obligation to serve and meet the needs of their customers, and

(2) consider proposals on how the Commission should comply with Section 701.3 which requires that renewable resources be included in the mix of new generation facilities serving the state.

A preliminary scoping memo contained in the OIR set a schedule for respondent utilities to file procurement proposals and for interested parties to comment on the proposals, and scheduled a prehearing conference (PHC) for

[3] All statutory references refer to the Public Utilities Code, unless otherwise noted.

January 8, 2002. SDG&E and PG&E filed their proposals on November 21, 2001 and Edison late-filed its proposal on November 27, 2001. Interested parties requested and were granted a one-week extension until December 21, 2001 to file comments. In their comments, many parties urged the Commission to develop a fully integrated resource planning process but to only decide quickly those issues that need to be in place for the utilities to resume full procurement responsibilities no later than January 1, 2003, as anticipated by ABX1 1 (Keeley).

The procedural schedule and scope for the initial proceeding was adopted in the April 2, 2002 Assigned Commissioner Ruling (ACR) Establishing Category and Providing Scoping Memo (April 2 Scoping Memo). The ruling explicitly emphasizes interim procurement methods for the immediate issue of restoring the utilities' obligation to serve and meet the needs of their customers no later than January 1, 2003. The ruling requested briefs on transition issues that needed to be resolved and set a schedule for the respondent utilities to file procurement plans for 2003 with accompanying testimony. The April 2nd Scoping Memo schedule anticipates a proposed decision in September, with a final Commission decision in October 2002. The only consideration of procurement practices post-2003 was for procurement of renewable resources to address our mandate under Section 701.3.

The respondent utilities served their testimony on May 1, 2002. As part of this testimony, Edison proposed the Commission adopt a process by which it could immediately begin contracting for up to a five-year term for capacity and related products in conjunction with the DWR. On May 6, 2002, Edison filed a motion requesting that this proposal be approved on an expedited basis outside of the hearing process. By ruling on May 15, 2002, the scope of this initial phase was expanded to consider Edison's May 6th proposal in the hearing process.

Evidentiary hearings were held from June 10 through July 3, 2002. A bifurcated briefing schedule was set, with briefs on transitional procurement issues, to include Edison's May 6th Motion and how the Commission should address renewable energy procurement and Qualifying Facilities (QFs) under any authority granted, due first on July 12, 2002.[4] These issues are the subject of D.02-08-071 issued August 22, 2002. We address all remaining issues relating to utilities resuming procurement in January 2003 here.

As addressed in the April 2, 2002 scoping memo, additional issues relating to the assessment of long-term resource needs still need to be addressed in subsequent phases of this proceeding. The Commission will address therein, on an integrated basis, the utilities use of long-term procurement contracts, utility ownership of generation and other resource options such as demand response, energy efficiency and transmission infrastructure additions.

These resource planning decisions will ultimately impact the amount of remaining residual net short that utilities will have to procure on a short-term basis in future years under the process we adopt today. They will also inform us as to the need for modifications to our current policies, restricting reliance on

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[4] Parties who participated actively in the proceeding are the respondent utilities, Aglet Consumer Alliance (Aglet), Alliance for Retail Energy Markets and the Western Power Trading Forum (ArM / WPTF), California Biomass Energy Alliance (CBEA), California Cogeneration Council (CCC), California Consumer Power and Conservation Financing Authority (California Power Authority), CEC, California Wind Energy Association (CalWEA), Center for Energy Efficiency and Renewable Technologies (CEERT), Cogeneration Association of California (CAC), Consumers Union (CU), Independent Energy Producers Association / Western Power Trading Forum (IEP / WPTF), Office of Ratepayer Advocates (ORA), Ridgewood Olinda, LLC (Ridgewood), Sempra Energy Resources (SER), The Utility Reform Network (TURN), and Union of Concerned Scientists (UCS).

spot markets, reducing price volatility, and levels of reserves that utilities need to have to maintain reliable service to their customers.

III. Returning the Respondent Utilities To Full Procurement

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. The utilities' obligation to serve customers is mandated by state law and is part and parcel of the entire regulatory scheme under which the Commission regulates utilities under the Public Utilities Act. (See, e.g. Pub. Util. Code Sections 451, 761, 762, 768, and 770.) As we explained in D.01-01-046, a bankruptcy filing or the threat of insolvency has no bearing on this aspect of state law. Even utilities that file for reorganization must serve their customers. The public's safety, and the economy's health will be impaired if the utilities avoid this obligation to serve.

In this section, we address the utilities' capability to meet their obligation to serve. Pursuant to the Proclamation issued by Governor of the State of California on January 17, 2001, SB7 and AB1X 1, the state stepped forward in early January and February 1, 2001 to buy power on behalf of end-use customers on an emergency basis.[5] California took this unprecedented step due to the financial distress PG&E, Edison, and SDG&E were experiencing as a result of the combination of extreme market dysfunctions, AB 1890 rate freeze requirements and because many of the merchant sellers refused to sell to the utilities and the federal government (through the Federal Energy Regulatory Commission (FERC)) had not issued a comprehensive must-offer order requiring merchant

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[5] The January 17, 2001 Proclamation is found at the Appendix B of D.02-02-051 (2002 Cal.PUC LEXIS 170).

sellers to sell power to the utilities.[6] Since then the state, through DWR, has procured all the residual net short (RNS) requirements directly for utility customers, i.e., DWR is buying power to meet all energy needed beyond the utilities' own retained generation, both by entering into long-term contracts that secure substantial amounts of energy through 2008 and by buying power through the Independent System Operator (ISO). As a result of these actions, we must recognize that the procurement responsibilities Edison, PG&E, and SDG&E will face on January 1, 2003 are substantially less than those they faced in 2000. Today, an average of 90% of bundled service energy requirements are provided by existing DWR and utility contracts as well as utility retained generation. Further, in anticipation of Edison, PG&E, and SDG&E resuming full procurement on January 1st, the Commission recently granted the utilities permission to use more of the state's credit, interest free, to cover their projected procurement needs in 2003 – 2008. (See D.02-08-071, issued August 26, 2002.)

Edison and PG&E assert that they cannot resume full procurement until they have an investment grade credit rating. Edison contends that without an investment grade credit rating, there is no assurance that it will be able to effectively procure power. PG&E states that it needs investment quality credit status in order to attract prospective suppliers and avoid the punishing cash and collateral demands placed on uncreditworthy purchasers. SDG&E has an investment grade credit rating but argues that it should not be returned to the procurement role until at least one, and preferably both, of the other two utilities are returned to that role.

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[6] While Edison and PG&E have had their credit ratings downgraded below investment grade, SDG&E is an investment grade utility.

We do not agree that Edison and PG&E need to obtain an investment grade credit rating prior to resuming the procurement role. We share the goal of Edison and PG&E regaining an investment grade rating, but this is not a necessary precondition to resuming procurement. In fact, many in the energy industry today do not have an investment grade credit rating and are able to conduct business. On the record developed in this proceeding, CCC states that its members are willing to enter contracts with both utilities. In its opening brief, Sempra Energy states "if the Commission were to adopt procurement rules and mechanisms providing reasonable assurances to sellers that they will not face undue exposures to defaults or payment delays resulting from regulatory uncertainties or litigation, SER would make its offers to Edison accordingly, regardless of any actions taken by Moody's and/or Standard & Poor with respect to Edison's credit rating." Therefore, in this decision we adopt a procedural process and timely cost recovery mechanisms that are designed to make Edison and PG&E capable of entering into procurement transactions without undue regulatory uncertainties.

Both Edison and PG&E have strong cash flow and a stable and secure revenue stream; these are attributes that should make them very attractive to merchant generators and energy trading companies who produce and sell electricity. As we explain below, Edison's financials quantitatively meet investment grade standards and it is on the verge of regaining an investment grade rating; the ratemaking treatment adopted here supports that effort. PG&E is presently in bankruptcy but under our proposed Plan of Reorganization, PG&E will be able to quickly emerge from bankruptcy as a creditworthy entity, because it will meet the quantitatively objective criteria for investment grade ratings.

Aglet presented convincing evidence demonstrating that utility arguments regarding procurement risks in 2003 are exaggerated and that both Edison and PG&E can resume procurement today without an investment grade rating. ORA and the CEC come to the same conclusions. We need not wait for the rating agencies to act before ordering the utilities to resume procurement. We expect Edison and PG&E to exercise the transitional authority we granted in D.02-08-071 by securing sufficient capacity contracts for their projected residual net short requirements. As a result, we expect that their procurement needs in 2003 and beyond will be well within their ability to finance. The remaining RNS after this transitional procurement can be met through a combination of directly contracting with wholesale energy suppliers and purchases in the real-time energy markets administered by the ISO.[7] We briefly discuss here why each are viable options for Edison and PG&E.

We recognize that several of the major wholesale energy traders and generators that operate in California are in financial trouble today. As examples, we cite here, articles in the general public press on Calpine, Dynergy, Duke Energy, Enron, Mirant, Reliant, and Williams Company. Current energy prices remain at or below low historical averages and these energy sellers operate in largely unregulated, price volatile markets with low liquidity and high leverage. It is reasonable to conclude that these companies will find that entering into contracts with Edison and PG&E will be very attractive. Edison and PG&E will be operating in a regulated arena with ratemaking mechanisms that ensure timely and stable cost recovery. Both utilities also have strong cash positions and

[7] Edison and PG&E can still meet their RNS even if they do not procure all the capacity authorized in D.02-08-071.

cash flow, arising from current rates authorized well above current operating costs. Collateral, in the form of bank letters of credit or other financial instruments, is currently available to both companies. Each company could for example agree to pay more rapidly than on a monthly billing basis, thus reducing perceived risks of failure to pay. As we discuss below, Edison has been able to quickly pay down its accrued debt and PG&E is positioned to do the same.

To the extent that RNS is not met through contracting with wholesale traders and generators, PG&E and Edison can also procure remaining RNS in the ISO markets. Because they do not now meet the ISO's accepted credit criteria, both utilities will need to post security amounts as set forth under Section 2.2.3.2 of the ISO's tariff.[8] The utilities each submitted exhibits estimating the collateral they would need in order to participate in the ISO markets and procure necessary resources to meet their load. We grant here the motions of PG&E and Edison to have these exhibits entered into evidence as Exhibits 139C and 140C. We compare these exhibits with our own analysis of ISO collateral requirements and the cash balances and collateral analysis presented by Aglet.

Pursuant to the ISO tariff, Edison and PG&E must post security for an estimated liability for outstanding charges based on trading volumes, the grid management charge, and other market charges for the preceding 60-90 day settlement period. (ISO tariff Section 2.2.7.3.) The outstanding liability for the 60-90 day settlement period will fluctuate continuously. The collateral required for the utilities to conduct power purchases (PPs) and meet contract obligations

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[8] The ISO is currently reviewing these requirements and has asked the Commission to assist in this review. See ISO letter to President Lynch dated August 23, 2002.

will be largely influenced by the allocation of DWR contracts among the utilities, the amount of power left to be procured absent DWR backing, and overall market prices. We recognize that PG&E and Edison will require flexibility in posting the security amounts, because the amount will vary considerably depending on, for example, energy prices, the degree of forward hedging, and seasonal variations.

We find that the assumptions in Exhibits 139C and 140C are speculative and also may represent high estimates as the amounts needed will vary based on energy prices and supplier terms. Also, as we granted transitional authority in D.02-08-071 for Edison and PG&E, we believe the level of collateral requirements that must be posted to resume resource procurement and participate fully in the ISO will likely be less than PG&E and Edison predict. As we move closer to January 1, 2003, we expect that the accuracy of the estimated collateral requirements will continue to improve.

Aglet provides convincing evidence that Edison's and PG&E's recent recorded earnings, cash positions, and anticipated cash flows compare favorably with the collateral and procurement amounts required, even using the high estimates of Exhibits 139C and 140C. Aglet testifies that PG&E's available cash has grown from $126 million at the end of 2000 to $2.582 billion in April 2001 to $4.495 billion at the end of April 2002. PG&E's quarterly earnings have risen from losses in fourth quarter 2000 and first quarter 2001 to earnings of $737 million in third quarter 2001; $557 million in fourth quarter 2001; and $590 million in first quarter 2002. Aglet also notes that due to its bankruptcy PG&E cannot use available cash to repay pre-petition debts, but it can use the cash for post-petition procurement operations. Procurement is a necessary and normal part of utility operations and therefore, we do not think bankruptcy court approval is required for PG&E to perform this. However, if PG&E believes it requires approval of the U.S. Bankruptcy Court, it should petition for approval immediately.

Edison's available cash totalled $1.303 billion in March 2002, after paying more than $3 billion in past due payments to debt holders and energy providers. Its quarterly earnings totalled $651 million in third quarter 2001, $2.304 billion in fourth quarter 2001, and $142 million in first quarter 2002. Edison testifies that it expects to recover all undercollections under its settlement agreement before the end of 2003. Exhibit 52C shows that Edison's estimated cash positions at the end of 2002 and at the end of 2003 exceed reference case 2003 procurement costs and base or reference case collateral needs. Also in evidence is Standard and Poor's February 20, 2002 report that states Edison's cash flows are consistent with investment grade.

Based on the above discussion, we find Edison and PG&E are capable of resuming full procurement and, under their continuing obligation to serve, should do so beginning on January 1, 2003. We direct Edison and PG&E to take whatever steps are necessary to post the required ISO collateral in order to resume Scheduling Coordination and purchase of the net-short. The utilities should also post the contract and procurement related collateral required to secure resources to meet their loads. We expect that PG&E and Edison will efficiently manage their collateral requirements in a manner that is beneficial to ratepayers. Edison and PG&E should update their collateral requirement estimations, specifically accounting for ISO security requirements and other contract and procurement related collateral costs, in their updated procurement plan filed on November 12, 2002.

IV. Procurement Plan Elements

The procurement plans already filed by PG&E, Edison, and SDG&E vary in depth of detail and comprehensiveness. We adopt here the framework for each utility's plans, specifying the detail and accuracy of information that shall be needed in order to quickly process and approve transactions beginning January 1, 2003. While we recognize the urgency of having a procurement plan in place by January, we also understand the importance of beginning longer-term (up to 20-year) resource planning now. Therefore, we adopt a two-part procurement planning process to cover short-term and long-term needs, as detailed further in this decision. Both short-term and long-term procurement plans should include the same elements, as described in detail below.

The development of any procurement plan begins with an assessment of need. As of May 1, 2002, the date the utilities filed their procurement plans, the Commission had yet to resolve the allocation of DWR contracts among the three utilities. The allocation of DWR contract is one of the key factors underlying the derivation of each utility's residual net short position. On September 19, 2002, the Commission adopted D.02-09-053 specifying the allocation of the DWR long-term contracts among the three respondent utilities. That decision orders PG&E, Edison, and SDG&E to submit revised estimates of their respective net short position based on the final adopted allocation of the DWR contracts.

While D.02-09-053 removes a large measure of uncertainty in the calculation of each utility's residual net short position, a second variable emerged during the course of the proceeding which impacts the procurement needs of the utilities in 2003: the adoption of transitional procurement authority with DWR's credit support. D.02-08-071 authorizes the three utilities to enter into multi-year procurement contracts based on a conservative estimate of on-peak hourly residual net short needs. We anticipate that proposed contracts brought forward under the authority granted in D.02-08-071 will be filed by early November 2002 with a Commission resolution on the contracts issued before the end of the year. To the extent the utilities enter into contracts under the transitional procurement authority granted in D.02-08-071, the utilities' residual net short requirements will diminish, thereby reducing the need for additional procurement authorized in this decision.

Now that a decision resolving DWR contract allocation has been adopted and the utilities' transitional procurement process is underway, the utilities shall update their residual net short estimates to reflect these developments.

We now turn to the remaining components of utility procurement plans. AB 57 enumerates the following elements of a utility plan:

- An assessment of price risks across the utility portfolio.
- Definitions of the various products to be procured, including support and justification for the types and amounts of products to be procured.
- Defined duration of the plan.
- Duration, timing, and amount of each product to be procured.
- Use of a competitive bid system.
- An incentive mechanism, if one is proposed.
- Upfront standards and criteria to guide procurement transaction cost recovery.
- Procedures for updating procurement plans.
- A demonstration that the plan will meet residual net short needs and utilize demand side reduction programs.

- A showing that the utility will procure renewables and pursue demand reduction programs in accordance with the legislation.
- The utility's risk management policy and strategy.
- A plan for achieving increased diversity in supplier representation and fuel sources.
- A mechanism for recovering the utility's procurement-related administrative costs.

As detailed further below, we will require the utilities to file a short-term procurement plans on November 12, 2002 to include D.02-09-053 contract allocation and transitional procurement, as well as a long-term plan on February 15, 2003. None of the utility filings to date meet the detail we find necessary for the plan elements set out above. In particular we expect the utilities to provide more information on:

- A specific risk management strategy;
- Types of products to be procured over specific time-frames; and
- Actual quantities to be procured.

V. Resource Options

In designing their procurement plans, the utilities should undertake a resource planning effort to include procurement from a mixture of different sources with various environmental, cost, and risk characteristics. Utilities fully responsible for meeting their customers' resource needs should plan among all of the following options: conventional generation sources (with a variety of types of ownership structures), renewable generation (including renewable self-generation), distributed and self-generation, demand-side resources, and transmission. In addition, utilities should plan to meet a reserve requirement. Each of these elements is discussed briefly below.

In addition, we encourage the utilities to work cooperatively with the CEC and the Power Authority on planning for all of the resources discussed below. The CEC can streamline regulatory oversight of some aspects of the resource planning portfolio, as well as assist with renewable resource procurement through their PGC funding authorized in SB1038. The Power Authority can also assist in providing financing and programmatic support to a number of the resources described below. The utilities should recognize and take advantage of the complementary roles of these agencies, as well as DWR, in the procurement process.

A. *Conventional Generation*

In their resource planning, the utilities should consider both utility owned / retained and merchant generation sources. While in the short-term the sources of such procurement may be limited, for the longer-term utilities should assess costs and benefits of various contracting and ownership strategies. In addition, a discussion of fuel risk should be explicitly incorporated into the procurement planning process.

B. *Renewable Resources*

Before giving specific direction on renewable procurement, it is important to have a clear definition of what constitutes "renewable generation." SB1078 defines "renewable generation" as electricity produced by the following technologies: biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology. Specific existing municipal solid waste (MSW), small hydroelectric and geothermal facilities are eligible only for inclusion in the utilities' baseline, as specified in SB 1078. Facilities must be located in the state or near the border of the state with the first point of connection to the Western Electricity Coordinating Council (WECC) transmission system located within the state.

In addition to these provisions in SB1078, we include in our definition of renewable generation, for purposes of compliance with both D.02-08-071 and SB1078, renewable distributed generation (DG) on the customer side of the meter. Including renewable DG as part of our definition will serve to encourage its installation, regardless of whether the utility purchases the output or whether it serves to meet on-site load. The full output of renewable DG should be credited to meeting the RPS or D.02-08-071 requirements.

1. Renewable Procurement Prior to Full RPS Implementation

Throughout this proceeding, we have demonstrated our commitment to renewable resource procurement. In the period since the issuance of our transitional procurement decision, the Legislature has passed, and Governor Davis has signed, two pieces of legislation with significant implications for the renewable generation aspects of this proceeding. These bills are SB 1078 and SB 1038.[9] Under these statutes, California is embarking on a multi-year RPS program, supported by the subsidies and research of the Energy Commission's Renewable Energy Program (REP). This Commission has been given several important tasks in pursuit of the goals of the RPS, and we must start now if the effort is to succeed.

[9] SB 1078 adds Sections 387, 390.1, 399.25 and Article 16 commencing with Section 399.11 to Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code.

We also must be certain that the direction provided in the transitional procurement decision is implemented in the coming months. Full implementation of the RPS program will be constrained to some degree by SB 1078's statutory requirements regarding the credit ratings of the utilities. It is, therefore, more important than ever that the partnerships authorized for the purpose of transitional procurement result in substantial procurement of renewable generation. We note, moreover, that our mandate to develop renewable generation resources under Section 701.3 remains a guiding principle in this proceeding, and we restate our commitment to that goal.

We direct the utilities to submit, with their short-term procurement plan on November 12, 2002, a report on the status of their procurement under the renewable generation mandate of our previous order. Utilities should document their plan for meeting the 1% procurement required in D.02-08-071, including what has been accomplished and what remains to be done. Commission staff is available to facilitate compliance with this direction.[10]

We also ask that parties with information regarding the contract status of existing renewable facilities provide the Commission with an update on negotiations with the utilities. Such parties should provide this information as soon as they so desire. Similarly, we ask that the CEC, to the extent it has information, provide an update on the status of those potential new facilities it has previously identified, and the extent to which those facilities are engaged in the transitional procurement process.

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[10] To clarify the directives of the transitional procurement decision, we state the following: the transitional benchmark price of 5.37c / kWh is an inclusive, "all-in" price,

Footnote continued on next page

Our renewable requirement contained in D.02-08-071 remains in effect under Section 701.3 and should be adhered to, with or without DWR credit support.

We also clarify, to the extent that D.02-08-071 may have been ambiguous, that procurement of 1% of the utility's retail sales in 2001 (including DWR quantities) is the overriding requirement for renewables in that decision. Utilities are required to contract for this amount of electricity from renewable sources by the end of 2003.

Utilities are not required to procure all resources that offer prices of less than 5.37 cents per kWh (the interim benchmark price). That benchmark was set for purposes of determining per se reasonableness for cost recovery purposes, but does not require that utilities acquire all resources at that price. D.02-08-071 in fact requires a competitive solicitation process for renewables that may produce bids either below or above the benchmark, with varying contract lengths.

We also clarify that any renewable procurement conducted under the transitional authority will count towards the utilities' RPS requirements going forward.

2. Implementing the Renewable Portfolio Standard Program

We must also lay the groundwork for full RPS implementation, and much of what is needed exists in the record of this proceeding. SDG&E, as a creditworthy utility, must begin the RPS process immediately. Drawing from the

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and the 1% purchase requirement is to be calculated based on 2001 sales figures,

Footnote continued on next page

existing record, we ask that parties brief what is required to implement the RPS legislation and relevant portions of the REP bill, with particular emphasis on the following:

> *Market Price Benchmarking.* It is clear that this will be the first and most important task for the Commission in this process. We are directed by statute to consider long-term, fixed-energy prices for non-renewable generation, long-term ownership costs for new facilities, and the value of specific electrical products. Hence, there will be more than one benchmark price to set. We ask that parties, in particular the CEC, comment on appropriate methodologies to be employed in this process.
>
> *Least Cost/Best Fit.* We are directed to provide the utilities with the criteria they are to use in selecting renewable bids, specifically including transmission and "ongoing utility" expenses. Least cost/best fit needs a fuller exposition if it is to provide any real procurement guidance in the future. Parties should provide a coherent definition of the least cost/best fit concept, and develop it in the context of transmission costs and other relevant considerations.
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> *Flexible Compliance.* We are to allow utilities to catch up procurement shortfalls over as many as three years, and to allow excess procurement to be "banked" for credit in the future. Parties should comment on how this compliance system should be designed, including specifically addressing whether a three-year rolling average would be workable. Parties should also comment on whether the Commission should consider inter-utility trading of renewable energy credits (RECs).
>
> *Inter-Agency Collaboration.* Parties should comment on how the tasks assigned to the Commission and the CEC intersect, and on how the two agencies can best collaborate to achieve the RPS goal.
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> *Standard Contract Terms and Conditions.* Utilities and parties representing renewable developers are particularly encouraged to

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including DWR power.

provide guidance on how to structure standard contracts for renewable procurement.

Optimal Utilization of Public Goods Charge Funds. Procurement under the RPS program will be constrained by the availability of funds under the CEC PGC program. Parties should discuss, in detail, how far these funds will go towards meeting the RPS goal, and how best to coordinate their usage with the CEC.

Developing a Balanced Renewable Portfolio. The legislature and Governor have expressed their intention that the RPS bill result in the development of a broad range of renewable technologies. Given the constraints imposed by the market-benchmark criteria and the relative scarcity of PGC funds, it is not clear that this will be the necessary result. Parties are asked to comment on strategies the Commission may employ to pursue a diversified renewable portfolio.

Pursuing Other Commission Mandates. Since the inception of this proceeding we have signaled our intention to pursue the mandate of Section 701.3. We ask that parties comment on the relationship of this mandate to the direction provided in SB 1078, and on any actions the Commission should take to comply with Section 701.3 and make it compatible with the RPS program.

We request parties through comments on January 6, 2003 and reply comments on January 13, 2003 to provide a proposed procedural process and schedule for implementing SB 1078. A procedural schedule shall be set by Assigned Commissioner's Ruling. The Commission will submit an implementation report to the Legislature by June 30, 2003, as required by SB 1078.

We fully intend to secure an increase in renewable generation for the state as a result of the transitional procurement process authorized previously, and will see to it that the RPS program is implemented effectively and with an eye to the necessary detail. It will be an iterative process, but there can be no doubt as to the direction we are heading. The RPS Program is law, and we will do our part to implement it.

C. *Distributed and Self-Generation*

The utilities should explicitly include provision for distributed generation and self-generation resources in their procurement plans. In this definition, we also include on-site cogeneration resources, including qualifying facilities. These resources encompass a broad and diverse set of technologies to fit a variety of procurement needs. In addition to providing capacity and energy benefits, they can offer transmission and grid-support benefits that should be included in the utilities' procurement plans.

D. *Demand-Side Resources*

As we mention several times in this decision, we expect the utilities to include demand-side resources as part of their procurement portfolio. These resources can take two primary forms: energy efficiency and demand response. We discuss each in turn below.

1. Energy Efficiency

Utilities should include in their plans procurement of baseload energy reductions in the form of energy efficiency. Utilities should consider investment in all cost-effective energy efficiency, regardless of the limitations of funding through the public goods charge (PGC) mechanism. The commission may authorize additional energy efficiency expenditures beyond the PGC as part of this overall procurement process, and may eventually want to move toward consideration of an energy efficiency portfolio standard similar to the RPS for renewables that is now state law. We will consider this concept in a later phase of this proceeding. In addition, we are considering other policy issues related to energy efficiency policy, programs, and implementation in R.01-08-028.

2. Demand Response

While energy efficiency resources can often meet baseload procurement needs, demand response can fill on-peak requirements. As with energy efficiency, the utilities should consider all cost-effective investment in demand response that meets their procurement needs.

Several efforts currently underway should give the utilities a head-start in procuring additional demand response resources. The Power Authority currently has a Demand Reserves Partnership program, under contract to DWR, to provide demand response resources through the ISO ancillary services market. This DWR contract is assignable from DWR to the utilities to use as part of their procurement plan. While we do not direct immediate contract assignment in this decision, we require the utilities to include the available resources in their long-term procurement plan, as well as a transition plan for eventual assignment of the contract.

In addition, the PUC, CEC, and Power Authority are cooperating in a joint rulemaking (PUC docket R.02-06-001), to design strategies, tariffs, and programs for additional demand response resources. In the course of that proceeding, we expect to identify quantitative targets for utilities to procure in demand response resources, to become part of their long-term procurement plans.

E. *Transmission*

To the extent that transmission investment can meet or offset procurement needs, utilities should explicitly include transmission in their resource plans. The Commission already has an investigation (I. 00-11-001) addressing transmission resource needs, and the results of that planning process should be included in utility resource assessment in this proceeding.

F. *Reserves*

We also make explicit, in this decision, that the IOUs are responsible for procuring reserves on behalf of their customers' needs, as part of their continuing obligation to serve. We are aware that there is an interagency working group, led principally by a Power Authority proceeding, addressing the issue of the appropriate reserve margin, and that the work of that group is not yet complete. In the interim, however, it is important that the IOUs be responsible for procuring some reserves. We set that level at 15% provisionally in this decision, subject to reexamination once the Power Authority proceeding and the interagency group come to a final recommendation.

In addition, we require that the utilities meet at least 25% of those reserve requirements through investment in demand response resources. This requirement is also a minimum requirement subject to revision in policy decisions that will emanate from our demand response proceeding (R.02-06-001).

VI. Utility Options for Procurement Transactions

In their procurement plans, the utilities shall provide detailed descriptions of the various transaction processes they will use to meet their residual net short needs and hedge price risk. In this decision we authorize the utilities to procure products using any of the following methods: a competitive bid process, bilateral contracts (using accepted offers from a competitive bid process as a price ceiling), purchases through transparent markets, inter-utility exchanges, and the ISO markets.

A. *Competitive Solicitations*

- Requests for Offers / Requests for Proposals. Procurement plans shall specify the steps of the solicitation process to be used. The process shall be consistent with the competitive solicitations in use now under transitional procurement authority.

- Competitive solicitations may be all-source or may be segmented to allow similar sources to compete with each other, but must cover all of the sources described in section V above.
- Solicitations should be widely distributed (starting with bidders list used under transitional procurement authority). Required items shall include among other things:
  - Description of product requirements
  - Term
  - Minimum and maximum bid quantities
  - Scheduling and delivery attributes
  - Credit requirements
  - Pricing attributes
- Each utility shall update its procurement plans to specify and describe the evaluation tools and methodology it will use to rank and select bids, such as:
  - Minimum requirements for counter-party creditworthiness
  - Minimum number of bids that must be received
  - An evaluation of cost-to-risk tradeoff (consumer risk tolerance level) of the various bids

B. *Transparent Exchanges*

- Approved utility plans will identify and describe the various electronic energy trading exchanges that each utility proposes the use (e.g., Bloomber, Trade Spark, Intercontinental Exchange).
- The procurement plans shall demonstrate that the identified and electronic trading exchanges the utility intends to use provide transparent prices.

C. *ISO Markets: Hour Ahead and Imbalance Energy and Ancillary Services Markets*

- ISO spot market transactions are authorized to balance system and meet short-term needs.
- Approved procurement plans shall describe procurement strategies for avoiding over-reliance on the spot market. Utilities should plan to procure no more than an average of 5% of their resource needs annually through spot market purchases.

D. *Inter-Utility Exchanges*

- Traditionally, regulated utilities entered into seasonal and long-term inter-utility exchange agreements (IUE) with other regulated utilities and other load-serving entities such as the Bonneville Power Authority (BPA). Through private negotiation the specific terms were crafted to best fit the resources and needs of both parties. The commission reviewed the reasonableness of these transactions in the annual ECAC reasonableness review proceedings. There were even some prudence disallowances adopted by the Commission. Payment was typically non-cash with capacity and energy balanced to reflect the seasonal and locational value of the power. Opposite peaks in the northwest and southwest lead to large-scale transactions.
- Unless we adopt specific guidelines for negotiated IUEs these deals would only occur through an RFO process, which is unlikely to be as successful in price or in meeting specific needs of both parties. By adopting the benchmark and other guidance discussed below we allow negotiated IUEs to be included for approval in the monthly advice letter filings.
- The important elements to justify an IUE as reasonable would include:
  - Cost-effective reductions to seasonal or specific RNS,

- Cost effective reductions to seasonal or specific Residual net-long positions.

To justify as cost-effective an IUE to reduce RNS (acting as a buyer), the utility will have to demonstrate that at the time of executing the IUE agreement the expected costs for the repayment was less than the avoided incremental costs at the time of delivery. This determination would be based upon the incremental costs of the existing delivery time and repayment time portfolios available when the IUE is negotiated. For example, if the delivery's existing portfolio incremental transaction cost or the most recent RFO bids for the delivery period are more than $100 and if the repayment portfolio's incremental transaction cost was $100 or less then the IUE could be deemed reasonable when filed by advice letter. This total transaction cost would account for the differing values of capacity, energy, ancillary services, and volume of energy in the two sides of the transaction.

To justify as cost effective an IUE to reduce residual net long positions (as a seller being repaid in capacity, energy, or ancillary services) the utility would have to demonstrate that the average portfolio value of the time of repayment is higher than the forecast of spot prices when the energy would otherwise be dumped as surplus.

E. *Utilities may Provide Showing for Bilateral Contracting as an Additional Alternative Procurement Method*

- We are receptive to the potential use of bilateral contracts. For the Commission to approve the use of bilaterals, the utilities updated procurement plans must demonstrate: (1) that without authorized bilateral transactions, the utilities would lack the ability to adequately hedge their ISO spot market price exposure; and (2) that the proposed process for entering into bilateral contracts reflects an open competitive bidding

> process with the goal of producing a contract price representing a reasonable approximation of what a competitive market would provide.

VII. Specific Types of Transactions

Several parties discussed the types of products or transactions that should not be authorized for interim procurement. In their testimony, the CEC, TURN and ORA recommend limiting or prohibiting certain types of transactions.

CEC gave several recommendations for restrictions on utility transactions, including: prohibiting utilities from entering into bilateral contracts with affiliates, limiting procurement arrangements to one year or less, prohibiting any utility from entering into contracts that limit the operations of any of its utility retained generation (URG) units (with the exception of "interchange" transactions, where one utility sends energy to another over a specified time frame in exchange for energy at another time).

ORA recommends that the utilities be prohibited from entering into asymmetric derivative contracts. ORA does not provide an argument as to why such types of arrangements should be disallowed. Edison, in its rebuttal testimony, found the ORA position to be inconsistent, citing ORA's support for hedging devices such as call and put options.

The use of financial instruments (derivatives) in such a manner that their effect would be to amplify any price risks shall not be allowed. By its definition, a hedge is used based upon an entity's underlying portfolio position to mitigate price risk; actions taken by a utility that amplifies risk are prohibited.

The procurement products listed in Table 1 represent a compilation of the types of procurement products requested by the respondent utilities in testimony, as well as products that we consider appropriate to meet procurement needs. While we authorize the utilities to procure the products described in Table 1, this list should not be considered exhaustive. The procurement plans must specify each utility's comprehensive list of products, including a definition of each product type and the associated benefit/cost attributes.

Table 1		
Transaction	**Description**	**Benefit /Cost**
Day ahead (purchase, sale, or exchange)	Purchase pre-scheduled energy or load reductions at fixed price	Need less day-ahead (or spot) energy in the spot market / Vulnerable to price volatility
Real time (purchase or sale)	Hour-ahead and energy imbalance transactions or load reductions	Balances short term needs / Vulnerable to price volatility
Forward Energy (purchase or sale)	Fixed amounts of energy over a specified period of time (e.g., 7x24, 6x16, super-peak, and shaped products) Could be fixed price.	Reduces price risk / Risk that prices will be below contracted rate.
Forward Energy (demand side)	Baseload usage reduction through investments in permanent energy efficiency	Reduces price risk and cost overall
Capacity (purchase or sale)	Right to purchase energy in exchange for capacity payment. If exercised, buyer also pays incremental energy charge at specified rate.	Reduces spot price risk / Reduced risk comes at cost of reservation and energy charges
Capacity (demand side)	Right to purchase load reductions for capacity payments	Provides dispatchable reliability
On-site energy or capacity	Energy or capacity products self-generated on the customer side of the meter	Provides locational reliability and lowers price risk through supply diversity
Tolling Agreement	Type of capacity product where buyer hedges fuel cost risk by providing the gas supply, transportation, and storage	Reduces peak price risk / Buyer pays reservation or capacity charges, and is open to gas price risk.
Peak for off-peak exchange	Trades peak energy for off - peak energy (x peak MWh < y off-peak MWh)	Reduces peak price risks / Increases off-peak price risks
Seasonal exchange	Buyer receives peak energy in Summer and returns peak	Reduces summer price risk / Increases winter peak price

Table 1

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

VIII. Price Benchmarking and the Development of an Incentive Mechanism

A. *TURN's Proposed Price Benchmark Strategy*

TURN's testimony regarding price benchmarks highlighted several important issues facing this Commission regarding how to reasonably measure what constitutes "fair" prices. As history has all-to-painfully taught us, the energy markets serving California can be manipulated, so the going rate for energy may not necessarily be the price that would be prevalent in a truly competitive market.

TURN proposed a system for evaluating the reasonableness of utility transactions based upon benchmarks created to approximate actual costs for generation. TURN suggested such a proposal to minimize the effects of potential gaming by producers, as well protect against any gaming that might develop under incentive regulation.

The TURN proposal is based upon the calculations used by the FERC and ISO to determine costs for providing generations services. The FERC uses a measure of short-term utility procurement costs using a Short-Run Marginal Cost (SRMC) approach. The California ISO uses the incremental heat rate of the plant that is on the margin, multiplied by the going price for gas to find the Estimated Competitive Price (ECP) for energy.

As proposed, a SRMC or ECP would be used as a benchmark for evaluating the reasonableness of contracts of up to five years in duration. All contracts that come in at or below 110% of the benchmark price (on average for a one year period) would automatically be deemed reasonable; those above the 110% limit would trigger a reasonableness review. In a reasonableness review, the utility would be required to demonstrate that it gave every reasonable effort to procure at or below the benchmark price.

B. *ORA's Proposed Benchmark Strategy for Portfolio Management*

ORA provided a detailed discussion of what it called a "rule-based system for utility procurement" that would guide how the utilities managed their portfolio to minimize risk. ORA's recommended portfolio management system would require the utilities to continuously adjust its portfolio based upon periodic updates of price forecasts and risk analysis.

ORA's rule-based system can be split into two major analytical tasks: (1) forecasts and stress testing of forward prices, and (2) risk analysis based upon the forecasting. The outcome of the risk analysis would guide how the utility would manage its portfolio. ORA recommended that each utility undertake its own forecasting effort, and evaluate the price exposure of its portfolio using low-probability scenarios (i.e., extreme system conditions). The final portfolio would be adjusted frequently to minimize price risks.

C. *Discussion*

While we do not adopt the TURN methodology for utility procurement in this decision because it would necessitate after-the-fact reasonableness reviews, we agree with TURN that cost-based benchmarks are a useful tool in determining the health of California's energy markets.

We also do not adopt ORA's rule-based system in this decision. We appreciate ORA's robust methodology for calculating forward prices, and agree with ORA that the utilities should focus on a portfolio management strategy that minimizes price risk to ratepayers. We do not adopt the ORA proposal because we find it is in the ratepayers' interest to allow utilities more flexibility in managing its portfolios than a formulaic approach would provide.

Though we adopt neither the TURN nor the ORA approach to price benchmarking, we believe both proposals point to the necessity both of determining what "just and reasonable" prices are in this market and of measuring utility procurement performance in light of the reality of the market.

We find that the TURN proposal could be modified to trigger, rather than after-the-fact reasonableness review (which AB57 steers us away from undertaking), an incentive mechanism that rewards the utilities for beating the benchmark and penalizes them for exceeding it, within certain limits. We seek further input from parties on the proper design of such an incentive mechanism, for purposes of the utilities' long-term procurement plan. To facilitate this input, we direct SDG&E, in cooperation with the other utilities, to sponsor an all-party workshop to develop a consensus proposal for an incentive mechanism. To the extent that consensus is reached, the proposal should be filed as part of the utilities' long-term procurement plans. If consensus is not reached, SDG&E should file a separate workshop report by February 15, 2003, detailing areas of agreement and disagreement among parties for our further consideration.

IX. Risk Management

1. Timing Risks – Exercising Caution and Allowing the Market to Develop

We expect each utility to utilize a procurement strategy that fulfills its procurement needs over time (rather than signing contracts for its entire residual net short energy needs in a short condensed time-frame). Each utility shall update its procurement plan to include details of how the utility plans on procuring over a period of time.

2. Supply Risks – Diversifying the Supplier Portfolio

The utilities shall seek to secure diversity in counterparty representation within its contract portfolio; not all contracts should be with one supplier or limited set of suppliers. Updated procurement plans shall discuss how the utility will ensure that it contracts with a variety of counterparties. In addition, utilities should not rely on generation based on only one fuel source. We encourage the utilities to devise a strategy for procuring generation from a variety of fuel resources. Utilities should also address their use of demand reduction products.

3. Price Risks – Establishing Risk Tolerance Level

PG&E and SDG&E state in their testimony that their risk management policy would be dependant upon an unspecified level of acceptable cost for protection against price spikes. Edison discusses its current risk management policy, but does not provide its target level of risk tolerance (described as acceptable costs to avoid price spikes). In their filed procurement plans, the utilities decline to recommend or quantify a level of price risk tolerance. Determining this cost is critical for the utilities to be able to file complete procurement plans that can be approved by this Commission.

Our objective is to create a procurement policy that ensures the lowest possible reliable rates. The utilities have not filed any real details for the level of consumer price risk that should be considered acceptable.

It is clear that in order to develop coherent procurement strategies, the utilities must be able to evaluate potential transactions in terms of the costs of the transaction against the elimination of potential price risk. Given the lack of record, we require the utilities to provide a level of consumer risk tolerance, along with a justification for the level they propose in their procurement plan application. In approving the utility procurement plans, we will accept or modify their proposed consumer risk level. The utilities shall use the approved risk level in preparing their updated procurement plan for the following quarter.

On a parallel track, the Energy Division shall retain a consultant to gather additional information regarding appropriate consumer price risk levels. We expect that the consultant will issue a final report by late 2003.

4. Reliability Risks

Closely related to the concept of determining the appropriate level of price risk in each utility's procurement strategy is determining the appropriate degree of reliability risk. Reliability risk is concerned with the availability of sufficient energy to meet expected demands, particularly during peak periods. At its extreme condition, reliability risk recognizes the possibility of there being insufficient energy, at any price, available to meet demand.

In their previous filings where the utilities performed calculations of their residual net short, the utilities had to develop forecasts of a number of key inputs. These included such factors as what type of weather year, forecasts of demand, and the expected availability of utility retained generation, DWR and other contracts, and the availability of additional energy in the Western market. While many of these calculations were sufficient to develop the residual net short and to start developing procurement strategies, they may not have been as useful as they should have been in determining the reliability of their procurement strategies, particularly under stressed system conditions (such as abnormally hot weather or above normal plant outages).

Therefore, we will direct the utilities, as part of their filings, to address the underlying reliability risks inherent in their procurement strategies under varying degrees of stressed system conditions.

X. Procurement Plan Process

As discussed above, we require each utility to file two sets of procurement plans: short-term procurement plans and long-term procurement plans. These are discussed in turn below.

A. *Short-term Procurement Plans*

In D.02-08-071 we authorized the utilities transitional procurement authority to cover up to 100% of their low-case forecast scenario RNS needs (a conservative estimate) beginning January 1, 2003. In an ideal world, our transitional procurement authorization would have covered all short-term needs and this decision would cover only long-term procurement planning. We recognize two realities, however:

- that there may be a gap between the authority we granted in D.02-08-071 and the utilities' actual RNS needs beginning January 1, 2003, and
- that there is not enough time between the issuance of this decision and January 1, 2003 for the utilities to present thoughtful and realistic long-term procurement plans and have them approved by the Commission before beginning procurement under those plans (to ensure compliance with AB57 requirements).

For these reasons, we find it necessary for the utilities to first file a short-term procurement plan, on November 12, 2002, to cover their updated RNS needs. The short-term plan should cover only plans for activities to procure electricity in 2003 (though the actual power bought or contracted for in 2003 may cover needs for up to five years). The short-term plans may utilize all products and authorities granted within this decision, and should include all required elements of a procurement plan described in Section IV above, along with relevant information discussed in Sections V through IX. In the short-term plan, we do not expect the utilities to undertake an exhaustive procurement planning process that takes into account all possible resource options. The short-term process will necessarily be narrowly focused and therefore only include a subset of resources (Section V) or transaction types (Section VII), for example.

We intend to issue a decision approving or modifying the utilities' short-term procurement plans by the end of 2002. To meet that deadline, we adopt an expedited procedural process that provides for comments and protests on December 2, 2002, reply comments from all interested parties on December 6, 2002, and preparation of a draft decision for the Commission's consideration at the December 19, 2002 meeting.

Once a utility's short-term procurement plan is approved, all transactions entered into in compliance with the procurement plan should be filed for tracking purposes in a quarterly advice letter with the Commission Energy Division. The advice letter should include all information in the adopted master data request in Appendix B. Filing of an advice letter presumes compliance with the adopted plan, and therefore the Energy Division should not have to issue resolutions approving the transactions.

If, however, a transaction is outside of the approved short-term procurement plan, the utility should file an expedited application to gain Commission approval for deviation from the approved plan.

B. *Long-term Procurement Plans*

While we view the short-term procurement plans described above as a stopgap measure to ensure that there are no unmet needs and the lights stay on beginning January 1, 2003, we believe that the bulk of our efforts going forward should be focused on putting a process in place to meet the long-term (up to 20-year) procurement needs of California electricity consumers. Indeed, most of the description of procurement plans in Sections V through IX above is focused on long-term procurement needs.

To that end, we require that the utilities file, no later than February 15, 2003, a long-term procurement plan to cover anticipated needs between 2004 and 2023. Thus, contract terms of up to 20 years may be authorized. This long-term procurement plan should include a mix of all of the resources and products authorized in this decision. In particular, the long-term plan should explicitly include all of the resources covered in Section V of this decision. If a utility chooses not to plan to procure any of the resources in Section V, the long-term plan should include a detailed description of the reasons for excluding those resources.

Interested parties should file comments on the utilities' long-term procurement plans by March 10, 2003, with reply comments due by March 20, 2003. This should enable the Commission to issue a decision approving the long-term plans by April 15, 2003, in compliance with the AB57 timeframes.

As with the short-term procurement process, utilities should file a quarterly compliance advice letter within 15 days after the end of each quarter detailing all transactions in compliance with the adopted plan. If a transaction falls outside of the approved plan, the utility should file an expedited application as detailed in Appendix C.

Thereafter, we will require the utilities to file semi-annual procurement plan updates on August 15, 2003, February 15, 2004, and so on, until this requirement is modified or eliminated by a subsequent Commission decision. Utilities may also amend their long-term procurement plans at any time through the filing of a separate application.

XI. Standards for Utility Behavior

The Commission also needs to adopt standards and criteria that address the behavioral conduct of the utility and its personnel. The exhibits prepared by the utilities show that there were only a limited number of disallowance decisions made by the Commission during the seventeen year period from 1980 to 1996 for the three utilities and that the majority of these decisions and dollar adjustments involved affiliate transactions. The Commission has affiliate transaction rules in place to guard against affiliate abuse, but these rules were designed for the regulatory world of AB 1890, not today's market structure. Therefore, we will place a two-year moritorium on all affiliate procurement transactions, beginning January 1, 2003, to allow for a careful reexamination and appropriate modification of our affiliate rules.[11]

The abuses of energy companies during California's energy crisis are still being uncovered and investigated. The magnitude of these abuses clearly affirms the need for strong standards and vigilant oversight of energy procurement practices and the need for the Commission to investigate and act at

[11] In R.01-01-001, we are beginning the process of reexamining the affiliate rules and will consider the procurement authority granted here into account in our reexamination.

any time if standards are violated. The minimum standards of behavior we adopt for the respondent utilities are as follows:

1. Each utility must conduct all procurement through a competitive process with only arms-length transactions. Transactions involving any self -dealing to the benefit of the utility or an affiliate, directly or indirectly, including transactions involving an unaffiliated third party, are prohibited.
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.
3. In filing transactions for approval, the utilities shall make no misrepresentation or omission of material facts of which they are, or should be aware.
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 post standard.
5. The utilities shall not engage in fraud, abuse, negligence, or gross incompetence in negotiating procurement transactions or administering contracts and generation resources.
6. 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.

While we will review contract administration and economic dispatch issues on a timely and regular basis, there is no time limitation on our investigation of the violation of any other standard above. The Commission retains full authority to investigate when a violation is discovered and to effect any and all remedies available to us. This is consistent with proposed Section 454.5(h)

XII. Ratemaking Treatment for Generation Procurement

As set forth in the ACR dated April 2, 2002, the objectives in developing an interim cost recovery procurement mechanism are to:

- improve the ability of the respondent utilities to meet their obligation to serve their customers' electric loads;
- assure just and reasonable electricity rates;
- enhance the financial stability and creditworthiness of respondent utilities;
- diminish the need for after-the-fact reasonableness reviews of procurement purchases;
- ensure the timely recovery in rates of procurement costs in order to support the credit of the utilities that function as load serving entities; and
- pursue our mandate to promote the development of renewable generation in California.

The ACR finds that "Edison's proposal is generally consistent with prior cost recovery mechanisms for PPs and it is therefore a familiar and understood approach to industry, advocates, and the financial community." The respondent utilities propose various cost recovery mechanisms to comply with the objectives and the preferred method. They indicate that a quick review and timely cost recovery process are critical to their financial stability and creditworthiness that would avoid any accumulation of large under-collections of purchased power costs.

The purpose of balancing accounts and timely recovery of procurement costs are intertwined in the AB 57. Proposed Section 454.5 (d) (3) contains certain procurement cost recovery objectives and provisions for the Commission to implement. The relevant part states that the Commission shall:

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

Parties also state that their proposals are in harmony with the intent of proposed AB 57. The cost recovery mechanism proposals from PG&E, Edison, SDG&E, ORA and TURN are enumerated below.

A. *Parties Proposals*

1. Parties Balancing Account Proposals

PG&E	SDG&E	EDISON	ORA	TURN
Purchased ElectricCommodity Account (PECA)[12] Consisting of two sub-accounts:(1) It tracks monthly PG&E's costs and associated revenues and (2) It tracks DWR's revenues and costs.	Procurement Cost Adjustment Mechanism (PCAM) that tracks actual monthly energy procurement commitments and ancillary services costs and related revenues except for URG[13] costs.	Existing Settlement Rates Balancing Account (SRBA) [14] that tracks the difference between "Settlement Rates"[15] revenues and "Recoverable Costs."	Energy Cost Adjustment Clause (ECAC)[16] Type balancing account that tracks billed revenues from established fuel and purchased power forecast rate and actual costs.	Balancing Account for fuel and procurement related costs including operations and maintenance (O&M)[17] and capital costs for power from URG.

[12] The Commission adopted PECA in the Post-Transition Period Electric Ratemaking (PTER) decisions D.99-10-057 and D.00-06-034.

[13] SDG&E has proposed in Application (A.) 02-01-015 to establish Utility Retained Generation Recovery Account (URGRA) required by D.01-12-015 for a permanent cost recovery mechanism. (SDG&E's Supplemental Testimony Exhibit 70)

[14] Resolution E-3765, dated January 23, 2002 established the SRBA after Edison filed Advice Letter 1586-E, dated November 14, 2001 to implement the Agreement provisions.

[15] "Settlement Rates" is defined in the Agreement approved by the United States District Court on October 5,2001 (Exhibit 10,p. 9, ¶ (w) and for "Recoverable Costs" see p. 8).

2. Scope of Included Expenses[18]

Types of Cost	PG&E[19]	SDG&E[20]	EDISON[21]	ORA
URG Fuels	YES	NO	YES	YES
QF Contracts	YES	NO	YES	YES
Inter –Utility Contracts	YES	NO	YES	YES
ISO Charges Less RMR[22]	YES	NO	YES	YES
Irrigation District Contracts	YES	N / A	N / A	YES
Bilateral or Forward Market Purchases	YES	YES	YES	YES

[16] ECAC where fuel and purchased power costs used to be tracked prior to the electric deregulation.

[17] TURN would still want O&M and capital costs to be set in the general rate case (GRC) but tracked with fuel and procurement costs for ease of comparison between costs of different resources with different ownership possibly in sub-accounts of the balancing account.

[18] The cost items proposed by PG&E, SDG&E and Edison for their procurement balancing accounts shown below are currently recorded in various Commission authorized balancing accounts that track energy related costs and their fixed costs.

[19] PG&E proposes to establish PECA rate based on monthly forecast of these costs similar to core gas procurement rate approved in D.97-10 065

[20] In A.02-01-015, SDG&E has requested a new Electric Energy Commodity Charge (EECC) or rate, based on majority of those costs excluded from the PCAM. SDG&E requests two annual adjustments to EECC rate, a self adjust "balancing rate" and "energy rate adjustment component" that reflects the difference between the annual succeeding forecast and prior forecast of costs. *Id.*

[21] Edison currently records these costs in the Power Purchased Balancing Account (PPBA), ISO Balancing account, Net Short Procurement Cost Account, and Native Load Balancing Account (fuel costs). These are part of the SRBA that calculates monthly "Surplus" allowed by the Agreement and being applied to the PROACT. Edison further proposes to change the ratemaking for these costs by establishing a Fuel and Purchased Power (F&PP) balancing account and an F&PP rate, based on annual forecast of these costs after December 2003 or the "Repayment Period."

[22]Reliability Must- Run (RMR) revenues from plants required by the ISO for reliability.

Credit and Collateral	YES	YES	YES	YES
Ancillary Services	YES	YES	YES	YES

3. Edison Treatment of Pre and Post December 31, 2003

Edison proposes three approaches to record and recover costs associated with its RNS. Prior to its 2003 GRC decision, RNS costs would be recorded in the SRBA until new revenue requirements are established by the GRC decision to recover base costs and F&PP costs. Base costs include distribution, generation O&M, administrative and general (A&G), depreciation, return and taxes. After the GRC decision but before the PROACT Repayment Period (September 1, 2001 to December 31, 2003), the authorized revenue requirements would be recorded in the SRBA as Recoverable Costs. After the Repayment Period, Edison proposes that new revenue requirements be established for the base and F&PP costs and their associated rates. An F&PP balancing account would be created to track procurement rate revenues based on the established F&PP rate and recorded actual costs.

4. Rate Adjustments and Amortization Periods

Utility	Rate Adjustment and Amortization Period Proposals
PG&E	Proposed to establish the initial PECA rate by advice letter based on costs associated with the approved procurement plan. Proposed to adjust rates monthly based on changes between monthly forecast of procurement costs and prior month's balancing account balance. Monthly rate adjustments will be by advice letter process similar to current core gas procurement charge (CGPC).
SDG&E	Proposed to establish PCAM rate[23] by advice based on procurement costs associated with its approved procurement plan. Proposed to adjust rates to reflect changes between monthly forecast of procurement costs and prior month's balancing account balance. Edison also proposed to adjust rates by advice letter if the balance in the PCAM reaches 5%[24] of the combined revenues in the PCAM and URGRA in view of proposed AB 57 trigger mechanism.
EDISON	Proposed to adjust Settlement Rates if at the end of any month the balance in its approved Rate Change Tracking Account (RCTA)[25] reaches the 5% (trigger) of its prior year recorded generation revenues excluding DWR revenues or $280 million and reflect an updated procurement cost estimates by advice letter filing.[26] Edison states that its proposal reflects the Agreement[27] with the Commission and AB 57 proposed trigger mechanism. Edison proposes to establish Fuel and PP rate [28] and terminate the Settlement Rates after the Repayment Period.
ORA	Proposed that procurement cost forecasts be established annually by expedited application to be approved within 75 days of filing. ORA would adjust rates when the balancing account balance exceeds the 5% trigger proposed by AB 57 and amortized at a balancing rate.

[23] SDG&E proposed that this rate be a part of its total EECC rate. It plans to modify its EECC tariffs at the time the initial PCAM rate is established by advice letter. The PECA rate will consist of an energy rate and a balancing rate. Each will adjust monthly.

[24] Proposed Section 454.5 (d)(3) states in part that until 2006, the Commission shall ensure that any undercollection or overcollection in the power procurement balancing account does not exceed 5 percent of the electric corporation's actual recorded generation revenues for the prior calendar year excluding revenues collected for the DWR.

[25] RCTA tracks the difference between Stabilized DWR charges and the sum of Edison's Net Short Procurement Costs and current DWR charges.

[26] Edison is proposing that the filing be effective 60 days after the advice letter is filed.

[27] Edison plans to increase or decrease Settlement Rates effective January 1, 2003 consistent with the language in the Agreement and the outcome of forecast revenue requirements adopted in this proceeding and the concurrent DWR revenue requirement proceeding.

[28] The rate revenues and actual costs are tracked in the F&PP balancing account. Edison proposed that the balance in the account be trued up annually but its review takes place semi-annually by filing an application. Edison requests a similar rate adjustment trigger mechanism during the Repayment Period to apply after Settlement Rates termination.

B. *Discussion*

1. Balancing Account and Related Issues

There are several ratemaking issues raised by parties. These include a process to establish a procurement rate for fuel and purchased power-related costs, tracking procurement cost rate revenues against actual recorded costs in a balancing account, adjusting procurement rates based on monthly procurement forecasts and prior balancing account's balance or according to a balancing account balance threshold or specific amount, and adjusting Edison's Settlement Rates based on the language in the Settlement Agreement between Edison and the Commission. We have strong concerns with utilities' proposals to set rates beginning January 1, 2003 and to institute monthly rate adjustments.

First, Edison proposes to adjust Settlement Rates in this proceeding. The major factor contributing to Edison's proposal for a rate increase or decrease effective January 1, 2003 is not before us in this proceeding but in the DWR revenue requirement proceeding in A.00-11-038 et al. As a threshold issue, we do not know the magnitude of the change in DWR's revenue requirement for 2003 compared to 2002 that would be allocated to Edison. In addition, this proceeding focuses solely on RNS that DWR would not be able to procure in 2003 because of prohibition by law and not on the rate impact due to an increase in DWR's overall revenue requirement. We also do not consider here the operation of the SRBA[29] and the related PROACT. Thus, we will not grant Edison's request for a rate increase or decrease effective January 1, 2003 because

[29] Edison requests the Commission to rule in this proceeding where and when the entries in its SRBA and PROACT should be reviewed. We deny Edison's request without prejudice. Edison is free to choose an appropriate vehicle after the recovery of its PROACT for the Commission to review these entries.

this proceeding is not the appropriate forum to set rates. Edison's request is denied without prejudice.

Second, we will not adopt a process to establish procurement rates by January 2003 at this time. We recognize that we must establish rates, but there are many factors that we must consider and not all of these are determined at this time. We do not yet know the size of RNS energy the utilities will need to procure in 2003 and their associated costs. In addition, existing rates collected from customers include surcharges. The embedded energy rate and the surcharges are used to determine whether end-use customer retail rates must be increased because of the impact of DWR's revenue requirements and the rate remittances to DWR for power charges, which customers do not see on their bills. In addition, in A.00-11-038 et al. we are establishing a bond charge for the costs of issuing bonds related to DWR's PPs. We must determine whether existing rates and surcharges contain enough "headroom" as the Commission has used this term to absorb the expected RNS costs, the DWR charges, and any other provisions established by this Commission. Until the Commission considers the impact of all of these rate elements, we cannot determine the current allocated specific components of present rates for fuel and purchased power rates for PG&E, SDG&E, and Edison. Therefore, we deny the utilities' requests for fuel and purchased power rates at this time. However, we firmly intend to establish a process to track all necessary costs and to make the utilities whole, as appropriate. We now turn our attention to the remainder of the ratemaking issues raised by parties.

The procurement cost recovery proposals by PG&E, SDG&E, Edison, and ORA reflect many aspects of the provisions of AB 57 to achieve the objective of timely recovery of procurement costs incurred for an approved procurement plan. The parties agree that a balancing account is needed to track procurement costs. They differ however, as to when and how often rates should change, what should trigger or be included in rate changes, the time period during which rate adjustments should be amortized, and what process should be used. PG&E, Edison, and ORA agree there should be a balancing account to track fuel and purchased power revenues against actual recorded costs. They also agree on the types of cost to be included in the account. SDG&E, however, proposes to exclude URG costs from its account. Edison proposes to delay its F&PP balancing account until after the Repayment Period or December 31, 2003. PG&E wants to establish its PECA by the beginning of 2003. The three utilities have different names for their balancing accounts. For the sake of uniformity and clarity, PG&E, SDG&E, and Edison should refer to their new balancing accounts as the Energy Resource Recovery Account (ERRA) instead of the names they have proposed. We adopt ERRA because it would account for the cost of different types of energy resources. In addition, a common account name for tracking energy costs would allow for different types of comparisons among utilities in the area of types of cost inclusion, tariff language, and filings with the Commission, similar to the ECAC proceedings, which were used for this purpose prior to electric restructuring.

A comparison of the ECAC and the recommended ERRA follows:

DESCRIPTION	ECAC	PROPOSED ERRA
Major Cost Items Provisions Recorded or now Proposed	Gas, oil, coal, nuclear fuels[30], and their inventory carrying costs, and water for power. Purchased power and Department of Energy (DOE) fees.	URG fuels; QF, Bilateral, Irrigation Districts, and Inter utility, Contracts. Power Purchases, ISO, Credit / Collateral, and Other Items approved
When Set Rates Adjust	Annual Revision of Forecasts including balancing account amortization	Semiannual Revision of Forecasts and Specific Amount Trigger Filing
Balancing Account Amortized Length	12 Months	12 Months and 90 Days for triggers
Rate Adjustment Triggers and Review	Annual Revision of Forecasted Costs and Review	Semiannual Revision of Forecasted Costs and Review.
Process	Application	Application

PG&E, Edison and ORA want similar types of cost items to be included in their balancing account proposals or the new ERRA. TURN supports the concept of a balancing account for fuel and purchased power costs and also suggests that O&M and capital costs for power produced from URG should be tracked with these for ease of comparison between costs of different resources and different ownership. We find merit in this idea but we do not adopt it at this time.

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[30] For PG&E the total amount for owning and operating Diablo Canyon (DC) was included in its ECAC in D.88-03-067.

We adopt the ECAC type-balancing account proposed by PG&E, Edison, and ORA. Edison should not delay establishing its new ERRA proposal because of its existing ratemaking structure. Edison's ERRA should eliminate the need for the ISO and PP balancing accounts. The Native Load balancing account should be amended to exclude all URG fuel costs since they are now to be included in the ERRA. We reject SDG&E's proposal to exclude URG costs from its new ERRA and agree with ORA that these should be included. Accordingly, SDG&E should modify its proposal to include URG costs for the new ERRA. We support this approach since it would facilitate energy cost comparison among utilities and assist us to track variable energy related costs, and establish energy revenue requirement and associated rate in the near future.

Below, we describe the semiannual update process that we establish for fuel and purchased power forecasts and the ERRA mechanism.

Date	Description
Beginning January 2003	Track 2002 fuel and purchased power authorized revenue requirements against actual recorded costs in the ERRA.
February 15, 2003 August 15, 2003	File applications proposing to establish semiannual fuel and purchased power forecasts and true up 2002 fuel and purchased costs.
February 15, 2004	Forecast of Fuel and purchased power applications due for revision and review of contract administration, URG expenses and least-cost dispatch.

Because we establish an update process, PG&E's and SDG&E's proposals to change forecast of procurement costs monthly and adjust rates to reflect the difference in the forecast and prior month's balancing account balance by advice letter process similar to monthly changes to gas core procurement charge are denied. Edison has not proposed monthly rate changes but would propose a rate change if at any month the balance in its Rate Change Tracking Account reaches a certain threshold. Edison's request is also denied.

We agree with ORA and TURN that we must balance the utilities' need for timely procurement cost recovery with the consequences of frequent rate adjustments on consumer behavior. We recognize PG&E's, SDG&E's and Edison's concern that they can no longer finance a large under-collection for a period of time longer than a month or two and recognize the importance of timely recovery of over or under collections of balancing accounts to their financial health and stability. We must, however, balance these concerns with customer interests. Monthly energy rate changes may significantly impact the bills of combined gas and electric customers since gas procurement charges are already being changed monthly. Gas usage is seasonal. The impact of pricing electricity monthly may not be the same as gas and therefore customer reaction may be totally different from prior experience. We have no analysis or information in this proceeding to allay our concerns.

2. Balancing Account Trigger Mechanism

We adopt ORA's balancing account trigger proposal with the following modifications. PG&E, SDG&E and Edison are to file applications on February 15, 2003 to establish fuel and PP power rates based on their 2003 fuel PP forecasted costs and these should be done semiannually thereafter. The ERRA proceeding should benefit from the quarterly updated information of the procurement plan.

The forecast phase would establish forecast fuel and PP revenue requirements for the three utilities. We recognize that PG&E and Edison propose that their 2003 fuel and purchased power revenue requirements be established and approved in their GRCs. That matter is now to be decided in the forecast phase of this proceeding. GRC applications should be correspondingly amended. The February 15, 2003 filings should include a true -up of actual recorded costs to adopted 2002 revenue requirements.

Prior to these filings, PG&E, SDG&E and Edison are to track the difference between recently approved fuel and PP revenue requirements[31] by the Commission[32] and actual recorded costs in their ERRA. We recognize that the ERRA will capture additional costs incurred for RNS procurement.

We will also establish a "minimum balance" approach for rate adjustments. Instead of changing rates when the recorded balance in the ERRA exceeds or reaches five percent of prior year recorded generation revenues excluding revenues collected for DWR, we direct PG&E, SDG&E and Edison to file expedited applications for approval in 60 days from the filing date when the new ERRA balance reaches four percent.[33] The application will include a projected account balance in 60 days or more from the date of filing depending on when the balance will reach the five percent threshold. The application will also propose an amortization period for the five percent of not less than 90 days to

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[31] Edison and SDG&E should remove from the 2003 SONGS ICIP rate the fuel related rate or cost for tracking in the ERRA against actual recorded fuel cost.

[32] See Appendix A

[33] By the time rates are adjusted under Edison proposal the ERRA balance may exceed the five percent trigger in violation of proposed AB 57. The minimum balance approach allows for processing time and insures compliance with the proposed law.

ensure timely recovery of the projected ERRA balance. It should also include allocation of the over and under collection among customers for rate adjustment based on existing allocation methodology recognized by the Commission. Customer notice should be sent as soon as the application is filed for a rate increase or decrease.

We do not expect our four percent threshold trigger filing to require immediate revenue requirement adjustment in 2003 because gas prices have stabilized in 2002 compared to 2001 and we expect this trend to continue in 2003. Since revenue collected for DWR is excluded from the calculation of AB 57 trigger mechanism, we are also excluding it for the purpose of determining the trigger filing discussed above.

We will use the semiannual applications filed on August 15, 2003 to review the reasonableness of URG expenses, contract administration, and least-cost dispatch operations and to verify the entries in the ERRA.[34]

Comments on the Proposed Decision

The alternate decision of Commissioner Peevey in this matter was mailed to the parties in accordance with Rule 77.6 (d) of the Commission's Rules of Practice and Procedure. Comments should be filed by October 17, 2002 with reply comments filed by October 21, 2002.

Findings of Fact

1. Edison, PG&E, and SDG&E are the respondent utilities in this proceeding.

[34] In D.02-04-016 issued April 4, 2002, the Commission directed that Edison's and SDG&E's purchased power costs and PG&E's nuclear generation costs should be subject to reasonableness review. (See Conclusions of Law 15, 25, and 28.)

2. Both the Commission and the Legislature have clearly expressed the intent to return the respondent utilities to full procurement on January 1, 2003.

3. This decision adopts the regulatory framework under which Edison, PG&E, and SD&GE shall resume full procurement responsibilities on January 1, 2003.

4. Today, an average of 90% of bundled service energy requirements at any given time are provided by existing DWR and utility contracts as well as utility retained generation.

5. In D.02-08-071, the Commission recently granted the utilities authority to enter contracts through DWR to cover their conservatively-projected procurement needs in 2003-2008.

6. While we share the goal of Edison and PG&E regaining an investment grade rating, this is not a necessary precondition to resuming procurement. SDG&E is already an investment grade utility.

7. Many companies in the energy industry today do not have an investment grade credit rating and are able to conduct business.

8. Several companies state they would enter contracts with Edison and PG&E.

9. Both Edison and PG&E have strong cash positions and cash flow, arising from current rates being above current operating costs. Edison and PG&E will be operating in a regulated environment with ratemaking mechanisms that ensure timely and stable cost recovery.

10. Edison currently meets the rating agencies' criteria for an investment grade utility and is on the verge of regaining its investment grade rating. The ratemaking treatment adopted here supports that effort.

11. PG&E is presently in bankruptcy but under the Commission's proposed Plan of Reorganization, PG&E will be able to quickly emerge from bankruptcy as a creditworthy entity, because it will meet the rating criteria for investment grade.

12. Aglet provides convincing evidence that Edison's and PG&E's recent recorded earnings, cash positions, and anticipated cash flows compare favorably with the collateral and procurement amounts required, even using the high estimates of Exhibits 139C and 140C.

13. We find Edison's and PG&E's procurement needs in 2003 are well within their ability to finance.

14. The remaining residual net short requirements of Edison and PG&E for 2003 can be met through a combination of directly contracting with wholesale energy suppliers, purchases in the energy markets administered by the ISO, and purchases of demand-side resources, including distributed and self-generation.

15. Collateral, in the form of bank letters of credit or other financial instruments are currently available to both companies.

16. The Legislature has passed, and Governor Davis has signed, two pieces of legislation with significant implications for renewable generation procurement by the utilities. These measures are SB 1038 and SB 1078.

17. We will direct the utilities to submit, with their short-term procurement plans on November 12, 2002, a report on the status of their procurement under the renewable generation mandate of D.02-08-071. In this way, we can monitor the utilities' documentation their plans for meeting the procurement required, including what has been accomplished and what remains to be done.

18. It is reasonable to request parties with information regarding the contract status of existing renewable facilities to file a report to provide the Commission

with an update on negotiations with the utilities. We should also request the CEC, to the extent it has information, to provide an update report within 15 days of the effective date of this order, on the status of those potential new facilities it has previously identified, and the extent to which those facilities are engaged in the transitional procurement process.

19. Interested parties should address in comments on January 6, 2003 and reply comments on January 13, 2003, their recommendations on procedural process and schedule for implementing SB 1078.

20. It is reasonable to require utilities to procure both short- and long-term energy and capacity needs from a variety of resources, including conventional generation, renewable resources, distributed and self-generation, demand-side resources, and transmission.

21. It is reasonable to require utilities to meet a reserve requirement, as part and parcel of their obligation to serve.

22. In order to reduce price volatility and risk, it is reasonable to limit spot market purchases to no more than an average of 5% of the utility's annual energy resource needs.

23. Though we state a preference for the adoption of an incentive mechanism to allow utilities to balance procurement risks and rewards, we do not have enough information to adopt such a mechanism at this time.

24. It is reasonable to place a two year moritorium on all affiliate procurement transactions, beginning January 1, 2003, to allow for completion of the Commission's reexamination in R.01-01-001 of affiliate rules and any appropriate modifications affecting procurement activities.

25. We will not adopt a process to establish procurement rates by January 2003 as there are many factors that must first be considered and not all of these

are determined at this time. Until the Commission determines whether existing rates and surcharges contain enough “headroom,” as the Commission has used this term, to absorb the expected RNS costs, the DWR charges, and any other provisions established by the Commission, we cannot determine the current allocated specific components of present rates for fuel and purchased power rates for Edison, PG&E, and SDG&E.

26. We should establish a balancing account for Edison, PG&E, and SDG&E to track energy costs, excluding existing DWR contracts, that includes URG fuels, QF contracts, inter-utility contracts, ISO charges less reliability must-RMR revenues, irrigation district contracts, bilateral or forward market purchases, credit and collateral for procurement purchases, and ancillary services. For the sake of clarity and uniformity each utility should refer to this balancing account as the ERRA.

27. We find that a semiannual schedule for procurement rate adjustments and a 4% balancing account trigger mechanism properly balance the utilities need for timely cost recovery and the consequences of frequent rate adjustments on consumer behavior.

28. We should adopt a semiannual update process for fuel and purchased power forecasts and to review URG expenses, contract administration and least cost dispatch. Utilities should file by application on February 15 and August 15 of each year.

29. Beginning January 1, 2003, the utilities should track 2002 URG fuel and purchased power authorized revenue requirements against actual recorded costs in the ERRA. On February 15, 2003, utilities should file applications that true-up 2002 actual URG fuel and purchased power costs with authorized revenue requirements.

Conclusions of Law

1. The framework we adopt in this decision contains requirements for utility procurement plans, expedited review procedures, and timely cost recovery mechanisms that conform to Assembly Bill (AB) 57's proposed statutory requirements.

2. Consistent with Pub. Util. Code Sections 451, 761, 762, 768, 770 and proposed 454.5(a), the utilities have an obligation to serve.

3. Procurement is a necessary and normal part of utility operations. However, if PG&E believes it requires approval of the U.S. Bankruptcy Court, it should petition the court for approval immediately.

4. We should direct Edison and PG&E to take whatever steps necessary to post the required ISO collateral in order to resume Scheduling Coordination and purchase of the net-short. The utilities should also post the contract and procurement related collateral required to secure resources to meet their load.

5. Edison and PG&E should update their collateral requirement estimations, specifically accounting for ISO security requirements and other contract and procurement related collateral costs in their short-term procurement plans to be filed on November 12, 2002.

6. We should adopt a reserve requirement of 15% for each utility, 25% of which should come from demand response resources.

7. The Commission has authority under Section 701.3 to order procurement in 2003 of any unmet amount of renewable energy ordered in D.02-08-071.

8. The utilities should file each quarter's procurement transactions that conform to the approved plan by advice letter. The advice letter should contain all information in the adopted master data request at Appendix B. The Commission's Energy Division should review the transactions to ensure the prices, terms, types of products, and quantities of each product conform to the

approved plan. Consistent with AB 57, any transaction submitted by advice letter that is found to not comport with the adopted procurement plan may be subject to further review.

9. The utilities should file transactions that do not conform to the adopted procurement plan by expedited application. The procedures for expedited applications are set forth in Appendix C.

10. The advice letter and expedited application processes adopted here meet the standards of proposed Section 454.5(b)(7).

11. The following minimum standards of conduct for the utilities should be:

1. Each utility must conduct all procurement through a competitive process with only arms-length transactions. Transactions involving any self -dealing to the benefit of the utility or an affiliate, directly or indirectly, including transactions involving an unaffiliated third party, are prohibited.
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.'
3. In filing transactions for approval, the utilities shall make no misrepresentation or omission of material facts of which they are, or should be aware.
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 post standard.
5. The utilities shall not engage in fraud, abuse, negligence, or gross incompetence in negotiating procurement

transactions or administering contracts and generation resources.

6. 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.

We should review contract administration and economic dispatch issues on a timely and regular basis. There is no time limitation on our investigation of the violation of any other standard above; the Commission retains full authority to investigate when a violation is discovered and to effect any and all remedies available to the Commission. These standards are consistent with proposed Section 454.5(h).

12. Utilities should file by expedited application for approval in 60 days to adjust rates under an AB57 trigger mechanism if the ERRA balance reaches 4% in excess of prior year's annual fuel and purchased power costs. The application should include (1) a projected account balance in 60 days or more from the date of filing depending on when the balance will reach AB 57's five percent threshold and (2) propose an amortization period for the five percent of not less than 90 days. The application should also include a proposed allocation of the over collection among customers based on our adopted rate design methodology.

13. We should not adopt Edison's proposal to adjust Settlement Rates here as the accounts affected are beyond the scope of this proceeding

14. The ERRA balancing account and the forecast proceedings adopted in this decision comply with the requirements of proposed Section 454.5(d)(3).

15. The AB 57 trigger mechanism application should not be used to refund overcollections until it has been in operation for a full 12 months. Customer notice should be mailed in customers' bills as soon as the application is filed.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company shall resume full procurement on January 1, 2003 under their continuing obligation to serve. The utilities shall take all necessary actions to prepare to do this in an efficient manner.

2. If PG&E believes that it requires approval of the U.S. Bankruptcy Court to resume full procurement, it should immediately petition the court for its approval.

3. The respondent utilities shall file short-term procurement plans on November 12, 2002.

4. Interested parties shall file comments on the November 12, 2002 short-term procurement plans on December 2, 2002 and all interested parties shall file reply comments on December 6, 2002.

5. The respondent utilities shall file a report on the status of their procurement under the renewable generation mandate of Decision 02-08-071 as part of their short-term procurement plan filed on November 12, 2002.

6. All interested parties shall file a proposed procedural process and schedule to implement Senate Bill 1078 on January 6, 2003 and reply comments on January 13, 2003.

7. SDG&E shall sponsor, in coordination with the other utilities, an all-party workshop to develop an incentive mechanism proposal. If consensus is reached, the proposal should be filed in each utilities' long-term procurement plan. If consensus is not reached, SDG&E should file a workshop report containing areas of agreement and disagreement by February 15, 2003 for our further consideration.

8. The respondent utilities shall file long-term procurement plans on February 15, 2003. Those long-term procurement plans should include a mix of all resources contained in Section V of this decision, or explain why reliance on procurement of a particular resource is not appropriate or cost-effective.

9. Interested parties shall file comments on the February 15, 2003 long-term procurement plans on March 10, 2003 with reply comments on March 20, 2003.

10. The respondent utilities shall file each quarter's procurement transactions that conform to their adopted procurement plan by Advice Letter within 15 days of the end of the quarter.

11. The respondent utilities shall file nonconforming transactions by expedited application.

12. The respondent utilities shall comply with the procedure set forth in this decision for the establishment of the Energy Resource Recovery Account balancing account, and the trigger mechanism and forecast filings.

This order is effective today.

Dated ____________________________, at San Francisco, California.

APPENDIX A

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(END OF APPENDIX A)

Appendix B

Adopted Master Data Request for Quarterly Advice Letters

The utilities shall file each quarter's transactions that conform to the approved procurement plan by advice letter. The Advice Letters must contain the following information:

- Identification of the ultimate decision maker(s) up to the Board level, approving the transactions.
- The briefing package provided to the ultimate decision maker.
- Description of and justification for the procurement processes used to select the transactions (e.g., Request for Offers, Electronic Trading Exchanges, ISO Spot Markets)
  - For competitive solicitations, describe the process used to rank offers and select winning bid(s).
  - For other transactional methods, provide documentation supporting the selection of the chosen products.
- Explanation/justification for the timing of the transactions (i.e., product term and rate of procurement)
- Discussion of the system load requirements/conditions underlying the need for the transactions.
- Discussion of how the transactions meet the goals of the risk management strategy reflected in the Commission-approved procurement plan (e.g., achieving lowest stable rates)
- Copy of each contract
- The break-even spot price equivalent to the contract(s)
- An electronic copy of any data or forecasts used by the utility to analyze the transactions.
- Utilities should provide a reasonable number of analyses requested by the Commission or the Procurement Review Group and provide the resulting outputs. Utilities should also provide documentation on the model and how it operates.
- The Commission is not precluded from seeking any other information under the provisions of the Public Utilities Code.

(END OF APPENDIX B)

APPENDIX C

	Procurement Contract Review Process	
Day	Days to Complete Task	Tasks
Days in advance of Application Filing Date	No Limit	Utility internally develops risk management plans for procurement.
0	0	Edison, PG&E, or SDG&E file a complete application that conforms to the quantities, products, terms and conditions we discuss earlier for procurement. The application should demonstrate it meets our standards for approval outlined in this decision. An application may contain all winning contracts from a single RFP solicitation. The application shall include information responsive to the adopted master data request.
30	30	Protests due within 30 days of Application filing.
35	5	Replies to protests due within five business days of protest. (See rules of pp
40	1	A workshop will be held approximately 40 days after the application is filed.
41+	As required	After the workshop, the assigned administrative law judge (ALJ), in consultation with the assigned Commissioner, shall issue a ruling designating whether there are issues of substantial controversy or importance to require the scheduling of hearings. The ruling shall also state whether the ALJ intends to prepare a draft decision which meets the criteria set forth in Public Utilities Code Section 311(g)(2) of being an uncontested matter in which the decision grants the relief requested, a criteria that allows the 30 day public review period to be reduced or waived.
41-59	Less than 20	If the ruling states that the ALJ intends to prepare a draft decision which meets the requirements of Section 311(g)(2), the decision when drafted will be placed on the next Commission agenda.
60+	30+	If the ruling states that the application does not meet the criteria of Section 311(g)(2), a draft decision will be served on parties and subject to at least 30 days public review and comment prior to a PUC vote. If the ruling states that there are issues of substantial controversy or importance to require the scheduling of hearings, such hearings will be held and a proposed decision served on parties and subject to at least 30 days review and comment prior to a PUC vote.
Note: Approval of the contracts will also contain a decision on reasonableness, with prudency of contract administration being at issue over the life of the contract.		

(END OF APPENDIX C)