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Decision 02-10-062 October 24, 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)

(See Appendix A for List of Appearances)

INTERIM OPINION

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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 updating 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 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 low and stable prices. 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 their adopted

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[1] AB 57 was approved by Governor Davis on September 24, 2002.

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

While this decision adopts the utilities' procurement plans filed on May 1, 2002, as modified by later utility filings and this decision, we find they need to be modified prior to January 1, 2003, to reflect this decision, 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 modified short-term procurement plans (for 2003) consistent with this decision November 12, 2002, provide an opportunity for all interested parties to file written comments, and anticipate a draft decision for the Commission's consideration of the modified plans at our 2nd meeting of December 2002.

The regulatory framework we adopt in this decision requires for 2003, the active involvement and expertise of nonmarket participants, through continuing the procurement review group (PRG) process adopted in D.02-08-071 and providing intervenor compensation to those parties eligible to receive the awards

[2] At hearing on July 3, 2002, Edison, ORA, PG&E, and SDG&E represented that while an update filing before January 1, 2003 was necessary, the May 1, 2002 plans constituted the utilities procurement plan submissions contemplated by (then proposed) Section 454.5(a) of AB 57, *See* July 3, 2002 Transcript: page 2299, lines 12-25; pages 2300-2301, lines 23-7; page 2303, lines 8-24; and pages 2306-2308. SB 1976 signed by Governor Davis on September 24, 2002, changes the 90-day procurement resumption requirement of Section 454.5(a) to 60 days. Periodic review and modification of procurement plans are contemplated by Section 454.5(e) of AB 57. PG&E modified its May 1, 2002 plan on September 13, 2002 in response to an ALJ Ruling dated August 27, 2002 and issued in R.01-10-024 to address a deficiency Commission staff discovered in PG&E's May 2002 filings. All three utilities have since modified their plans by updating their residual net-short positions pursuant to Ordering Paragraph of D.02-09-053, the Commission decision that allocated the DWR long-term contracts among the three utilities.

for their work in this process and in the on-going review of procurement advice letters and expedited applications.[3] We make the finding here that participation in the procurement review process discussed above by nonmarket participants who are eligible to request intervenor compensation should be fully compensated because their active participation makes a significant contribution to this proceeding.[4]

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 April 1, 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, and note that this directive was given prior to the passage of Senate Bill

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[3] Parties eligible to receive awards of intervenor compensation in this proceeding are those parties who timely filed a notice of intent (NOI) to claim compensation and have received an administrative law judge ruling on their NOI.

[4] The PRG process is an interim measure while the Commission augments its staff pursuant to the $600,000 as appropriated to the Commission for the purposes of implementing AB 57 and engages an independent consultant or advisory service to evaluate risk management and strategy as authorized under proposed Section 454.5(f).

(SB) 1078, under the mandate of Pub. Util. Code Section 701.3 (Section 701.3).[5] 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
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> (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 January 8, 2002. SDG&E and PG&E filed their proposals on November 21, 2001

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

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.

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 2nd 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.[6] 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.

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,

[6] 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).

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 their obligation to serve.

In this section, we address the utilities' capability to meet their obligation to serve. Pursuant to the Proclamation issued by the Governor of the State of California on January 17, 2001, SB7 and AB1X 1, the state stepped forward in early January and February 7, 2001 to buy power on behalf of end-use customers on an emergency basis.[7] 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, 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 sellers to sell power to the utilities.[8] Since then the state, through DWR, has procured all the residual net short (RNS) requirements directly for utility customers by buying power to meet all energy needed beyond the utilities' own retained generation. DWR has entered into long-term contracts that secure substantial amounts of energy through 2008 and, through the end of 2002, is buying power through the Independent System Operator (ISO). As a result of these actions, we must recognize that the procurement responsibilities Edison,

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

8 While Edison and PG&E have had their credit ratings downgraded below investment grade, SDG&E was and always has been an investment grade utility.

PG&E, and SDG&E will face on January 1, 2003 are substantially less than those they faced in 2000. Today, in excess 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.

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 (SER) (SER) 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 procedural processes 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. After this transitional procurement, the remaining RNS can be met through a combination of directly contracting with wholesale energy suppliers and by making purchases in the spot energy markets administered by the ISO.[9] 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 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,

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[9] Edison and PG&E can still meet their RNS even if they do not procure all the capacity

Footnote continued on next page

both utilities will need to post security amounts as set forth under Section 2.2.3.2 of the ISO's tariff.[10] 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 purchased power and meet contract obligations 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 more transitional authority in D.02-08-071 than either Edison or PG&E requested, we believe the level of collateral requirements that must be posted to resume resource

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authorized in D.02-08-071.

[10] 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.

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 a utility's business and therefore, we do not think bankruptcy court approval is required for PG&E to resume its procurement responsibilities. However, if PG&E believes it requires approval of the U.S. Bankruptcy Court, it should petition for approval immediately.

Edison's available cash totaled $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 totaled $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 modified procurement plan filed on November 12, 2002.

IV. Procurement Plan Elements

The procurement plans filed on May 1, 2002 by PG&E, Edison, and SDG&E vary in depth of detail and comprehensiveness. However, as required by Section 454.5(a), we adopt herein each of the utilities' plans, as modified by this decision and the utilities' more recent filings. We also specify the detail and accuracy of information that shall be needed in order to quickly process and approve transactions to be effective 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 an ongoing 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 and except as otherwise indicated.

When the utilities filed their procurement plans on May 1, 2002, 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 ordered 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.[11]

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. We expect that these reduced requirement will be reflected in future procurement plan updates.

[11] CPUC D.02-09-053 at Ordering Paragraph 8.

AB 57 (codified of Pub. Util. Code Section 454.5(b) enumerates the following elements of a utility procurement 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.

While we adopt the May 1, 2002 procurement plan filings, as modified by this decision and the utilities' more recent filings, we seek updates and modifications to those plans as set forth herein and as provided in Section 454(e). The utilities shall file modified short-term procurement plans on November 12, 2002 to include D.02-09-053 contract allocation and transitional procurement, as well as plans on April 1, 2003. In particular, the utilities shall provide more information on:

- A specific risk management strategy;
- Types of products to be procured over specific time-frames; and
- A target range of quantities to be procured for each product type.

V. Resource Options

In modifying 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 SB 1038. 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.

In making plans to procure a mixture of resources, the utilities should take into account the Commission's longstanding procurement policy priorities –

reliability, least cost, and environmental sensitivity. While each of these priorities is important individually, they are also strongly interrelated. Increased reliability may increase procurement costs. Diversifying the resource mix may meet environmental priorities, but may also increase costs. Thus, the utilities should explicitly address these tradeoffs in their long-term procurement plans.

To assist with that process, we provide the following general guidance:

- Reliability now includes not just traditional concepts like adequacy of reserves, but also a recognition that it should include strategies to:
  - Diversify the generation mix, and reduce reliance on fossil fuels
  - Rebalance the IOU portfolio mix
  - Address the reliability threat posed by aging power plants
  - Address infrastructure security
- Least cost includes mitigating against an over-dependence on fossil fuels whose price is uncertain and can unexpectedly escalate, pulling electricity costs upward. Least cost also includes non-monetary attributes, as well as the time-differentiated production costs of power. Thus, flexible and reliable resource programs with relatively short development lead times (i.e., energy efficiency) can compete with traditional generation options for a place in the IOU resource portfolio. Capturing the time-differentiated costs of power also allows customers that place a higher value on low energy bills than on reliability to have programs available to them that also benefit the system (i.e., demand response programs).
- Environmental sensitivity encompasses not just traditional concerns over air quality impacts and aesthetic aspects of resource development, but a broader recognition that repowering or rebuilding on brownfields should be considered as substitutes to development of greenfields. In addition to the use of

> renewable technologies that must be included in the IOU plans consistent with the law and our mandate, the utilities should also include the environmental effects of repowering or rebuilding.

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 (MW) 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.

The output of a small hydroelectric generation facility of 30 MW or less procured or owned by an electrical corporation as of the date of enactment of this article shall be eligible only for purposes of establishing the baseline of an electrical corporation pursuant to paragraph (3) of subdivision (a) of Pub Util. Code § 399.15. A new hydroelectric facility is not an eligible renewable energy resource if it will require a new or increased appropriation or diversion of water under Part 2 (commending with Section 1200) of Division 2 of the Water Code.

A geothermal generation facility originally commencing operation prior to September 26, 1996, shall be eligible for purposes of adjusting a retail seller's baseline quantity of eligible renewable energy resources except for output certified as incremental geothermal production by the Energy Commission, provided that the incremental output was not sold to an electrical corporation under contract entered into prior to September 26, 1996. For each facility seeking certification, the Energy Commission shall determine historical production trends and establish criteria for measuring incremental geothermal production that recognizes the declining output of existing steamfields and the contribution of capital investment in the facility or wellfield. Facilities must also 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. TURN contends that we have misconstrued the definition of "in-state renewable electricity generation technology." Specifically, "TURN believes that the PD's cited eligibility definitions are modified by Section 383.5(d)(2)(B) of the Public Utilities Code, which allows the Energy Commission to waive the in-state requirement if the facility is located within the WECC transmission system and sells its generation to end-use customers of a California IOU." (Comments of TURN, pp.7-8.) Taking the law of its face, we are not inclined to agree. Pub. Util. Code § 383.5(d)(2)(B) allows for the Energy Commission to award, provided certain criteria are met, Public Goods Charge funds to out-of-state renewable facilities. The code section does not, however, alter the definition of "in-state renewable electricity generation technology." The definition found in Section 383.5(b)(1) remains the binding language for purposes of RPS eligibility. However, we recognize the potential ambiguity of the situation, as well as the potential benefits of allowing out-of-state facilities to contribute to the cost-effective implementation of the RPS program. Therefore, we request that parties, in particular the CEC, provide briefs on this subject, as indicated below. For the purposes of transitional procurement, production from existing out-of-state renewable generation facilities previously selling power to a utility shall be considered part of the utility's baseline only.

In addition to these provisions in SB 1078, we include in our definition of renewable generation, for purposes of compliance with both D.02-08-071 and SB 1078, renewable distributed generation (DG) on the customer side of the meter. Customer-side distributed generation that utilizes the technologies listed in the first paragraph of this Section of the decision is eligible for RPA participation. 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, but only new renewable DG installations are to be credited (existing renewable DG does not count toward the utility's RPS baseline calculation).

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.[12] 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.

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.[13]

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[12] 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.

[13] 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, and the 1% purchase requirement is to be calculated based on 2001 sales figures, including DWR power.

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.

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.[14]

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 2002.

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. No

[14] PG&E and Edison each contend that the Commission's authority to order renewable procurement will be confined to the mandates of SB 1078 on January 1, 2003. We disagree and hold, as CBEA contends, that SB 1078 does nothing to amend or limit the authority and direction conferred by Section 701.3, upon which we relied in ordering interim renewable procurement.

other price benchmark generated by a utility for its own internal use alters in any way the *per se* reasonableness of the 5.37 cents per kWh price.

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 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. We further request, as suggested by CalWEA, that parties provide guidance on the allocation of transmission costs that may arise in the process of RPS implementation. Last, we ask that parties provide briefing on the definition of utility "long-term needs" in Pub. Util. Code § 399.15(a).

Baselines and Targets. As stated above, we direct the utilities to calculate their 1% procurement targets in reference to total 2001 electrical sales, including DWR power. We also need to determine, for purposes of monitoring progress towards the 20% renewable goal, the composition of each utility's portfolio that is presently comprised of renewables. We ask that the utilities, and any other parties with the ability to comment, provide us with 2001 sales figures, the percentage of their present portfolio that is comprised of renewable generation, and their quantitative estimates of the 1% procurement target.

Flexible Compliance and Penalty Mechanisms. 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). Similarly, we are to design penalty mechanisms to be employed in enforcing RPS compliance, and seek parties' comment, with particular reference to successful examples employed in other RPS programs.

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.

Standard Contract Terms and Conditions. Utilities and parties representing renewable developers are particularly encouraged to 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.

Inclusion of Out-of-State Resources. Parties should provide guidance on the legality and potential benefits of allowing out-of-state renewable generation resources to participate in the RPS, particularly as such participation would influence the overall benefits accrued to California by the program, and the potential difficulties in accurately accounting for such power that this participation may involve.

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.

Role of the Procurement Entity. SB 1078 allows for the deployment of third-party contractors in procuring renewable power for sale to utility customers under the RPS. We ask that parties provide guidance on how such entities can best be incorporated, and the extent to which their participation can shield the utilities from risks to their credit ratings, noting that the legislation places such a third-party relationship at the discretion of the utility.

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. Specifically, we are interested to receive comments on the incorporation of renewable DG into the RPS purchases of the utilities.

We request parties through comments on January 6, 2003 and reply comments on January 13, 2003 to provide briefs on the above topics as well as 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 QFs. Utilities should explicitly describe their plans for offering QF contracts in their long-term procurement plans. Distributed and self-generation resources encompass a broad and diverse set of technologies to fit a variety of procurement needs. In addition to providing capacity and energy benefits, they can offer transmission and grid-support benefits that should be included in the utilities' procurement plans.

In their November 12, 2002 short-term procurement plans, utilities should also provide an update on the status of the required standard offer contracts for QFs required in D.02-08-071.

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 and intermediate load 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 if Commission approval occurs in the future.

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 in order to ensure a stable, reliable power system. The ultimate goal is to safeguard the electric system by accounting for forced outages, operating reserves, and regulating reserves, as well as other contingencies. We are aware that the Power Authority is addressing the issue of the appropriate reserve margin in its rulemaking, but will not have a final advisory opinion for the Commission to consider in time for this decision.

In their previous compliance filings in this proceeding, each of the three utilities addressed, albeit without using consistent methodologies, the need to incorporate reserves into their procurement needs. In the interim, however, it is important that the IOUs be responsible for procuring reserves to ensure system reliability. Historically, installed reserves have been 15-18% of system peak load. Therefore, on a provisional basis, we set the reserve level at 15%, subject to consideration of utility specific requirements and reexamination once the Power Authority proceeding comes to a final recommendation. In the November 12, 2002 short-term procurement plans, the utilities should identify and justify a utility-specific reserve level and explain how it will be met and measured.[15]

In addition, we strongly encourage the utilities to meet as much of this reserve requirement as is cost-effective through investments in demand response resources and energy efficiency. We expect to set more specific targets on the level of demand responsive resources required in our demand response rulemaking proceeding (R.02-06-001). Finally, we note that the Demand Reserves Partnership program under contract to DWR may be counted towards the utilities' reserve requirements if approved by the Commission in the future.

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 transactional methods: a competitive bid process, purchases through transparent markets, inter-utility exchanges, ISO markets and utility ownership. Additionally, we authorize the respondent utilities to contract directly with counterparties for short-term products to the extent the utilities make a showing that such transactions represent a reasonable approximation of what a transparent competitive market would produce.

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[15] We understand that there are various ways to count reserves, including, for example, installed capacity, dependable capacity, and other measures to consider historic outage rates as well as de-rating to account for specific resource characteristics. The intention here is to have an explicit explanation of how the utilities are counting the resource, for our future consideration in long-term procurement planning.

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., Bloomberg, Trade Spark, Intercontinental Exchange).
- The procurement plans shall demonstrate that the identified electronic trading exchanges the utility intends to use provide transparent prices.

C. ISO Markets: Hour-Ahead, Day-Ahead (when available), and Imbalance Energy and Ancillary Services

- ISO spot market transactions are authorized to balance system and meet short-term needs.
- Procurement plans shall describe procurement strategies for hedging the utility's overall portfolio risk with ISO spot purchases.
- While we wish to provide utilities with timing flexibility in meeting their residual net short needs, it is not our intention to have the entire RNS met in the spot market. Though we do not set an explicit limit on spot market purchases, utilities should plan to minimize their spot market exposure and should justify their planned spot market purchases if they exceed 5% of monthly needs.
- We authorize the use of a Day-Ahead Market should it become operational.

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 firm energy would otherwise be dumped as surplus into the spot market.

In their comments ORA and PG&E suggest this guideline is too narrow and could be a disincentive to enter into an IUE transaction. Neither suggested an alternative so we will adopt this guideline with the provision that parties may propose more detailed criteria for our consideration in any of the up-dated procurement plans. TURN criticized the guideline as relying upon forecast prices. This is not accurate, because the comparison is to the existing portfolio and other available options, i.e., RFO bids, and so the price would be no higher than would otherwise be paid under the adopted RFO process.

E. Utilities may Provide Showing for Direct Bilateral Contracting for Short-Term Products As an Additional Alternative Procurement Method

- We are receptive to the potential use of bilateral contracts beyond the transactional methods described above for short-term products (i.e., less than 90 days). For the Commission to approve the use of such proposed transactional methods, the utilities updated procurement plans must demonstrate that the transactions for short-term products represent a reasonable approximation of what a transparent competitive market would produce.

F. Utility Ownership

- Utilities may propose to buy or construct generation.

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 the net portfolio price risk 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 amplify net portfolio 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
Authorized Procurement Products

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

Table 1
Authorized Procurement Products

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

Table 1 Authorized Procurement Products		
Transaction	**Description**	**Benefit /Cost**
Ancillary Services	Replacement reserve, regulation up, regulation down, spinning-reserve, non-spinning reserve	Needed to assure system reliability

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 modify its procurement plan on November 12th 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. Modified procurement plans filed on November 12th shall discuss how the utility will ensure that if 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 on November 12th their use of demand reduction products.

3. Price Risks – Establishing Consumer Risk Tolerance Level For Overall Portfolio

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.[16] Determining consumer risk tolerance for the overall portfolio is critical for the utilities.

Our objective is to create a procurement policy that ensures low and stable rates.

The utilities have not filed any real details for the level of consumer risk risk tolerance that should be considered acceptable.

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[16] Consumer risk tolerance defines the price that an average consumer would be willing to pay to reduce the risk of higher prices in the future (i.e., the cost-to-risk tradeoff).

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 modified procurement plans on November 12th. In reviewing the modified utility procurement plans, we will accept or modify their proposed consumer risk level. The utilities shall use the approved consumer risk tolerance 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 risk tolerance levels. We expect that the consultant's final report will be incorporated into our review process for 2004.

We note that we have moved significantly from the situation of recent years where the majority of the consumers' energy needs were procured on the spot market, subject to extreme price volatility. Utilities are now required to retain their remaining generation and use it to serve customers on a cost of service basis as specified in AB 6X. DWR has entered into over 10,000 MW of long term contracts that further reduce the reliance on spot purchases, and reduce potential price volatility. In D.02-08-071, we granted utilities the authority to enter into additional contracts that will further reduce any reliance on spot purchases and reduce consumers' risks of price volatility. Thus, we have moved from a situation with near total exposure to volatile market prices to one where, depending on the level of utility transitional contracting, essentially none of consumers' needs will be subject to market volatility.

Whether we return in the future to having any significant reliance on spot markets will depend in part on developments in the markets themselves and FERC regulations. Future consideration by the Commission of other alternatives to meeting consumers' needs, including demand response and energy efficiency programs, transmission infrastructure additions, and other options such as utility ownership of generation facilities, will also impact the extent to which utilities are to rely on short-term procurement options.

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 November 12th 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 modify its existing plans. In recognition that there is a pressing need to have plans fully modified and in place by January 1, 2003, we distinguish between what should be submitted November 12th as immediately necessary modifications to address short-term procurement and what should be submitted subsequently to address long-term procurement plans. These two categories – short-term and long-term are discussed sequentially below. Anything required for the short-term plan should also be in the long-term plan.

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, and in view of the modifications that we have identified as necessary in the preceding sections of this decision, we find it necessary for each utility to first file what we will call a "short-term procurement plan," that will incorporate the requisite modifications to the extant plans on November 12, 2002, to cover each utility's updated RNS needs. The short-term procurement 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 procurement 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 procurement 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 2nd meeting of December 2002.

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.

We recognize that it may be late in 2003 before we have an adopted long term plan. Therefore, to better ensure the short-term procurement plans adequately reflect the procurement needs of each utility, we afford each utility the opportunity to update its short-term procurement plan by expedited application filing. Before a filing, each utility shall meet and confer with its procurement review group.

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 April 1, 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.

As part of its long-term plan, each utility should identify which procurement proposals will require environmental review, special permits, separate applications or other regulatory procedures or proceedings.

This advice letter process does not supplant the need to follow more traditional procedures for actions that would normally require such procedures. For example, proposals that rely on a budget increase, such as new expenditures for energy efficiency, must be advanced through an application. Similarly, new rate design, such as variations on Time-of-Use rates, require an application. New utility capital projects, such as transmission upgrades and power plants, often require a Certificate of Public Convenience and Necessity. These are only examples. The broader point is that the resource plan and advice letter process do not obviate compliance with other legal requirements.

We plan to review the long-term procurement plans through a full evidentiary process that will conclude with a final Commission decision prior to the end of 2003. To achieve this ambitious undertaking, we adopt the following preliminary schedule:

February 10, 2003	Interested parties file written comments on outlines
February 17, 2003	Prehearing Conference
April 1, 2003	Utilities file long-term procurement plans and supporting testimony
June 2, 2003	Interested parties file testimony
June 23, 2003	All parties file rebuttal testimony
June 30 – July 18, 2003	Hearings
August 8 & 15, 2003	Opening and Reply Briefs
October 17, 2003	Proposed Decision
November 2003	Final Decision

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.

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 moratorium on Edison, PG&E, or SDG&E dealing with their own affiliates in procurement transactions, beginning January 1, 2003, to allow for a careful reexamination and appropriate modification of our affiliate rules.[17] This moratorium is until we complete our rulemaking or two years, whichever date is first. Utilities may propose to include specific affiliate transactions in their procurement plans but these proposals cannot be implemented until the end of the moratorium. Based on comments, we are persuaded that transactions through the ISO that can be demonstrated to include multiple and anonymous bidders are permissible.

[17] 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.

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 any time if standards are violated.

Various commenters have expressed concern that the language at numbered paragraph 6 in the "minimum standards" section of the Proposed Decision confers unfettered discretion on the Commission to modify contract terms. In D.92-11-052, the Commission explained that "[a]lthough the language of GO 96-A [substantively identical to the language at issue] could be read to allow the Commission to modify a contract "at will," in fact, the Commission exercised its authority to modify existing contracts only rarely and under the most extraordinary circumstances." Nonetheless, in response to comments we are revising the disputed language to incorporate the "extraordinary circumstances" standard articulated in D.92-11-052 for when the Commission may exercise its authority to modify existing contracts. 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 existing 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. All contracts must contain substantially the following revision: "in the event of extraordinary circumstances, this contract shall be subject to such changes or modifications by the CPUC as the CPUC may direct."
7. In order to exercise effective regulatory oversight of the behavior discussed above, all parties to a procurement contract must agree to give the Commission and its staff reasonable access to information within seven working days, unless otherwise practical, regarding compliance with these standards.

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 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)[18] 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[19] costs.	Existing Settlement Rates Balancing Account (SRBA) [20] that tracks the difference between "Settlement Rates"[21] revenues and "Recoverable Costs."	Energy Cost Adjustment Clause (ECAC)[22] 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)[23] and capital costs for power from URG.

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

[19] 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)

[20] 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.

[21] "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).

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

[23] 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

Footnote continued on next page

2. Scope of Included Expenses[24]

Types of Cost	PG&E[25]	SDG&E[26]	EDISON[27]	ORA
URG Fuels	YES	NO	YES	YES
QF Contracts	YES	NO	YES	YES
Inter –Utility Contracts	YES	NO	YES	YES
ISO Charges Less RMR[28]	YES	NO	YES	YES
Irrigation District Contracts	YES	N/A	N/A	YES
Bilateral or Forward Market Purchases	YES	YES	YES	YES
Credit and Collateral	YES	YES	YES	YES
Ancillary Services	YES	YES	YES	YES

different resources with different ownership possibly in sub-accounts of the balancing account.

[24] 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.

[25] 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.

[26] 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.*

[27] 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."

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

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[29] 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%[30] 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)[31] 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.[32] Edison states that its proposal reflects the Agreement[33] with the Commission and AB 57 proposed trigger mechanism. Edison proposes to establish Fuel and PP rate [34] 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.

[29] 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.

[30] 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.

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

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

[33] 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.

[34] 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[35] and the related PROACT. Thus, we will not grant Edison's request for a rate increase or decrease effective January 1, 2003 because

[35] 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 purchase power. 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[36], 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 TURN's proposal, but we do not adopt it at this time. We should revisit this proposal when the Commission addresses whether the respondent utilities should build or operate new generation resources.

[36] 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 purchase power 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. ERRA should therefore be a line item in the SRBA. 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 1 SDG&E April 1 Edison June 1 PG&E	File applications proposing to establish annual fuel and purchased power forecasts and true up 2002 fuel and purchased costs.
August 1 SDG&E October 1 Edison December 1 PG&E	Review of balancing accounts, contract administration, URG expenses and least-cost dispatch.

We deny 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 because we establish an update process. 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 in 2003 to establish fuel and purchase power rates based on their 2003 fuel and purchase power 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 proposes that 2003 fuel and purchased power revenue requirements be established and approved in its GRCs. That matter is now to be decided in the forecast phase of this proceeding. PG&E's GRC applications should be correspondingly amended. The 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 purchased power revenue requirements[37] by the Commission[38] 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.[39] 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 ensure timely recovery of the projected ERRA balance. It should also include

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[37] For 2003, Edison and SDG&E should breakout the full ICIP rate into fuel and non-fuel so that fuel related expense is separated from non-fuel in the ERRA and tracked against actual recorded for accounting purposes.

[38] See Appendix D.

[39]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.

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 in mid-2003 to review the reasonableness of URG expenses, contract administration, and least-cost dispatch operations and to verify the entries in the ERRA.[40]

Comments on the Proposed Decision

This proceeding is assigned to Commissioner Lynch and ALJ Walwyn. The proposed decision of ALJ Walwyn in this matter was mailed to the parties in accordance with Public Utilities Code § 311(d) and Rule 77.1 of the Rules and Practice and Procedure.

The major changes to this decision are that it: incorporates Sections IV-X of Commissioner Peevey's alternate decision that was mailed on October 10, 2003; adopts the utilities' procurement plans filed on May 1, 2002 as modified by later

[40] 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.)

utility filings and this decision; revises the proposed decision’s standards of conduct; sets a procedural schedule for the long-term planning phase; adopts more streamlined regulatory processes; states our preference to adopt an incentive mechanism; and makes other changes in response to parties' comments.

Findings of Fact

1. Edison, PG&E, and SDG&E are the respondent utilities in this proceeding.
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, in excess of 90% of bundled service energy requirements are provided by existing DWR and utility contracts as well as utility retained generation.
5. In D.02-08-071, the Commission recently granted PG&E and Edison authority to enter contracts through DWR to cover their projected procurement needs in 2003-2007.
6. While we share the goal of Edison and PG&E regaining an investment grade rating, this is not a necessary precondition to their resumption of their procurement responsibilities. SDG&E was and always has been 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 1078 and SB 1038.

17. We should 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.

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

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

20. 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.

21. It is reasonable to place a moratorium on Edison, PG&E, or SDG&E dealing with their own affiliates in procurement transactions, beginning January 1, 2003, to allow for completion for a careful reexamination and appropriate modification of our affiliate rules. This moratorium will continue until we complete our rulemaking to modify affiliate rules, or for two years, whichever date is first. Utilities may propose to include specific affiliate transactions in their procurement plans but these proposals cannot be implemented until the end of moratorium. Based on comments, we are persuaded that transactions through the ISO that can be demonstrated to include multiple and anonymous bidders are permissible.

22. 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.

23. 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-run 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.

24. 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.

25. We should adopt an annual update process for fuel and purchased power forecasts and another proceeding to again review balancing accounts and rewrite review URG expenses, contract administration and least-cost dispatch. Each utility should file applications on a semiannual basis, as specified in Section XII.

26. Beginning January 1, 2003, the utilities should track 2002 URG fuel and purchased power authorized revenue requirements against actual recorded costs in the ERRA. In their first billings, utilities should file applications that true-up

2002 actual URG fuel and purchased power costs with authorized revenue requirements.

27. The PRG process is an interim one-year measure while the Commission augments its staff and hires an independent consultant or advisory service, pursuant to the contracting authority and $600,000 appropriated to the Commission for the purposes of implementing AB 57.

28. Participation in the procurement review group makes a significant contribution to effective implementation of this decision and parties eligible to receive intervenor compensation awards in this proceeding should be eligible to seek compensation for their work in these groups and in the on-going review of procurement advice letters and expedited applications.

29. No other price benchmark generated by a utility for its own internal use alters in any way the *per se* reasonableness of the 5.37 cents per kWh price adopted in D.02-08-071.

Conclusions of Law

1. We hereby adopt the utilities' May 1, 2002 procurement plans, as modified by later utility filings and this decision. The utilities shall resume procurement no later than January 1, 2003 pursuant to those plans and the provisions of this decision, subject to the modifications ordered by this decision and subject to any prospective modifications pursuant to Pub. Util. Code Section 454.5(e).

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. Electricity procurement is a necessary and normal part of utility operations, conducted in the ordinary course of an electric utility's business. However, if PG&E believes it requires approval of the U.S. Bankruptcy Court to resume its procurement obligations, it should petition the court for approval immediately.

4. Edison and PG&E shall take whatever steps are necessary to post the required ISO collateral in order to resume Scheduling Coordination or procurement of the residual net-short no later than January 1, 2003. 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. 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.

7. 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.

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

9. This advice letter process does not supplant the need to follow more traditional procedures for actions that would normally require such procedures. For example, proposals that rely on a budget increase, such as new expenditures for energy efficiency, must be advanced through an application. Similarly, new

rate design, such as variations on Time-of-Use rates, require an application. New utility capital projects, such as transmission upgrades and power plants, often require a Certificate of Public Convenience and Necessity. These are only examples. The broader point is that the resource plan and advice letter process do not obviate compliance with other legal requirements.

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

11. The utilities shall comply with the following minimum standards of conduct:

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 are the same as our existing 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. All contracts must contain substantially the following language: "in the event of extraordinary circumstances, this contract shall be subject to such changes or modifications by the CPUC as the CPUC may direct."
7. In order to exercise effective regulatory oversight of the behavior discussed above, all parties to a procurement contract must agree to give the Commission and its staff reasonable access to information within seven working days, unless otherwise practical, regarding compliance with these standards.

12. 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).

13. Customer-side distributed generation that utilizes the technologies listed in Section V.B of the decision is eligible for RPS participation. 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.

14. The full output of renewable DG should be credited to meeting the RPS or D.02-08-071 requirements, but only new renewable DG installations are to be credited (existing renewable DG does not count toward the utility's RPS baseline calculation).

15. 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 threshhold 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 during cost of service regulation.

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

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

18. 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 (Edison), Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) 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 a timely and 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 submit modifications to their short-term procurement plans on November 12, 2002 as set forth in the body of this decision, and further update the short-term procurement plans in 2003, when they find it necessary by expedited application filing. Before a filing, each utility shall meet and confer with its procurement review group.

4. All interested parties shall file comments on the November 12, 2002 updated 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 with their modified short-term procurement plan on November 12, 2002.

6. All interested parties shall file a proposed procedural process and schedule to implement Senate Bill 1078 on January 6, 2002 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 each quarter's procurement transactions that conform to their adopted procurement plan by Advice Letter within 15 days of the end of the quarter.

9. The respondent utilities shall file long-term procurement plans on April 1, 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.

10. As discussed above, we require each utility to modify its existing plans. In recognition that there is a pressing need to have plans fully modified and in place by January 1, 2003, we distinguish between what shall be submitted November 12th as immediately necessary modifications to address short-term procurement and what shall be submitted subsequently to address long-term procurement plans. Anything required for the short-term plan shall also be in the long-term plan.

11. The respondent utilities shall file an outline of long-term procurement plan, as detailed in this decision, on February 3, 2002. All interested parties may file written comments on February 10, 2003. A prehearing conference shall be held February 17, 2003.

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

13. This advice letter process does not supplant the need to follow more traditional procedures for actions that would normally require such procedures. For example, proposals that rely on a budget increase, such as new expenditures for energy efficiency, must be advanced through an application. Similarly, new rate design, such as variations on Time-of-Use rates, require an application. New utility capital projects, such as transmission upgrades and power plants, often require a Certificate of Public Convenience and Necessity. These are only examples. The broader point is that the resource plan and advice letter process do not obviate compliance with other legal requirements.

14. 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.

15. The respondent utilities shall comply with the minimum standards of conduct and restrictions on affiliate transactions set forth in this decisions.

16. Edison and PG&E should take whatever steps are necessary to post the required ISO collateral in order to resume Scheduling Coordination or procurement of the residual net-short no later than January 1, 2003. The utilities shall also post the contract and procurement related collateral required to secure resources to meet their load.

17. 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.

This order is effective today.

Dated October 24, 2002, at San Francisco, California.

LORETTA M. LYNCH
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APPENDIX A

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(END OF APPENDIX A)

Appendix B

Adopted Master Data Request for Monthly Advice Letters

The utilities shall file each month'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 month's transactions.
- Discussion of how the month's 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 transitional procurement. Utility also meets with Procurement Review Group (PRG) recommended in the Joint Principles. This group would meet prior to the application being filed and should be convened early on to assess any proposed RFP process before it is implemented. The PRG would meet again to assess the resulting bids, the winning procurement contracts, and reasonableness criteria with each respondent utility. The group would be open to parties designated under our Protective Order to review confidential information and would include representatives of the Commission's Energy Division and ORA as ex officio members.
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 transitional procurement. The application should demonstrate it meets our standard for approval by a showing that entering into the contract(s) should result in favorable and stable rates for ratepayers relative to alternative options. 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. During the transitional period, if the Commission rejects a proposed contract, it will not designate any alternative procurement choices.		

(END OF APPENDIX C)

APPENDIX D
Page 1

	PACIFIC GAS AND ELECTRIC COMPANY				
				Where to	**be Reviewed**
PG&E	**D.02-04-016**		**AL 2233-E**	**and Adjusted**	
	Adopted ($ Millions)		**AL Update Approved ($ Millions)**	**Procurement OIR**	**GRC**
Fossil & Hydro - 13,100 GWH +	**628**		**666**		
Fossil (~1,100 GWH)	149		168		**xxx**
Fuel	89		89	xxx	
Hydro (~12,000 GWH)	387		406		**xxx**
Fuel	3		3	xxx	
Diablo - 17,200 GWH	311		379		**xxx**
Fuel	82		82	xxx	
Purchased Power (7-'01--6-'02)	**1830**		**1830**		
QFs - 20,234 GWH	1545		1545		
Fuel - Gas & Fixed K prices	1028		1028	xxx	
Adm.	517		517	xxx	
FF&U	20		20		
Bilaterals (~ 4,885 GWH '01)	170		170	xxx	
& Others (7-'01 -- 6-'02, various GWH)					
Anc.Services (Grid Mgmt.Chgs.)	94		94	xxx	
+More Ancillary Services of D.02-03-058	25		25	xxx	
EETA /1	30		30	xxx	
Grand Total URG	**$2,906**		**$3,012**		
Residual Residual Net Short				xxx	
/1 EETA (Elec. Energy Transaction Adm. Costs include costs of purchasing elec. from market, contracts					
'and managing energy portfolio.					

APPENDIX D
Page 2

	SAN DIEGO GAS AND ELECTRIC COMPANY				
SDGE	**D.02-04-016 ($ Millions)**	**AL 1403-E Approved**	**Where to be Reviewed and Adjusted**		
Generation - 3500 GWH					
Operating Expenses			Procurement OIR	URGRA	
Capital Related					
Depreciation					
Taxes					
Return					
Gen.Plant					
Total	$154.132	$154.132	(a) XXX		
Contracts					
QFs - 1781 GWH	$129.475	$129.475	XXX		
Interutility - 650 GWH	$46.457	$46.457	XXX		
Bilateral - 1056 GWH	$62.910	$62.910	XXX		
Total w/o Int. Term. Contracts	**$238.842**	**$238.842**			
ISO-Related Charges					
Ancillary Services	-				
Other ISO Charges	$17.200	$17.200	XXX		
Grid Management Charge	$19.923	$19.923	XXX		
Total URG w/o Int. Term. Contracts	**$430.097**	**$430.097**			
Residual Residual Net Short			xxx		
(a)	SONG ICIP expense is part of this amount including fuel related expense.				

APPENDIX D
Page 3

		SOUTHERN CALIFORNIA EDISON COMPANY				
				Where to be Reviewed		
SCE		**D.02-04-016**	**AL 1616-E**	**and Adjusted**		
		Adopted ($ Millions)	**Res. Update Approved ($ Millions)**	**Procurement OIR**	**GRC**	
Revenue Requirements						
	Generation - 32,233 GWH					
1	Operating Expenses	$990,238	$990,238	(a)XXX	**XXX**	
	'Fuel Component w/o SONGs	$176,069	$176,069	XXX		
2	Capital Related		$236,331			
3	Depreciation	$102,506			**XXX**	
4	Taxes	$55,827			**XXX**	
5	Return	$106,137			**XXX**	
6	Gen.Plant	$42,271			**XXX**	
7	Total	$1,296,979	$1,226,569			
8	**w/ FF&U**	$1,311,527	$ 1,240,484			
	Purchased Power **					
9	QFs - 25,467 GWH	$2,130,162	$2,130,162	XXX		
10	Bilaterals - 1,533 GWH	$106,364	$106,364	XXX		
11	Interutility - 1,307 GWH	$161,255	$161,255	XXX		
12	Total	$2,397,781	$2,397,781			
13	**w/ FF&U**	$2,424,677	$2,424,677			
	ISO-Related Charges					
14	Ancillary Services	-				
15	Uplift Charges	$67,214	$67,214	XXX		
15.1	Add D.02-03-058 Costs	$15,484	$15,484	XXX		
16	**w/ FF&U**	$83,626	$83,626			
17	Total URG	$3,777,458	$3,707,048			
18	**Total URG w/ FF&U**	**$3,819,830**	**$3,749,102**			
	Residual Residual Net Short			xxx		
(a)	SONG ICIP expense is part of this amount including fuel related expense.					
**	DRI forecast of July 20, for July 2001 - June 2002; Energy, Capacity, Buyouts & Adm.					

END OF APPENDIX D

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