Decision **REVISED ALTERNATE PROPOSED DECISION OF COMMISSIONERS NEEPER & BILAS (Mailed 5/19/2000)~~ALTERNATE PROPOSED DECISION OF COMMISSIONERS NEEPER & BILAS (Mailed 4/20/2000)~~**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority to Establish Post-Transition Period Electric Ratemaking Mechanisms. (U 39-E)	Application 99-01-016 (Filed January 15, 1999)
Application of San Diego Gas & Electric Company for Authority to Implement Post Rate Freeze Ratemaking Mechanics (U 902-E) to Review and Recovery Transition Cost Balancing Account Entries from January 1, 1998 through June 30, 1998 and Various Generation-Related Memorandum Account Entries.	Application 99-01-019 (Filed January 15, 1999)
Application of Southern California Edison Company (U 338-E) to: (1) Propose a method to Determine and Implement the end of the Rate Freeze; and (2) Propose Ratemaking Mechanisms which would be in place after the end of the Rate Freeze Period.	Application 99-01-034 (Filed January 15, 1999)
Application of SAN DIEGO GAS & ELECTRIC COMPANY: (1) informing the Commission of the Probable Timing of the End of its Electric Rate Freeze, (2) for Authorization to Change Electric Rates Through Implementation of Interim Ratemaking Mechanisms Concurrent with Termination of the Electric Rate Freeze, and (3) for Authorization to Change Electric Rates by Adding New, and Revising or Terminating Existing, Rate and Revenue Mechanisms and Rate Designs. (U 902-E)	Application 99-02-029 (Filed February 19, 1999)

(See Decision 99-10-057 for Appearances.)

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FINAL OPINION REGARDING POLICIES RELATED TO POST-TRANSITION RATEMAKING

I. Summary

In this decision, we provide guidance on policies regarding the end of the rate freeze and associated post-transition ratemaking for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). We take steps designed to ensure a more level playing field in order to promote competition and provide consumers with more options.

As defined in the Scoping Memo for these proceedings, Phase 2 issues include broad rate design policy issues integral to the development of post-transition ratemaking. In this decision, we address the following issues:

1. whether and how to implement a procurement performance-based ratemaking (PBR) mechanism, and whether to accept SDG&E's proposed settlement;
2. if a procurement PBR is not adopted, what regulatory oversight is necessary and how should utility purchases for bundled service customers be determined to be reasonable;
3. when does the mandatory buy-sell requirement end; how does the buy-sell requirement fit into the various procurement options; and what is this Commission's jurisdiction vis-à-vis the jurisdiction of the Federal Energy Regulatory Commission (FERC);
4. how should price volatility be handled, i.e., should bundled service customers and others be subject to the price volatility inherent in the marketplace or should price caps or some type of balanced payment plan be instituted;
5. how should ongoing transition costs be allocated after the rate freeze ends;

6. how should restructuring implementation costs (also known as costs given § 376 treatment) be allocated;
7. how should nuclear decommissioning costs and public purpose program costs be allocated after the rate freeze ends;
8. how should the Rate Group Transition Cost Memorandum Accounts (RGTCOMA) be treated;
9. how should Regulatory Must Run (RMR) costs be allocated;
10. what is the appropriate recovery of costs booked into the Procured Electric Commodity Account (PECA), established in Decision (D.) 99-10-057;
11. how should load retention discounts for SDG&E be handled;
12. how should excess rate reduction bond proceeds be treated; and
13. how do these proceedings interact with the 1999 Revenue Adjustment Proceeding (RAP), the distributed generation rulemaking, and other proceedings.

We consider and reject the settlement regarding a procurement PBR mechanism presented to us by SDG&E, the Office of Ratepayer Advocates (ORA), the Utility Consumers Action Network (UCAN), the California Power Exchange (CalPX) and several other parties. We also reject PG&E's proposal to either adopt a procurement PBR or to establish guidelines for procurement. We do not continue the requirement that all three utilities continue to procure their energy only from the CalPX (also known as the mandatory buy requirement) until PG&E, Edison, and SDG&E have all ended the rate freeze. Instead, during the transition period, the UDCs may now purchase energy through the Cal PX or a mixture of the Cal PX and any qualified exchange, as authorized by future advice letter filings. We also ~~declare~~ re-affirm our decision in D.95-12-063 that, at the end of the transition period, the mandatory buy requirement is eliminated for bundled customers.

We do not adopt PG&E's rate capping proposal. We prefer that customers understand the impact of the market and the accompanying price signals. We call for the utilities and energy service providers (ESPs) to provide the necessary customer education and information and recommend that hourly interval meters be installed whenever feasible. We also continue the balanced payment plan for residential and small commercial customers. We do not require that such plans be expanded to street lighting customers, rather, we see this as an opportunity for the marketplace to offer solutions.

We make several findings related to cost allocation after the rate freeze ends for each utility. For ongoing transition costs, utilities are directed to file an ~~application~~ Advice Letter within 60 days ~~showing the cost responsibility for each class and comparing the day-ahead hourly PX prices for all hours of 1999 with load patterns and usage levels per class~~ updating the top 100 hours methodology. Restructuring implementation costs and nuclear decommissioning costs should be allocated according to a cents-per-kilowatt methodology. Public purpose program costs related to energy efficiency should continue to be allocated according to a system average percent change (SAPC) methodology.

We also address issues related to SDG&E's rate reduction bonds. The unrealized savings resulting from the excess rate reduction bond proceeds must be refunded to ratepayers at SDG&E's authorized pre-tax rate of return by a ~~one time~~ refund and/or credit ~~or check~~. Finally, we address other issues related to our post-rate freeze policies in the body of this decision.

II. Background and Procedural History

As required by D.97-10-057, PG&E, Edison, and SDG&E filed applications in order to establish the ratemaking mechanisms for the period following the rate freeze and to establish procurement and ratemaking policies for the post-transition period. As we discussed in D.99-10-057, Pub. Util. Code § 368(a)[1] established that electric rates would remain fixed at the June 10, 1996 levels, except that rates for residential and small commercial customers were reduced by 10% from those levels. This "rate freeze" was put into place in order to allow PG&E, Edison, and SDG&E to recover uneconomic investments in generation facilities. Section 367 defined these uneconomic costs, or transition costs, and established that such costs must be recovered by December 31, 2001, with certain exceptions, as delineated in §§ 367, 375, 376, and 381. Pursuant to § 368(a), the rate freeze continues until the generation-related transition costs are recovered, but no later than March 31, 2002.

A prehearing conference (PHC) was held on February 18, 1999. The scoping memo, issued on March 11, 1999, divided consideration of these applications into two phases and established that the assigned administrative law judges (ALJ) are the principal hearing officers.[2] Phase 1 addressed the mechanics of ending the rate freeze and these issues were considered in D.99-10-057. SDG&E filed an additional application, Application (A.) 99-02-029, in which it notified the Commission of its intent to end the rate freeze on approximately July 1, 1999. A second PHC was held on March 12 to discuss the impact of A.99-02-029, which was consolidated with these proceedings. A second Scoping Memo was issued on March 15. The Commission reviewed the proposed ratemaking and accounting mechanisms on an expedited basis. These

[1] All statutory references are to the Pub. Util. Code, unless otherwise noted.

[2] ALJ Kim Malcolm was the principal hearing officer for Phase 1; ALJ Angela Minkin is the principal hearing officer for Phase 2.

issues were addressed in a settlement by the active parties that resolved outstanding issues for SDG&E on an interim basis. The Commission adopted the settlement, with conditions, in D.99-05-051, which was further refined with respect to Phase 1 issues in D.99-10-057.

Ten days of evidentiary hearings were held and Commissioner Duque attended closing arguments on September 27. The proceedings were submitted upon receipt of reply briefs, on November 5, 1999.[3] On October 27, SDG&E, ORA, UCAN, CalPX and other parties filed a proposed partial settlement agreement and on October 29, these parties filed a motion to set aside submission of the proceeding. On November 2, the assigned ALJ issued a ruling establishing dates for commenting on the proposed settlement and for responses to the petition to set aside submission. These proceedings were properly reopened for purposes of considering the settlement and comments on the settlement. The proceedings are deemed submitted as of December 13, the date of reply comments on the settlement.

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[3] PG&E, Edison, SDG&E, ORA, California Energy Commission (CEC), UCAN, The Utility Reform Network (TURN), James Weil (Weil), Federal Executive Agencies (FEA), Alliance for Retail Markets (ARM), Western Power Trading Forum, CalPX, Automated Power Exchange (APX), Coalition of California Utility Employees (CUE), California Farm Bureau Federation (Farm Bureau), California City-County Street Light Association (CAL-SLA), jointly California Department of General Services, University of California, and California State Universities (collectively, State Consumers), New West Energy Corporation, Commonwealth Energy Corporation, and, jointly, California Manufacturers Association, California Large Energy Consumers Association, and California Industrial Users (collectively, Large Users) filed concurrent opening briefs. With the exception of Weil and Commonwealth, the same parties filed concurrent reply briefs. On November 5, Large Users requested leave to file their joint reply brief one day late. This motion is granted.

III. Procurement Issues

Much of the debate in these proceedings has focused on the energy procurement practices of the utility distribution companies (UDCs) for their bundled (or full service) customers after the rate freeze ends or the transition period is over.[4] The UDCs must supply kilowatt-hours (kWh) to their full service customers and must also obtain ancillary services and replacement reserves for the load associated with these customers.[5]

Until the utilities collect their uneconomic transition costs and the rate freeze ends, as it has for SDG&E, rates are fixed at the June 10, 1996 levels. As explained above, these frozen rates, along with a residual component of rates specifically delineated as the Competition Transition Charge (CTC), allow the utilities to accrue the revenues to collect transition costs.

We must determine whether to establish an incentive mechanism to apply to the procurement of the wholesale commodity, to continue to require the UDCs to purchase the commodity through the CalPX, to prescribe specific purchasing guidelines, or to establish reasonableness reviews. The goal of each of these approaches is to ensure that service for bundled customers is provided at

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[4] This proceeding is not the forum to consider who should provide power to default customers, defined as those customers who do not affirmatively elect an energy service provider. As it stands now, customers remain bundled customers of the UDCs unless they affirmatively make such an election. In D.99-10-065, we ordered a staff study on various issues, including the issue of default providers and issues related to those customers the market is willing to serve and those customers who must turn to a provider of last resort for service. This decision uses the term "bundled customer" or "full service customer" in considering those customers who do not affirmatively elect an energy service provider.

[5] Ancillary services consist of grid reliability services, including, but not limited to, spinning reserves, non-spinning reserves, replacement reserves, voltage support, and black-start capability.

reasonable rates. PG&E and SDG&E propose that an electric procurement PBR mechanism be instituted. Several other parties believe that such an incentive mechanism is premature and that the utilities should be required to continue to purchase power from the CalPX or that other specific purchasing guidelines be established.

On October 29, SDG&E, ORA, UCAN, CalPX, Duke Energy Trading and Marketing, LLC, Hafslund Energy Trading, LLC (Hafslund), and California Polar Power brokers, LLC (CALPOL)[6] (collectively, settling parties) requested that the Commission adopt a settlement agreement that would resolve or otherwise dispose of all issues raised in connection with SDG&E's electric procurement PBR. We will review this settlement under the settlement rules provided in Rule 51 *et seq.*[7] These rules provide that any settlement must be found reasonable in light of the whole record, consistent with the law, and in the public interest.

A. Procurement Proposals

1. PG&E

PG&E presents two alternatives for our consideration. PG&E proposes that the Commission should either adopt a prescribed procurement practice, which would require PG&E to procure electricity and ancillary services for bundled customers through a specific mix of purchases in defined markets, or

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[6] Hafslund and CALPOL filed separate motions to intervene in these proceedings for the purpose of entering into the proposed settlement agreement. Reliant Energy Power Generation, Inc., Williams Energy Marketing & Trading Company, and British Columbia Power Exchange Corporation also filed motions to intervene for the purpose of filing comments on the proposed settlement. Each of these motions is granted.

[7] References to rules are to our Rules of Practice and Procedure, California Code of Regulations, Title 20.

the Commission should adopt an Electric Procurement Incentive Mechanism (EPIM). Either of these alternatives is acceptable to PG&E and would avoid the need for reasonableness reviews.

PG&E states that it is not feasible to obtain 100% of its metered load in the PX day-ahead market. For example, from May 1998 through April 1999, PG&E purchased approximately 10% of its monthly energy needs from the real-time market. Instead, PG&E maintains that a Commission-prescribed procurement practice is acceptable and must allow for sufficient flexibility so that PG&E can adjust to variations in market conditions. The defined markets for purchases would include the PX day-ahead, day-of, and block forward market, the Independent System Operator (ISO) imbalance energy market (also known as the real-time market), and could include the APX. PG&E states that the advantages to this approach include providing a transparent benchmark for ESPs, allowing the pre-established markets more time to become more efficient and robust, minimizing the incentive to take undue risks in the procurement market, and reducing regulatory oversight and review. PG&E categorically rejects the use of traditional reasonableness reviews in assessing procurement practices.

ORA contends that the procurement from the day-ahead market and any resulting charges set by the ISO markets for imbalance energy, ancillary services, unaccounted-for energy, and other costs is an example of a conservative approach that would not require detailed review. ORA would consider costs over a period of time that were above the day-ahead PX price to be a possible indication that a utility has engaged in imprudent or risky procurement practices. Alternatively, ORA would accept PG&E's proposal of procurement guidelines and states that PG&E's identification of the day-ahead PX price plus 2% as being equivalent to and simpler than ORA's offer to deem the PX price for forecasted load plus pass-through of ISO settlement costs as a benchmark for reasonableness. ORA believes that there are too many problems in the evolving marketplace to accept PG&E's alternative proposal for a procurement incentive mechanism.

PG&E proposes that the EPIM would be based on an annual market benchmark, an asymmetric deadband, and 50 / 50 sharing of savings or costs outside of the deadband between ratepayers and shareholders.

The annual benchmark would consist essentially of all possible costs that PG&E would incur were it to continue to procure the commodity through the PX. As proposed by PG&E, the costs included in the benchmark consist of 1) settlement quality metered load data of bundled customers multiplied by final PX day-ahead zonal market clearing prices, 2) all ISO costs allocated to the PX or to other scheduling coordinators used by PG&E, 3) PX and ISO administrative and other charges allocated to PG&E, and avoided PX and ISO charges that would have been allocated to PG&E had PG&E continued to use the PX exclusively as its scheduling coordinator. The actual costs incurred by PG&E on an annual basis for energy purchases through various markets plus the costs of ancillary services, real-time costs, and other charges by the ISO to the PX and to other scheduling coordinators used by PG&E would then be compared to the benchmark. While PG&E supports using the day-ahead PX market in its benchmark, it would not object to the use of a simple benchmark based on a volume-weighted average of defined markets.

PG&E contends that an asymmetric deadband of three percent above the benchmark is required to account for forecasting errors. As an alternative, PG&E states that the forecasting error can be addressed by adding two percent to the day-ahead market benchmark. PG&E maintains that either of these adjustments are necessary to ensure that, over time, there will be zero gains and losses through the operation of the EPIM. Without such an adjustment, PG&E states that it would lose approximately $10 - $15 million per year, with a risk of losses exceeding $50 million per year. PG&E has proposed various complicated accounting mechanisms to track the shared savings or losses.

PG&E maintains that the EPIM has several benefits, including aligning shareholder and ratepayer interests and encouraging PG&E to continue buying from markets included in the benchmark, which allows these markets to become more efficient and robust. In addition, PG&E states that it provides PG&E with the opportunity to compete for wholesale supplies to lower bundled service costs if bilateral purchases are allowed as part of the PBR and reduces regulatory oversight costs.

2. SDG&E

SDG&E proposes a two-part PBR mechanism. Part A addresses SDG&E's procurement of electricity. Part B addresses SDG&E's administration of existing long-term contracts. SDG&E contends that an electric commodity incentive mechanism is consistent with the intent expressed in the Preferred Policy Decision (D.95-12-063, as modified by D.96-01-009):

> Utilities will continue to procure power for those customers who choose not to arrange retail contracts with suppliers and will continue to provide nondiscriminatory distribution services to all customers within their service territories. These procurement and distribution functions of the utilities will remain under our regulation and be subject to incentive regulation. (*Id.*, p. 26.)

Like PG&E, SDG&E maintains that an incentive mechanism is appropriate in order to align the interests of both shareholders and customers, to provide for more efficient utility operations, and to decrease regulatory burdens. SDG&E proposes a volume-weighted multi-part benchmark and equal sharing of gains and losses between customers and shareholders, *i.e.*, 50% to customers, 50% to shareholders.

As proposed, Part A of the Electric PBR would establish a monthly benchmark for electric procurement for bundled customers. SDG&E, at its sole discretion, would purchase energy from any of the PX energy markets, from the ISO's imbalance energy market, or from other parties. SDG&E's purchases to serve metered load would then be compared to the monthly benchmark. If SDG&E's costs were lower than the benchmark, savings would be shared between customers and shareholders. Similarly, if costs were greater than the benchmark, the additional costs would be shared between customers and shareholders. In response to concerns expressed by several parties, SDG&E has modified its proposed energy benchmark to consist of a volume-weighted average of the PX day-ahead market, the PX hour-ahead market, and the imbalance energy market.

SDG&E will continue to obtain ancillary services and replacement reserves for the load associated with its bundled customers. Under the electric PBR proposal, SDG&E would charge customers the final day-ahead and hour-ahead market clearing price for those services, as determined by the ISO, times the respective quantities of the day-ahead and hour-ahead service that the ISO allocates to SDG&E to meet reliability criteria. This ISO-determined charge becomes part of the Part A benchmark. SDG&E contends that since the ISO's market price for ancillary services are objectively determined and because the quantity is determined by the ISO, these charges must be *per se* reasonable. The costs for ancillary services, on average, are approximately 12% of total energy costs. Under the proposed PBR mechanism, if SDG&E obtains ancillary services at a lower cost than the costs SDG&E would have otherwise paid to the ISO, the savings would be shared with customers. Similarly, if SDG&E were to obtain these services at a higher cost than it would otherwise pay to the ISO, the costs would also be shared with customers.

SDG&E contends that this PBR mechanism delivers several benefits. It provides incentives for SDG&E to serve bundled customers at the lowest possible price and avoids reasonableness reviews. The mechanism is transparent because it is designed around a benchmark that is public and determined by market bidding for load and supply, and it is simple because it is based on reported meter data and public market prices. SDG&E expects that most purchases would be made through the PX, as long as the PX is "efficient and competitive" (SDG&E Opening Brief, p. 9), but would consider any market transaction designed to reduce its costs. Examples of these transactions include purchases or sales in the PX day-ahead or day-of market; energy or ancillary services purchases or sales in the ISO's markets; bilateral purchase or sales from third parties; purchases of incremental transmission to access economic power; and the purchase of Firm Transmission Rights to mitigate the cost of transmission congestion.

SDG&E's Part B of its proposed electric PBR is designed to obtain savings under its existing long-term purchased power contracts by negotiating contract modifications to lower total costs. SDG&E explains that its performance would be measured by comparing the above-market costs to purchase energy and capacity under the contracts as they currently exist with the actual above-market costs incurred under the renegotiated contracts. Savings or costs would be shared between customers and shareholders on a 50/50 basis and would be applied to ongoing transition costs.

SDG&E administers approximately 80 contracts with qualifying facilities (QF), under which it pays the QF for capacity and energy at authorized prices as specified in each contract. SDG&E also purchases energy and capacity from Portland General Electric (PGE) and Public Service of New Mexico (PNM) under long-term arrangements approved by the Commission. SDG&E contends that this incentive mechanism would not apply to the contract restructurings or buyouts contemplated in the Preferred Policy Decision or § 367. SDG&E maintains that this incentive mechanism is required to allow it to capitalize upon short-term opportunities for pricing modifications without relying on the need for Commission approval.

B. Summary of Parties' Positions

Edison recommends that any decision the Commission adopts regarding procurement incentive mechanisms be limited to the parties proposing such a mechanism. Edison intends to provide specific proposals on energy procurement for bundled customers in its rate design filing.[8] Edison contends that it is essential that UDC flexibility in procurement practices be maintained, but insists that retrospective reasonableness reviews must be avoided.

While parties recognize that there is concern about protecting full service customers with respect to the reasonableness of commodity procurement, a wide range of parties oppose establishing a procurement PBR. For example, TURN, CEC, FEA, State Consumers, Large Users, ARM, WPTF, Farm Bureau, Commonwealth, and New Energy oppose a procurement PBR. Generally, these parties believe that it is premature to establish such a mechanism, since the role of the UDC and default provider issues have yet to be determined. In particular, ARM, FEA, and Farm Bureau point out that allowing the UDC to become more invested in procurement for bundled customers will make it more difficult to define the role of the UDC and could restrict the Commission's options in the

[8] Edison filed A.00-01-009 on January 10, 2000.

staff study ordered by D.99-10-065. ARM believes that the Commission must determine whether a utility should be a competitor to the ESPs or merely a default supplier before a procurement PBR can or should be implemented. State Consumers and Large Users maintain that the UDC's role is that of a distribution company and that commodity procurement for bundled customers should simply be a pass-through of commodity costs. While ORA believes it is premature to devise utility-specific procurement PBR mechanisms, ORA also maintains the Commission should adopt the settlement regarding SDG&E's proposed mechanism, as described below, with certain restrictions and limitations, in order to allow the Commission to gather empirical data about the efficacy of such a mechanism.

Parties representing both competitors and large users state that a procurement PBR mechanism is antithetical to a competitive market. ORA is also concerned that incentive mechanisms may conflict with the development and maturation of competition in procurement. FEA, ARM, and WPTF acknowledge that functions that remain under monopolies have been subject to a PBR mechanism and that substituting incentives for competition is a stated goal for PBRs. These parties contend, however, that it is not appropriate to substitute regulatory mechanisms for competition in the areas of the marketplace where the Commission hopes to foster competition.

Several parties believe that retail competition will not become vibrant or robust if the UDCs are permitted additional procurement activities. Allowing the UDCs to profit from procurement would provide an incentive to retain customers and place the UDCs in direct competition with the ESPs. Parties representing large users and competitors point out that this result would be harmful to the development of direct access and to meaningful competition. In general, parties contend that the UDCs still have market power and this would frustrate competition.

While TURN, ARM, and CMA recognize that PBR mechanisms have been successfully applied to gas procurement, this did not occur until the restructured gas market had been in place for several years. The UDC did not dominate the gas market to the extent it does the electric market and the maturity of the gas market when incentives were put in place far exceeded the current state of the nascent electric market. Furthermore, ARM and WPTF contend that the PBR would provide an incentive to "game" the market in that the UDC would attempt to maximize returns by purchasing large volumes and buying power in excess of bundled customers' needs. The UDC would then attempt to sell the excess power for a profit, but if it cannot do so, the ratepayers would simply assume 50% of the costs.

Several parties are concerned about the design of the proposed PBR mechanisms. TURN, Weil, CEC, FEA, State Consumers, and Large Users contend that a PBR mechanism can only be effective if the benchmark is exogenous from the actions of the entity against which performance is being evaluated. Unless the UDC has no ability to influence the benchmark, there is no incentive for the UDC to obtain lower prices for power. TURN, for example, does not accept that a UDC, even one of SDG&E's size, cannot influence the market. While SDG&E contends that it does not exercise market power and that its total participation in the market is a small fraction of the total market transactions, TURN argues that actual PX supply and demand data demonstrate that a shift of only 250 megawatts (MW) of load could impact the PX clearing price by over 30%. TURN points out that SDG&E may serve as much as 3,200 MW of default customer demand and could shift approximately 500 MW of that demand between the day-ahead and real-time markets.

ORA supports a settlement approach for SDG&E's procurement PBR, but recommends that PG&E and Edison be subject to defined reasonable, conservative procurement practices that would not be subject to detailed later review. ORA recommends that the utilities schedule their day-ahead forecast of bundled service customers' load in the PX day-ahead market and accept any resulting charges by the ISO for imbalance energy, ancillary services, unaccounted for energy, and other costs. Over time, costs greater than the day-ahead market could be viewed as an indication that the utility has procured power imprudently and these costs could be determined to be unreasonable. The State Consumers agree that conservative, simplified pre-approved commodity procurement practices are appropriate and that the utilities should avoid incurring any additional risks beyond these conservative purchasing practices. On the whole, State Consumers agree with PG&E's alternative approach and support the development of commodity procurement guidelines.

Nearly all parties agree that reasonableness reviews are not appropriate. ARM and WPTF disagree with the concept of pre-approved procurement practices unless the Commission has first analyzed and determined the role of utilities in the post-rate freeze market. If the UDCs simply supply their bundled customers with power and do not compete with ESPs, ARM agrees that pre-approved procurement practices are appropriate. However, if utilities are allowed to compete with ESPs for customers then ARM contends that the UDCs must be exposed to exactly the same risks as their competitors.

ARM also maintains that commodity PBR mechanisms will create a perverse incentive to limit load curtailments. UDC-managed load curtailment is instituted to maintain reliability and ARM believes that an expected outcome of these programs will be to reduce prevailing prices in the PX. However, when commodity PBR benchmarks are based, even in part, on PX prices, the implementation of load curtailment would then reduce the benchmark price. A lower benchmark means that it is less likely that the UDC will earn a profit. To the extent that an UDC has discretion in implementing such load curtailments, utility behavior may be influenced by this impact.

C. SDG&E Proposed Settlement

After submission of testimony by all parties, SDG&E began informal settlement discussions regarding a procurement PBR mechanism. A settlement conference was held on September 27, 1999. The parties to the settlement are SDG&E, ORA, UCAN, CalPX, Duke, Hafslund, and CalPol. The settling parties propose this experimental procurement PBR because of SDG&E's relatively small market share and load characteristics and to provide information for future procurement proposals. In addition, unlike the other UDCs, SDG&E has already ended its rate freeze.

The proposed settlement recommends that SDG&E be authorized to purchase up to 20% of the annual electric commodity requirements of its full service customers through bilateral contracts, derivatives, or other transactions outside of the CalPX and ISO imbalance energy markets. At least 80% of its full service requirements would be purchased through the CalPX and ISO through 2004. The settling parties propose a 36-month term for the experimental procurement PBR.

The proposed mechanism measures SDG&E's performance in two markets: the energy market and the ancillary service capacity market. In each market, a benchmark price is established which is then multiplied by an energy consumption or demand measure to arrive at projected cost for that benchmark. The cost estimate is then compared to SDG&E's actual cost in each market for purposes of sharing gains and losses. Gains and losses are subject to progressive sharing of gains and losses, except within the first range, a deadband where all losses are assigned to ratepayers. The proposed procurement PBR includes a midterm review, as well as an evaluation, monitoring, and reporting plan.

PG&E, Edison, CEC, TURN, State Consumers, CIU, FEA, Farm Bureau, ARM, WPTF, CUE, APX, Williams Energy Marketing and Trading Company (Williams), Reliant Energy Power Generation, Inc. (Reliant), and Dynegy, Inc. filed comments on the proposed settlement. The settling parties, CEC, State Consumers, ARM, and APX filed reply comments.[9]

CUE, Williams and Reliant support the proposed settlement. Edison wants to be sure that the settlement, if adopted, is not construed as precedential for Edison. PG&E opposes the settlement insofar as it can be construed as preventing PG&E from having its own procurement incentive mechanism during the three-year experiment; if this is not the case, PG&E supports the adoption of a procurement PBR for SDG&E.

All other parties oppose the settlement on policy grounds. Similar to their comments on SDG&E's original proposed PBR mechanism, these parties believe that as long as the UDCs are in the position of providing procurement service to bundled service customers, the customers should not be put at risk for potential losses generated from market participation outside this Commission's approved commodity exchanges. In addition, these parties generally believe that even adopting the proposed settlement as an experiment or pilot program would not be productive. Such an experiment would not yield information relevant to

[9] On November 30, Farm Bureau moved for acceptance of late-filed comments on the proposed settlement. On December 14, 1999, SDG&E, ORA, UCAN, and CalPX moved for acceptance of their late-filed joint reply comments to the proposed settlement. On December 15, APX made a similar motion. Each of these motions is granted.

other utilities, since, according to these parties, SDG&E's geographic situation is unique with regard to transmission constraints and access to imported energy. Therefore, it is not clear how an analysis of SDG&E's actions under a procurement PBR mechanism can be extrapolated to apply to or provide information on the actions of PG&E and Edison.

State Consumers recommend that if Sempra, SDG&E's parent company wishes to undertake such activities, it should do so through an unregulated affiliate. State Consumers also point out that in D.99-07-018, we considered a similar request in Edison's application for a pilot program for reselling bilateral forward purchases to the CalPX and the ISO. Similar to the pilot program that was rejected in that decision, State Consumers believe that the SDG&E pilot contemplates the UDC engaging in procurement practices that expose ratepayers to financial risks beyond those that would be experienced through current practices.

FEA opposes the proposed settlement and reminds us that one purpose of electric restructuring is to move away from an administrative or regulatory structure to one driven by competitive market forces. Thus, FEA maintains, that the way to do this is to ensure that competitive forces work by taking steps to strengthen the direct access market, such as removing market barriers customers face in signing up with direct access suppliers and ensuring market power abuses are monitored and reported. FEA also contends that there are several problems with the benchmarks for both the energy prices and ancillary service capacity. While FEA agrees that the three-part weighted average benchmark for energy prices is better than the single benchmark originally proposed by SDG&E, FEA argues that the proposed benchmark does not include all relevant energy products or state what the optimal weighting of purchases would be.

TURN, ARM, WPTF, and the CEC argue that it is inappropriate to implement a procurement PBR before the Commission has determined the role of the UDCs in the post-transition market. ARM states that such a PBR could provide SDG&E with an incentive to compete with ESPs, to retain customers, to compromise price transparence, and to manipulate the PX market. ARM argues that shareholder profits are directly tied to the volume of the utility's throughput, which in turn causes the utility to be motivated to actively engage in customer retention efforts. ARM also argues that a procurement PBR does not provide protection for small customers. Because it would stifle competition, the consumer would ultimately be the loser, due to inhibited innovation, and squelched price competition, as well as the need for increased regulatory oversight. Without price transparency, competition cannot flourish, contends ARM, and a utility with a procurement PBR mechanism has every incentive to compromise price transparency, because this could result in greater customer retention, which would lead to increased procurement requirements and the potential for greater PBR profits for its shareholders.

Farm Bureau and the CEC contend that the proposed settlement is premature. CEC also maintains that including ancillary services in the PBR mechanism make it much more complex. Like FEA, the CEC is concerned that the settlement includes an imprecise definition of the ancillary services benchmark. CEC points out that the ancillary services market is much more complex than energy markets and point out that SDG&E could have the opportunity to attempt to manipulate rules for ISO market participants and the ISO Rational Buyer program. The CEC also argues that the prospects for sustained gains by SDG&E for procurement outside of the CalPX is low and that the design of the PBR is stacked against the interests of ratepayers. WPTF agrees that ratepayer benefits will be minimal and that the mechanism will reward

SDG&E for engaging in customer retention efforts and using its market power to compete with ESPs.

TURN is also concerned about potential problems with affiliate transactions, particularly because the PBR mechanism would not provide for reasonableness reviews. TURN describes the following scenario: if SDG&E purchased energy from an affiliate at a higher price than the PX, the sharing mechanism would require some portion of that excess payment to be borne by SDG&E's shareholders. However, because the amount borne by shareholders is less than 100%, Sempra as a whole could profit from affiliate sales to SDG&E in spite of the incentives provided to the UDC by the PBR mechanism. TURN argues that these transactions could be complex and difficult to monitor and that even a conventional reasonableness review may not provide adequate consumer protection. TURN is also concerned that there is no quantitative analysis of how the PBR will work in practice.

APX also opposes the proposed settlement, albeit from a very different perspective. APX argues that the Commission should reject the settlement unless we also remove the restrictions imposed on SDG&E's right to trade outside of the CalPX. APX contends that the buy-sell mandate must end with the end of the transition period, which it argues, ends for a particular utility when that utility ends its rate freeze. APX maintains that by continuing the bulk of its trades with CalPX through 2004, the settlement violates the Preferred Policy Decision. APX also believes that the settlement contradicts the Preferred Policy Decision because these restrictions do not acknowledge the role of direct access. Like FEA, APX contends that effective competition from direct access will control the UDC's procurement practices and eliminate the need for trading restrictions.

Dynegy agrees that the settlement should be rejected because it extends the mandatory buy-sell obligation past the period contemplated in electric restructuring legislation. Because SDG&E has collected its transition costs, Dynegy believes SDG&E should immediately be allowed to enter into bilateral contracts. Dynegy also recommends that other indices should be included in benchmarking analyses, although it is amenable to using the PX price for a limited period. Dynegy recommends that the CalPX should be one of many available markets and that the structure of the PX is not truly reflective of open markets. Dynegy argues that mandatory purchasing through the PX also carries with it the requirement to pay the CalPX administrative fee of $.31 per MWh, a fee that would be added to a customer's bill, but that could be negotiated through the bilateral contracting process.

Williams and Reliant believe that retail customers will benefit from SDG&E's ability to make limited purchases outside the CalPX market and that SDG&E's circumstances justify this experiment. Williams also argues that a PBR benchmark is inappropriate and should not be established. While Reliant recognizes that the Commission has yet to rule on the role of the UDC, Reliant does not believe approval of the settlement prejudges the issue. Like APX, Reliant and Williams recommend that the Commission allow for the possibility of gradually increasing the 20% limitation, should we determine that such an increase would assist in the development of a robust market. Reliant also recommends that the Commission retain the ability to modify or terminate the settlement's requirement that the buy mandate extend through 2004. Williams recommends that the buy requirement be eliminated or, at a minimum, not extended beyond March 31, 2002.

D. Mandatory Buy-Sell Requirement and the Transition Period

PG&E, Edison, SDG&E, Weil, and APX contend that the transition period ends simultaneously with the end of each utility's rate freeze period.

ARM, WPTF, FEA, State Consumers, Large Users, TURN, and CalPX maintain that these periods are not synonymous. These parties contend the transition period was created not solely for the purposes of stranded generation cost recovery, but also to ensure the evolution of transparent markets with enough depth to allow for meaningful competition. In other words, these parties argue that the CalPX and the ISO must mature sufficiently in order to give the nascent retail direct access market an opportunity to develop robust competition. While these parties recognize that Assembly Bill (AB) 1890 reduced the period contemplated in the Preferred Policy Decision for recovery of stranded costs from five years to four years, they do not agree that the transition period applies only to stranded asset recovery.

The State Consumers, in particular, point to the fact that the ISO and the CalPX are changing institutions, evolving in efforts to enhance price signals, improve efficiencies, and to bring new products to the wholesale market. ARM argues that the buy-sell requirement should only cease after the Commission has promulgated its principles for analyzing competition in retail markets, established measures for the mitigation of market power, and comprehensively unbundled the costs associated with retail electric service from distribution rates.

CalPX strongly advocates that the mandatory buy-sell requirement continue for a defined period of time to ensure that the CalPX has adequate depth and liquidity to foster development of a competitive market. CalPX states that these are critical attributes of a robust, competitive market with reliable price signals. Thus, it is simply premature to end this requirement, regardless of whether one or more utilities have achieved an end to the rate freeze.

Despite the fact that the utilities have divested a substantial amount of their generation assets, State Consumers, TURN, ARM, and WPTF contend that PG&E, Edison, and SDG&E will continue to operate as the largest purchasers in procuring the retail commodity in the wholesale market and, as such, will continue to maintain their monopsony power. Thus, these parties recommend that a mandatory buy element is required, while recognizing that FERC has somewhat relaxed its requirement regarding the mandatory sell element for SDG&E.[10]

State Consumers, CalPX, ARM, and other parties are convinced that this authority does not reach any requirement this Commission may impose as to the retail services the utility provides to its full service customers. These parties also submit that FERC's concern focuses on potential market power in the wholesale generation sector, rather than any market power held by the largest purchases in defined retail areas. Thus, these parties contend that it is within our jurisdiction to assert our consumer protection powers to define those commodity purchase practices applicable to utility commodity service for full service customers. ORA agrees that the mandatory buy-sell requirement should continue for at least the five-year term established in FERC's December 18, 1996 decision (77 FERC ¶ 61,265 at 62,088 (1996)), but contends that it is premature to determine whether the buy-sell requirement should continue beyond this time.

E. Rate Volatility, Rate Capping, and Balanced Payment Plan

Recognizing that there is a strong possibility for volatility in energy prices once the rate freeze has ended, PG&E proposes price caps and argues that

[10] SDG&E requested approval to enter wholesale markets, other than the CalPX, to sell certain generation, limited to that obtained from certain power purchase contracts. FERC's order granted this limited waiver of the sell requirement, but did not extend its reach to power from SDG&E's own generation or from that obtained from QF contracts. Order Granting Waivers and Conditionally Accepting for Filing Revised Market-Based Rate Tariff (September 10, 1999) in Docket ER99-3426-000 (September 1999 FERC Decision), mimeo. at pp. 4, 5-6.

expansion of its current bill smoothing program should not be expanded to non-residential customers. Edison and SDG&E make no proposals to mitigate price v~~v~~olatility. With the exception of CAL-SLA, all parties oppose price caps, claiming that such devices will dilute market prices and distort market signals. However, several parties support balanced payment plans (BPPs) to mitigate high prices. They contend that BPPs will allow for customer education about energy prices and increase usage pattern consciousness. Other parties argue that bill smoothing services, such as BPPs, should be confined to ESPs and should not be offered by UDCs. In many respects, the arguments surrounding rate capping are highly correlated to parties' positions on the proper role of the UDC in procurement. To the extent that parties recommend a limited UDC role in procurement or only a "plain vanilla" offering, they generally oppose the UDC's ability to cap rates.

The parties differentiate between rate capping and rate leveling (e.g., BPPs). Under a rate-capping plan, as proposed by PG&E, commodity prices would be capped once prices reach a given level to insulate customers from high prices during times of high demand. The current month's charge is limited to the capped rate with recovery of the amount above the cap collected in the following month. The customer pays interest on the amount deferred to subsequent months and a balancing account is proposed for revenue tracking.

Specifically, PG&E proposes to implement a capping mechanism for default customers with loads under 500 kW to insulate them from high commodity prices. The cap will be triggered when commodity prices over the most recent 30 days are 150% higher than the average PX price over the previous 12-month period. As proposed by PG&E, the capping mechanism is mandatory for all default customers. PG&E proposes rate capping for one year. Ratemaking would occur through the Deferred Procurement Revenue Account (DPRA), which would be established to facilitate treatment of the capping revenues.

Under a balanced payment plan, a customer incurs its actual commodity cost obligation each month but the utility allows the payment to be spread over subsequent months with a true up at year end. Under the BPP, the customer is conscious of energy prices and can act to adjust usage patterns. The primary distinction between rate capping and a BPP is the information a customer receives about prices. The utilities already have BPPs in place for residential customers. PG&E states that 10% of residential customers opt for BPPs.

SDG&E instituted a temporary three-month rate cap at the end of its rate freeze as part of its interim settlement adopted in D.99-06-051. The rate cap has since expired. As part of its interim settlement, SDG&E agreed not to seek a similar rate cap for the summer of 2000; however, it believes that BPPs should continue to be an option for full service customers.

CAL-SLA not only supports rate capping, it also specifically recommends extending the BPP to streetlighting customers. CAL-SLA argues that city governments require balanced payments to mitigate price volatility due to budgetary issues and the fact that cities and local governments cannot adjust the usage patterns for streetlights to respond to fluctuating energy prices. CAL-SLA finds PG&E's argument that it cannot extend the BPP to streetlighting customers because of computer system problems to be unpersuasive given that it can offer it to residential customers and has continued to promote BPP to residential customers. In addition, CAL-SLA points out that both SDG&E and SCE have either offered or have proposed to offer this rate option to streetlighting customers.

While supporting the concept of rate capping, CAL-SLA does not support PG&E's proposed rate cap because it would not sufficiently dampen price volatility since it would not trigger until the 30-day average price exceeds the 12-month rolling average by 150%. CAL-SLA believes that the specifics of rate capping approaches should be litigated in each utility's rate design case but that this proceeding should establish a policy that rate caps should be implemented for small customers of each utility after its rate freeze ends. Farm Bureau also recommends that rate capping and levelized pay plans should be explored in each utility's rate design proceeding in order to better assess the costs and overall rate design impacts.

ORA states that it is open to considering rate capping options as each utility's rate freeze ends, but it would not establish a policy on rate capping in this proceeding. Instead, ORA recommends continued use of existing BPPs as a mechanism to limit volatility.

In direct testimony, the FEA acknowledges that price caps will dilute commodity prices and mute market signals. However, it believes that caps can be allowed as a voluntary competitive option.

State Consumers believe that UDCs should be confined to distribution services and that a vibrant market will not emerge if the UDC continue to undertake additional commodity activities. State Consumers argue that:

> "Development of new commodity rate structures, such as capped rates, would dilute the price signal reflected in the hourly value of energy discovered in the exchanges, and would require the UDC to carry costs in excess of the capped charge until later recovered from customers. However our opposition to capped commodity rates does not translate into an opposition for levelized payment plans where the customer incurs an obligation for the current-month commodity costs." (Opening Brief, p. 5.)

TURN supports retention and expansion of balanced payment options but opposes commodity price caps as proposed by PG&E. TURN points out that customers will still pay for higher rates under a rate cap but instead will have price signals dampened, further encouraging inefficient usage patterns. TURN suggests that rather than promoting rate caps, UDCs should instead spend their time developing programs that will allow consumers to see and respond to price signals.

UCAN argues that bill-smoothing activities, including BPPs, are outside of the UDC's core distribution services. UCAN argues that only if the market fails to provide this service should the Commission allow UDCs to provide it.[11] UCAN notes that even the CAL-SLA concedes that ESPs are providing bill smoothing products to customers, negating the need for UDC to increase non-distribution services.

Weil opposes mandatory rate caps without further study by PG&E. On cross-examination, Weil established that PG&E conducted no study or analysis of customer preferences for capped commodity costs. Weil does not oppose optional programs designed by utilities to meet identified customer needs for stable prices. In addition, Weil disputes Cal-SLA's assertion that it is unfair and discriminatory not to extend time of use pricing to streetlighting customers.

The CEC opposes all measures that would reduce price responsiveness by masking prices and argues that all customers should be exposed to market prices to induce price responsiveness, which serve to create more effective markets. The CEC makes one exception for low income customers, which it believes should be allowed BPPs and recommends that subsidies to low income customers should be applied after customers have been exposed to prices to allow for price realization. The CEC maintains that UDCs should not be allowed

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[11] UCAN's brief does not specifically address whether it would allow continuation of existing BPPs.

to offer competitive services, especially since the overall question of the role of the UDC has yet to be determined. In addition, the CEC points out that mechanisms to smooth prices could result in higher prices as customers pay interest on the amount deferred to subsequent billing periods. Commonwealth supports the CEC's position on rate capping.

In response, PG&E argues that the Commission should not rely on ESPs to offer bill smoothing products. In addition, PG&E notes that although the CEC opposes all price diluting measures, it does acknowledge the need for bill smoothing for low income customers. PG&E reiterates its argument that expansion of the BPP to non-residential customers will be costly and cumbersome.

F. Discussion

We find that it is premature to adopt a procurement PBR mechanism, either for PG&E or for SDG&E, until the role of the UDC in procurement is determined by this Commission. We declare that the mandatory buy requirement should no longer be confined to just the CalPX, but should be extended to any qualified exchange during the transition period. Permitting use of qualified exchanges other than the CalPX may be beneficial for development of an exogenous benchmark for use in consideration of possible future PBR mechanisms. In addition, we determine that consumers must be aware of the price signals provided by the market. We therefore reject PG&E's rate capping proposals. We agree with TURN that balanced payment plans, which each utility already has in place, offer a bill smoothing effect for residential customers and still allow these customers to be exposed to price signals. We also find that the UDCs may not extend these payment plans to street lighting customers or expand these options in any way until we make a determination as to the role of the utility in the new regime. We are confident that the market will evolve to develop various services and options that will further enhance competition, while dampening price volatility. We discuss each of these determinations below.

We also believe it is important to reiterate our intentions now for the end of the transition period so markets and competition can evolve accordingly. We reaffirm our decision in D.95-12-063 that post transition, we will remove any and all mandatory buy requirements. Post transition, if UDCs have a procurement role, they may procure energy however and wherever the best price for ratepayers may be obtained. We defer the mechanism for ensuring ratepayers do receive the best price to our anticipated proceeding for determination of the procurement role of the UDCs.

~~We find that it is premature to adopt a procurement PBR mechanism, either for PG&E or for SDG&E and that the mandatory buy requirement should no longer be confined to just the CalPX, but should be extended to any qualified exchange during the transition period. In addition, we determine that consumers must be aware of the price signals provided by the market. We therefore reject PG&E's rate capping proposals. We agree with TURN that balanced payment plans, which each utility already has in place, offer a bill smoothing effect for residential customers and still allow these customers to be exposed to price signals. We also find that the UDCs may not extend these payment plans to street lighting customers or expand these options in any way until we make a determination as to the role of the utility in the new regime. We are confident that the market will evolve to develop various services and options that will further enhance competition, while dampening price volatility. We discuss each of these determinations below.~~

~~We also believe it is important to declare our intentions now for the end of the transition period so markets and competition can evolve accordingly. We determine that post transition, we will remove any and all buy requirements. Post transition, the UDCs may procure energy however and wherever the best price for ratepayers may be obtained.~~

1. Procurement Practices

~~We recognize that during the rate freeze period, the utilities have had incentives to minimize the cost of procurement for bundled customers. This is true because of the headroom concept and the residual calculation of the CTC, discussed above. Any procurement practices that unnecessarily increase the energy charge to customers will necessarily decrease the amount of headroom available, and thus, the amount of revenues available to apply to transition cost recovery. Because CTC revenues will no longer be calculated or collected on a residual basis, this incentive will end when the rate freeze ends. Several approaches to solve this dilemma have been proposed to maintain incentives for the utilities to continue to make economical purchases on behalf of bundled customers: 1) adopt procurement PBR mechanisms, 2) prescribe procurement guidelines, 3) maintain the mandatory buy requirement, and 4) undertake *ex post* reasonableness reviews.[12]~~

We recognize that during the rate freeze period, the utilities have had incentives to minimize the cost of procurement for bundled customers. This is true because of the headroom concept and the residual calculation of the CTC, discussed above. Any procurement practices that unnecessarily increase the

~~[12] Some parties have proposed that default provider status be examined and modified. This approach is not within the scope of this proceeding.~~

energy charge to customers will necessarily decrease the amount of headroom available, and thus, the amount of revenues available to apply to transition cost recovery. Because CTC revenues will no longer be calculated or collected on a residual basis, this incentive will end when the rate freeze ends.[13] Several approaches to ensure just and reasonable rates have been proposed to maintain incentives for the utilities to continue to make economical purchases on behalf of bundled customers: 1) adopt procurement PBR mechanisms, 2) prescribe procurement guidelines, 3) maintain the mandatory buy requirement, and 4) undertake *ex post* reasonableness reviews.[14]

~~We are not convinced that it is either reasonable or prudent to adopt a procurement PBR mechanism at this time. Although a PBR model may provide incentives for the UDC to reduce procurement costs, we are not convinced that it avoids perverse incentives or properly aligns the UDCs' interests with customers' interests. Furthermore, we are not convinced that the UDCs could purchase electricity at prices that are consistently lower than the PX price, as both the CEC and TURN point out. Furthermore, we have not ruled as a Commission on the role of the UDC in supplying default customers. We will not implement mechanisms that may have the perverse incentive of encouraging the UDC to retain customers by using unfair practices, e.g., using resources of the monopoly distribution company to retain customers for the procurement function.~~

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13 However, the utilities should still have the incentive implied by the requirement to charge just and reasonable rates (PU Code § 451).

14 Some parties have proposed that default provider status be examined and modified. This approach is not within the scope of this proceeding.

We are not convinced that it is either reasonable or prudent to adopt a procurement PBR mechanism now before we have determined whether the utilities will continue to have a procurement role. Although a PBR model may provide incentives for the UDC to reduce procurement costs, we are not yet convinced that it avoids perverse incentives or properly aligns the UDCs' interests with customers' interests. Furthermore, we have not ruled as a Commission on the role of the UDC in supplying default customers. We will not implement mechanisms that may have the perverse incentive of encouraging the UDC to retain customers by using unfair practices, e.g., using resources of the monopoly distribution company to retain customers for the procurement function.

~~We recognize that such practices may well be difficult to prove and that regulatory oversight of a procurement PBR mechanism would be fraught with difficulties. As the CEC explains, the theory of a valid PBR rests on the identification of an appropriate benchmark that cannot be manipulated. With properly-designed incentive regulation, once the benchmark is established, little regulatory oversight is required because the interests of shareholders and ratepayers are properly aligned. That is not the case here. Despite the contentions of the settling parties as to the various affiliate transaction rules this Commission has implemented, it would be very difficult for the Commission and other parties to monitor all the transactions that may take place outside of the PX.~~

We recognize that such practices may well be difficult to prove and that regulatory oversight of a procurement PBR mechanism could be fraught with difficulties. As the CEC explains, the theory of a valid PBR rests on the identification of an appropriate benchmark that cannot be manipulated. With properly-designed incentive regulation, once an exogenous benchmark is established, little regulatory oversight is required because the interests of shareholders and ratepayers are properly aligned. That is not yet the case here. Despite the contentions of the settling parties as to the various affiliate transaction rules this Commission has implemented, it may be difficult for the Commission and other parties to monitor all the transactions that may take place outside of any FERC-regulated exchanges.[15] Thus, it is necessary to adopt standards for qualified exchanges before proceeding to consider any PBR mechanism.

~~Furthermore, we are not persuaded that it is reasonable or in the public interest to adopt the settlement at this time. We agree with SDG&E that we should not be swayed because of the number of opposing parties. However, we do not agree that the diversity of opinions regarding the settlement necessarily reflects "an intrinsic fairness and balance of result." (Joint Reply Comments on Settlement, p. 7.) We cannot ignore the fact that a wide range of interests oppose the settlement and do not believe that this purported middle ground approach is in the public interest at this time. Again, we believe that the market is not sufficiently developed to support this approach. Furthermore, we do not intend to prejudge any action that this Commission or the Legislature might take with regard to default providers or the role of the UDC. We decline to implement an administrative mechanism that could have a chilling effect on competition.~~

[15] Furthermore, we share ARM's concerns that at present the UDCs can manipulate current markets by deliberately under- or over-scheduling in CalPX markets so as to be able to participate in the ISO's imbalance energy markets. As also noted by TURN, the total cost of the commodity can vary substantially dependent upon the distribution of purchases among the four markets.

Furthermore, we are not persuaded that it is reasonable or in the public interest to adopt the settlement at this time. We agree with SDG&E that we should not be swayed because of the number of opposing parties. However, we do not agree that the diversity of opinions regarding the settlement necessarily reflects "an intrinsic fairness and balance of result." (Joint Reply Comments on Settlement, p. 7.) We cannot ignore the fact that a wide range of interests oppose the settlement and do not believe that this purported middle ground approach is in the public interest at this time. Again, we believe that the market is not sufficiently developed to support this approach.[16] Furthermore, we do not intend to prejudge any action that this Commission or the Legislature might take with regard to default providers or the role of the UDC. We also decline to implement an administrative mechanism that could have a chilling effect on competition.

~~We acknowledge UCAN's concern that the competitive market is not fully developed for small customers. UCAN believes that SDG&E needs to have the proper incentives to purchase electric service for its bundled customers for the short-term, but recognizes that this may not be necessary in the long-term. We do not wish to adopt short-term fixes now that may or may not provide proper incentives to SDG&E. In addition, we decline to fix an end-point of 2004 for maintaining 80% of SDG&E's procurement through the CalPX.~~

~~When SDG&E's gas procurement PBR was adopted in 1993 (D.93-06-092, 50 CPUC 2d, 185), it was adopted as an experiment and was~~

[16] Development of the wholesale market prior to the end of the transition is one compelling reason to open the mandatory buy requirement to any qualified exchange now, as discussed infra at II.F.1. Enhancing competitiveness in the wholesale market will foster the economic health of retail markets, inuring to the benefit of ratepayers.

~~developed through a collaborative approach. We note that at this point in gas basin deregulation, gas procurement competition was well developed and several robust, exogenous benchmarks existed that parties agreed were reliable. In other words, gas basin competition was much more mature than the state of electric procurement competition is today. Furthermore, we are not sure that this experiment will enable the Commission to determine its success when completed or that the experiment itself does not present unreasonable risks. Instead, as Farm Bureau recommends, it is reasonable to require continued purchasing from the CalPX and related markets (including day-ahead, day-of, block forward, and the ISO imbalance energy markets) to better understand the impacts of this approach. However, we also are convinced that other viable exchanges now exist or are forming that can be equally as reliable as the CalPX and could provide lower costs to be passed through to bundled customers. Therefore, we believe that during the transition period, the UDCs may procure energy through any qualified exchange.[17] It would be disingenuous to reject rate capping proposals to protect consumers from market forces (see III.F.2. infra) yet protect our regulatory creation, the CalPX, from those same market forces. Once the market is more robust and we have articulated our approach to the default provider issue and the role of the UDC, it may be beneficial to adopt~~

[17] A qualified exchange is one that provides equal nondiscriminatory access and a mechanism for timely price transparency. In order to be deemed a qualified exchange, an advice letter must be filed by the UDCs (jointly or separately) which details how these criteria are being met. The Commission will then determine if the exchange should be qualified for UDC purchases or whether further criteria must be met to obtain qualification. We intend that such advice letters be processed expeditiously to facilitate evolving competitive markets and market options.

~~procurement incentives. If so, we would recommend a collaborative approach with clearly articulated goals and objectives.~~

~~We agree with CUE that a reasonableness review of procurement practices would be a regulatory nightmare. However, we are not convinced that, as currently proposed, the procurement PBR mechanisms are any more attractive. By expanding the mandatory buy requirement to any qualified exchange, we resolve these concerns by deeming the wholesale price of any qualified exchange reasonable.~~[18]

~~We also believe that we should no longer delay announcing our stance on the mandatory buy requirement post transition period. While we do not intend to prejudge our §390 proceedings or our upcoming consideration of the role of the UDC post transition, market participants need certainty now in order to plan for and achieve robust competition post transition. Once we issue our decision on the role of the UDC, if further modification of today's decision is necessary to protect ratepayer interests, we can sua sponte make such modifications. Waiting until close to the end of the transition period to start a review of our post transition course is too much regulatory lag in the midst of faster moving, evolving competitive market entrants. We must remove barriers to their entry as soon as possible.~~

~~In the PPD this Commission set a course toward competition. The purpose of the transition period was to allow markets to evolve so we arrived at that destination by the end of March, 2002. Stating now how we intend to deal~~

[18] As we discuss in greater detail later in this decision, whether or not there the cost of the PX energy charge (and the corresponding PX credit to direct access customers) should include any additional costs is being considered in A.99-08-022 *et al.*, the 1999 Revenue Adjustment Proceeding (RAP).

~~with the mandatory buy requirement as of April 1, 2002 will further spur competitive market solutions which will be in place at that time.~~

~~At the time of the PPD we did not envision the advent of such organizations as the APX. Its creation is evidence that market solutions can evolve to improve on regulatory ones. We wish to foster such market based creations. Allowing use of qualified exchanges during the transition period will be a spur towards their more robust development by the end of the transition. The PPD permits present use of options other than the CalPX, as well as the use of bilateral contracts, by entities other than the UDCs. Now is the time to declare we are leveling the playing field for all market players post transition. While we commend the CalPX on its development of new products, such as the forward markets, we are convinced that allowing competitors and potential competitors to the CalPX to develop further beneficial solutions based on a full range of competitive needs is in the best interest of ratepayers. Competitive exchanges and prudent use of bilaterals should place further downward pressure on CalPX prices. It may also produce more innovative products which will create increased levels of demand responsiveness to foster the health of wholesale markets. Once we have determined the role of the UDC, we can then examine the state of development of competitive exchanges and may choose to reconsider whether there is a need for procurement PBRs and bands of deemed reasonableness for procurement mixes. If competition is as robust as hoped, no regulatory scrutiny will be needed.~~

~~Therefore, we find that effective immediately at the end of the transition period, the mandatory buy requirement for the UDCs must be eliminated. Full and robust competitive market forces should produce the best rates for all classes of customers. If we are correct, this would mean an end to regulatory scrutiny of commodity purchases. We are cognizant that a court~~

~~could therefore find the State action doctrine is no longer applicable to the generation procurement function of the utility. In such a way, all players in the new competitive generation market will be placed on a level field of antitrust scrutiny.~~

We acknowledge UCAN's concern that the competitive market is not fully developed for small customers. UCAN believes that SDG&E needs to have the proper incentives to purchase electric service for its bundled customers for the short-term, but recognizes that this may not be necessary in the long-term. We do not wish to adopt short-term fixes now that may or may not provide proper incentives to SDG&E. In addition, we decline to fix an end-point of 2004 for maintaining 80% of SDG&E's procurement through the CalPX. Instead, as noted infra, the end point is much sooner than 2004.

When SDG&E's gas procurement PBR was adopted in 1993 (D.93-06-092, 50 CPUC 2d, 185), it was adopted as an experiment and was developed through a collaborative approach. We note that at this point in gas basin deregulation, gas procurement competition was well developed and several robust, exogenous benchmarks existed that parties agreed were reliable. In other words, gas basin competition was much more mature than the state of electric procurement competition is today. Furthermore, we are not sure that this experiment will enable the Commission to determine its success when completed or that the experiment itself does not present unreasonable risks. Instead, as Farm Bureau recommends, it is reasonable to require continued purchasing from the CalPX and related markets (including day-ahead, day-of, block forward, and the ISO imbalance energy markets) to better understand the impacts of this approach. But we are also convinced that other viable exchanges now exist or are forming that can be equally as reliable as the CalPX, could provide lower costs to be passed through to bundled customers, and assist in establishing an exogenous benchmark. In making such a statement we are not criticizing the CalPX, but are instead recognizing fundamental economic theory.

As asserted by Weil, the Commission should now let the buy requirement expire because the justification for it has ended. As Weil observes, the Commission's fundamental goals for the buy requirement were price transparency, mitigation of market power, and reduction of the regulatory burden of CTC reasonableness revenues. Weil posits correctly that, four years after the PPD, "real California markets now feature adequate price transparency outside the CalPX." (Testimony of Weil, Exh. 65 at 2.) He points to NYMEX data for monthly on-peak power blocks, Dow Jones data for daily firm and nonfirm, on-peak and off-peak prices and volumes, data collection and publication by Pricewaterhouse Coopers, California Energy Makrets, Reuters, Bloomberg, Megawatt Daily, Power Markets Week, and Energy Market Report, and the ability of partcipants in the APX to have immediate access to prices and volumes of anonymous, real-time tranactions made through the APX.[19] We concur with Weil's assessment that, as the Commission anticipated in the PPD, market participants have developed means of gaining access to pricing information and are able to compare the advantages and disadvantages of reliance on the CalPX.[20]

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[19] The APX currently publishes prices for its green power products comprising 70% of its power transactions. It will publish nongreen transactions once volumes are sufficient to allow anonymity. (Tr. Cazelet at 1328-29.)

[20] We observe that the CEC concedes that it does not advocate restricting purchases to the CalPX, as long as all purchases are made in an open, public market where price transparency is evident. It notes that, in its testimony throughout this proceeding, "references to the PX are meant to decribe such an open, public market where price transparency is evident in its generic sense without confining it to the California Power Exchange." (Testimony of Jaske Exh. 85 at 8-9.) In addition, ARM posits that the

Footnote continued on next page

We agree with SDG&E that unless volumes were to drop precipitously, less volume in the CalPX would not correlate to less transparent price discovery. As he opines, price transparency has much more to do with the similarity of the underlying terms of trade and publishing of the prices at which trades take place. (Testimony of Sakarias, Exh. 38 at 3.) We concur with his assessment of the CalPX's argument that its thin hour-ahead market and other existing limitations require us to continue to support its experimental market: "The real question is whether there is a market for these services. If they are not needed, they should be allowed to die. We should not be putting PX services on a heart-lung machine if the market is saying, it is time to pull the plug." (Id. at 15.) We also find, as asserted by the CEC's witness Jaske, that the continuance of the buy mandate is a factor that prevents the APX getting the liquidity it needs to permit anonymous publication of market clearing prices. (Tr. at 1754-55.) Thus we reject CalPX's argument that opening up the mandatory buy requirement to other qualified exchanges will endanger the liquidity and depth of its markets. Price transparency has nothing to do with deep or liquid markets. It has to do with timely public disclosure.

We also agree with Weil that the CalPX price information's value is declining over time. The UDCs are divesting generation to those exempt from the mandatory buy requirement. As he notes, as the CalPX market share declines, market participants will naturally look elsewhere for price and volume data. Therefore, we conclude that the need for price transparency no longer

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CalPX's BFM affects its competitive transparent price and destroys its value as a signal to competitors. (Tr. Michaels at 1429.)

requires that the CalPX be the sole qualified exchange for purposes of the mandatory buy requirement.

We concur with Weil's assessment that our link of price transparency to mitigation of market power has weakened due to utility divestiture of generation. We note that FERC has not expressed concerns regarding buy side market power. Instead, market power concerns have shifted to the new competitive generation owners which are not subject to the mandatory buy requirement. Therefore, the market power mitigation underpining of the CalPX monopoly for purposes of the mandatory buy requirement has eroded.

In addition, we agree with Weil's assessment that changes in the mandatory buy requirement should have no impact on our regulatory burden. As he notes, even with the mandatory buy linked to the CalPX, utilities still have choices to make among different services offered by the CalPX in the day-ahead, hour-ahead and various BFMs and in the ISO imbalance energy markets. Many of these markets were not envisioned within the scope of the PPD's creation of the CalPX and ISO, but have since evolved based on market forces and demand.[21] Indeed, the CalPX BFM is not bilateralized like the day-ahead auction set forth in the PPD. For this reason, we reject CalPX arguments that its matching of supply to demand is a requisite for any California clearinghouse. The Commission is already faced with multiple markets and there is no reason regulatory mechanisms cannot evolve to allow for them. We are convinced the regulatory burden will not be increased by embracing similar markets provided

[21] See Testimony of ARM, Exh. 69 at 25. (The PPD only called upon the CalPX to manage an hour-denominated day-ahead market.)

by qualified exchanges. Thus, we are convinced that the compelling reasons for creation of the CalPX as the sole qualified exchange for purposes of the mandatory buy requirement have been mooted by time and market forces.

We concur with ARM's assessment that there is plenty of competition in today's market and that opening up trading "will supercharge retail access, it will supercharge competition generation, and most importantly it will supercharge competition in trading, which is now being stifled by the current mandate." (Tr. Cazelet at 1343.)

Finally, we find one of the arguments made by the CalPX to rationalize entrenching its current monopoly to instead provide a compelling rationale for breaking it. The CalPX contends that the market needs time to mature so that the CalPX day-ahead, hour-ahead and ISO real-time markets will be quite close in price. It notes that if they differ by more than a small amount, buyers and sellers will shift their trades between these markets until the price gap closes. The CalPX notes that such arbitrage is an essential part of any efficient market structure. It urges us not to impede the movement of trades between these markets so as not to interfere with market efficiency. (Testimony of Kritikson, Exh. 75 at 9.) Yet, by perpetuating the monopoly of the CalPX, we would impede market efficiencies achieved through arbitrage among several qualified exchanges.[22] The result would be lower prices for bundled customers set through arbitrage in a variety of markets rather than one artificial set of prices arrived at through circumscribed arbitrage in one market. Thus, market efficiency dictates an expansion of the mandatory buy requirement to other qualified exchanges.

[22] We take official notice of the upward trend of CalPX prices.

We define a qualified exchange is one that provides continuous trading in a bid/ask type market, equal nondiscriminatory access and a mechanism for timely, anonymous price transparency. Its market-clearing price algorithm must be publicly available and its prices must be published at least as frequently as the CalPX now publishes. It must also be subject to audit and record verification, have a compliance unit, and offer similar unambiguous terms of trade. A qualified exchange cannot be owned by a UDC or its affiliate, all or in part. In order to be deemed a qualified exchange, an advice letter must be filed by the UDCs (jointly or separately) which details how these criteria are being met. The Commission will then determine if the exchange should be qualified for UDC purchases. We intend that such advice letters be processed expeditiously, within a 60-day period, to facilitate evolving competitive markets and market options.

Therefore, we believe that during the remainder of the transition period, the UDCs may procure energy through any qualified exchange. It would be disingenuous to reject rate capping proposals to protect consumers from market forces (see III.F.2. infra) yet protect our regulatory creation, the CalPX, from those same market forces. Once the market is more robust and we have articulated our approach to the default provider issue and the role of the UDC, it may be beneficial to adopt procurement incentives if UDCs continue to have a procurement role. If so, we would recommend a collaborative approach with clearly articulated goals and objectives.

We agree with CUE that a reasonableness review of procurement practices would be a regulatory nightmare. However, we are not convinced that, as currently proposed, the procurement PBR mechanisms are any more attractive. By expanding the mandatory buy requirement to any qualified exchange, we resolve these concerns by deeming the wholesale price of any qualified exchange reasonable.[23]

We also believe that we should no longer delay reiterating our stance on the mandatory buy requirement post transition period as set forth in the PPD. While we do not intend to prejudge our §390 proceedings or our upcoming consideration of the role of the UDC post transition, market participants need certainty now in order to plan for and achieve robust competition post transition. Once we issue our decision on the role of the UDC, if further modification of today's decision is necessary to protect ratepayer interests, we can sua sponte make such modifications. Waiting until close to the end of the transition period to start a review of our post transition course is too much regulatory lag in the midst of faster moving, evolving competitive market entrants. We must remove barriers to their entry as soon as possible.

In the PPD this Commission set a course toward competition. The purpose of the transition period was to allow markets to evolve so we arrived at that destination by the end of March 2002. Stating now how we intend to deal with the mandatory buy requirement as of April 1, 2002 will further spur competitive market solutions in order for them to be in place by that time. We concur with Weil that in the PPD the Commission has already ordered that the mandatory buy requirement will expire March 31, 2002.

At the time of the PPD we did not envision the advent of such organizations as the APX or NYMEX so quickly.[24] Their creation is evidence that

[23] As we discuss in greater detail later in this decision, whether or not there the cost of the PX energy charge (and the corresponding PX credit to direct access customers) should include any additional costs is being considered in A.99-08-022 *et al.*, the 1999 Revenue Adjustment Proceeding (RAP).

market solutions can evolve to improve on regulatory ones. We wish to foster such market-based creations. Allowing use of qualified exchanges during the transition period will be a spur towards their more robust development by the end of the transition. The PPD permits present use of options other than the CalPX, as well as the use of bilateral contracts, by entities other than the UDCs. Now is the time to declare we are leveling the playing field for all market players post transition and that we meant what we said in the PPD.

In the PPD's Ordering Paragraph 5, we declared that, "At the end of the transition period, when determination of assets which qualify for recovery under the competition transition change has been finalized, the utilities shall be released from any mandatory requirement to bid into or purchase from the Power Exchange." (D.95-12-063 at 219-220 (emphasis added).) We again affirmed our intent to lift the buy requirement effective March 31, 2002 in D.99-07-018. In rejecting Edison's application for a pilot program pre-rate freeze termination for purchases outside the CalPX, we declared "The Preferred Policy Decision allows for the types of purchases Edison describes, but only after the transition period concludes." (Id. at 8.)

While we commend the CalPX on its development of new products, such as its variety of forward markets, we are convinced that allowing competitors and potential competitors to the CalPX to develop further beneficial solutions based on a full range of competitive needs is in the best interest of ratepayers. Direct access customers already have the benefit of using any other exchange. Expanding options for bundled customers now will better set the stage for post transition. Post transition, competitive exchanges and prudent use

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[24] For example, the APX was founded in 1996.

of bilaterals should place further downward pressure on CalPX prices. It may also produce more innovative products which will create increased levels of demand responsiveness to foster the health of wholesale markets. Once we have determined the role of the UDC, we can then examine the state of development of competitive exchanges and may choose to reconsider whether there is a need for procurement PBRs and/or bands of deemed reasonableness for procurement mixes.

Therefore, we find that effective immediately at the end of the transition period, the mandatory buy requirement for the UDCs must be eliminated. Full and robust competitive market forces should produce the best rates for all classes of customers.

a. The Scope of the Proceeding as to Procurement Practices

We believe that our actions today regarding the PX and the mandatory buy requirement are within the scope of this proceeding and do not contravene PU Code § 1708.[25] As noted in the March 11, 1999 Scoping Memo and Ruling of Assigned Commissioner (ACR) among the ratemaking issues within the scope of this proceeding were whether utilities should utilize "balancing accounts for power cost recovery, whether other regulatory mechanisms provide better incentives, and whether the Commission should conduct reasonableness revenues of utility power purchases." (ACR mimeo. at 2.) The ACR also concluded that "the Commission must determine how the generation rate will be established . . .and the conditions under which the rate will change." (Id. at 3.)

[25] Section 1708 declares that the Commission "may at any time, upon notice to the parties, and with opportunity to be heard as provided in the case of complaints, rescind, alter, or cancel any order or decision made by it."

The ACR also declared that "The scope of this proceeding will include broad rate design policy and rate design matters which are integral to ending the rate freeze and the development of post transition ratemaking." (Id. at 4.) The ACR declared that the Commission did not anticipate that these applications would explore the wide range of market structure issues, such as the role of the utilities, prospects for their self-dealing and utility monopsony power. However, the ACR stated that "The parties may, however, justify or oppose a proposal on the basis that it would compromise or promote competitive goals as long as the proposal is otherwise within the scope of the proceeding." (Id.) Many parties did so.

Taken all together, we believe that a proposal to open up the mandatory buy requirement, before the end of the transition period, to other qualified exchanges is a matter integral to the ending of the rate freeze and the development of our post-transition ratemaking. More data from more exchanges will assist the Commission in making its final determination of post-transition rates under the cost allocation methodology set forth later in this decision. The APX in its testimony and briefs in this proceeding has advocated that breaking the PX trading monopoly will promote Commission competitive goals, which falls squarely within the parameters of the ACR. The APX articulated a preference for totally eliminating the mandatory buy requirement or at least to have qualified markets for trading. (Tr. Cazelet at 1343.) The APX testimony also links to our examination of the generation rate and the conditions under which it will change as delineated in the ACR.[26] The APX has also advocated for

[26] We also note that, as part of its EPIM proposal, PG&E proposed making purchases from the APX.

an end of the mandatory buy requirement for SDG&E effective upon the end of its rate freeze. Weil and WPTF have advocated for letting the mandatory buy requirement expire. The UDCs and Weil concur that the rate freeze's end signals the end of a UDC's transition period. We also observe Dynergy recommended that the CalPX be only one of many available markets post rate freeze and argued that the structure of the PX does not reflect open markets truly. Finally, the APX rebuttal testimony is squarely on point with our conclusion that linking the buy requirement only to the PX creates market inefficiencies and stifles innovation and was not extant at the time of the PPD. Therefore, we conclude that in today's order we are acting within the scope of this proceeding as perceived by the parties regarding the CalPX and the mandatory-buy requirement.

We also find that our further expansion of the PPD's mandatory-buy requirement to qualified exchanges does not violate PU Code § 1708. We are acting within the scope of the ACR and have given further notice to the parties by publishing this order two times for comments, the second time sending it to the entire electric restructuring service list in R.94-04-031/I.94-04-032. We have reviewed all comments and reply comments and find no assertions that require us to hold a hearing on this policy matter.[27] "[C]hanges in regulatory policy are hardly shocking, they occur with two-week regularity as the Commission issues decisions that continue to mold, apply, and implement the changes affecting the electric industry." Re. San Diego Gas & Electric Co. 68 CPUC2d 434, 448 (1996).

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[27] See, e.g. Re Mobile Telephone Service and Wireless Communication, 59 CPUC2d 91, 96-98 (1995). We also note that, as in Mobile Telephone, we have since the PPD refined our thinking to permit use of PX block forward markets, a clear expansion of the PPD mandatory-buy, via advice letter processes.

(Changing QF policy issues in light of electricity deregulation.) The Commission has observed that, "We are permitted to refine our thinking between one decision and the next." In Re Pacific Telesis Group, 59 CPUC2d 54, 56 (1995) (revising 18% interest rate in 1993 decision to 3.4% interest rate in 1995 decision). We agree that "We clearly have the discretion to change our views after the passage of several years, during which additional proceedings have taken place...." (Id. at 57.) As noted supra, in 1995, when we issued D.95-12-063 (64 CPUC2d 1), no entity similar to the CalPX existed. Therefore, we had to create it. Thereafter, the APX was founded in 1996 and other entities followed, spurred by the opportunities arising from competitive markets. In the interim, we have authorized UDC purchases from various CalPX block forward markets and the ISO imbalance market, none of which were envisioned by the PPD. Therefore, 5½ years later, we continue to refine our thinking regarding the CalPX's monopoly regarding the mandatory-buy requirement and conclude it is appropriate in this proceeding to expand the requirement if other qualified exchanges exist.

2. Rate Capping

We reject PG&E's proposal that it is necessary to cap rates in order to protect residential and small commercial customers from potential price volatility and corresponding rate increases. PG&E believes that these customers expect rate decreases at the end of the rate freeze and that such an unexpected increase could result in "major regulatory and political problems for regulators and the regulated alike." (PG&E Opening Brief, p. 13.)

Although PG&E is worried about possible political ramifications, we did not initiate electric restructuring in order to shield consumers from the market. We agree with Weil and TURN that customers need accurate price signals in order to react and protect themselves against periodic price spikes. We are persuaded that masking prices results in incomplete and inefficient market structure and system demand, and compromises system reliability. Only through accurate price signals can customers understand how their usage impacts the system and make economically efficient choices. The price of electricity fluctuates; thus far, consumers have not been impacted by these fluctuations. Consumers should have the opportunity to respond to such market signals as they see fit, which may include shifting load, conserving power, or procuring the commodity through direct access.

As the market evolves, we would expect ESPs to offer products and services that will allow greater means to smooth bills. Until we determine the role of the UDC in the new market, it is premature to allow the UDC to offer new commodity products and services, other than those already authorized or under consideration in other proceedings (see discussion regarding load retention discounts, below~~.~~). Therefore, we will limit the new products offered by the UDCs to those already authorized, until there is a decision on the role of the UDC. It is reasonable to allow the utilities to continue to offer BPPs to their residential customers. We will not expand this program to streetlighting customers. We agree with UCAN, the CEC, and various competitors that this is a problem for which the marketplace can find a solution. Various programs are already in place to assist low-income customers with their energy bills; e.g., California Alternative Rates for Energy (CARE) provides a rate discount. We see no reason to provide further protection from volatility at this time.

3. Definition of the Transition Period for Buy-Sell Requirement

In the Preferred Policy Decision, the Commission required that the UDCs buy and sell power through the CalPX during the transition period. At that time, the Commission anticipated that the transition period would last five years. The fundamental reasons for this approach were the Commission's goals of consumer protection and the development of a deep and transparent market for power. The Preferred Policy Decision states:

> These goals of consumer protection, ensuring the integrity of the compensation request protected by the competition transition charge, reduction of the nature and complexity of future regulation, and nurturing the advent and maturing of the market signals suggests that it is useful to think of participation in the Power Exchange in three distinct time frames:
>
> 1. the initial period when there is little if any experience with market conditions and functions;
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> 2. the five-year period identified as the transition between the regulatory order which is passing and the competitive climate we seek to foster; and
>
> 3. the post transition period.
>
> <u>A refusal to make this distinction imposes the risk of withholding support for infant mechanisms as yet untested by market participation or perpetuating the presence of such supportive structures after customer and supplier sophistication has rendered them unnecessary</u>. (D.95-12-063, as modified by D.96-01-009, mimeo. at pp. 52-53, emphasis added.)

In addition, the Commission determined that allowing the utilities to opt for non-exchange, bilateral contracts, for sales and purchases, would jeopardize the price transparency and reliability of price signals, and the legitimacy of the competition transition charge. The Commission concluded that if the utilities opted to make the bulk of their purchases on behalf of full service customers through bilateral contracts, those customers most vulnerable to market power abuse would have no means of tracking electric power costs. The Preferred Policy Decision states:

> Beyond the issues of consumer protection and customer choice, there is the legitimacy of the competition transition charge and its acceptance as a non-bypassable obligation by all classes of users. The issue of generation assets alleged to be stranded would now be plagued with doubt and uncertainty at the precise time when this Commission would be seeking to ensure the acceptance and collection of a non-bypassable competition transition (sic). Again, complex and probing regulatory proceedings might eventually determine the reasonableness of these claims presented by our jurisdictional utilities but the time and delay would protract the transition period and move us away from reliance upon market mechanisms. (*Id.*, mimeo. at pp. 59.)

In this proceeding, we must determine whether the utilities should be released from the buy requirement if stranded costs have been recovered before the end of the four-year transition period. We acknowledge that any generation unit divested to a non-affiliated new owner is free of any obligation to bid into the Exchange (*Id.* at p. 53.)

The FERC granted SDG&E partial release of its "sell" obligation as it maintains jurisdiction over wholesale transactions. Under the Federal Power Act, FERC has jurisdiction over sales for resale. SDG&E requested authorization to sell power at market-based prices from any source of energy into all markets, including the PX. SDG&E did not ask FERC to modify the buy requirement, only the sell requirement. The September 1999 FERC Decision granted a very limited exemption from the mandatory sell requirement. The scope of this exemption is limited to sales from SDG&E power purchase contracts, and does not exempt any generation it owns or the wholesale commodity from in-system QF contracts. This authority does not reach any requirements this Commission may impose as to the retail services SDG&E provides to its bundled service customers. Therefore, pursuant to our authority over utility energy procurement for retail load, illustrated, for instance, in the series of cases establishing the so-called "Pike County" doctrine,[28] it is for this Commission to decide when and under what conditions to terminate the mandatory "buy" requirement.

While the specific rate freeze period applies to individual utilities and represents a period of time during which the utilities can recover stranded costs, that was not the sole objective of establishing the industry-wide transition period. This period is a time in which the market is developing and evolving, constituting a progression from a regulatory regime to one where competitive market forces determine prices. A fundamental component of that changeover hinges on the development of a deep, transparent, reliable commodity spot market. This development will be fostered by use of either the CalPX or any qualified exchange. The Commission anticipated that by the end of this period, the market would be more viable, competitive, and increasingly sophisticated. The collection of a given amount of revenue to pay down sunk costs does not

[28] Under the Pike County doctrine, a series of state and federal cases have recognized the right of states to review the prudence of a utility's purchasing decisions. That is, the state cannot refuse to let the utility pass through its wholesale costs based on the unreasonableness of the wholesale rates. However, the state can decide that the utility's decision to pay the wholesale rates was unreasonable in light of the availability of more economical power from alternative sources. The Commission therefore has oversight of power purchases for retail sale. The basis of the "buy" requirement is the Commission's determination that utility purchases through the CalPX are deemed reasonable.

and cannot equate to a finding that California energy markets have reached a competitive state.

The Preferred Policy Decision determined that the fundamental objective of the buy-sell obligation is to create a market with adequate depth and liquidity to assure confidence and increase the number and sophistication of market participants. In addition, the requirement was meant to reduce regulatory burden during the transition period as well as provide integrity for the CTC collected from customers. It is pertinent that we look to the intention of the requirement and whether its reasoning remains valid. We believe it does with the addition of removing any barriers to also use ~~for~~ any qualified exchange.

The utilities remain the largest purchasers of power in California. The requirement that they make those purchases through the CalPX or any qualified exchange will attract participants to the market, which in turn will serve to increase market depth. If we were to terminate the buy requirement at this time, retail competition could be hampered. The presence of big buyers attracts generators and ESPs to the market serving to increase liquidity and depth. The buy obligation provides a more level playing field that maintains ESP confidence in the market. As more ESPs participate in the marketplace, more innovation and ingenuity in value-added services will result. As more qualified exchanges enter the market, more innovation and ingenuity in procurement practices will emerge.

As long as any utility continues to collect generation-related transition costs from its customers, it is our responsibility to ensure the integrity of that charge. During the rate freeze, the CTC is derived residually based on energy and other costs; therefore, the validity of the CTC charge is dependent on the reliability of the energy charge. In our view the best means of accomplishing the objective of protecting the integrity of the CTC charge for any utility is to continue the buy requirement until all three utilities have recovered generation-related stranded costs, i.e., until each has ended its respective rate freeze. This way the energy charge will be determined by a transparent market price. Therefore, we conclude that so long as any utility continues to collect generation-related stranded costs which are tied to the rate freeze period, PG&E, Edison, and SDG&E must continue to buy from the Cal PX or a mixture of the Cal PX and any other qualified exchange. This reasoning rests on the possibility that the withdrawal of all purchases from the Cal PX by any one utility ~~can~~ may compromise the market price, thus serving to jeopardize the integrity of the competition transition charge for the utilities that remain under a rate freeze. Therefore, we will order that all three utilities continue to purchase power from the Cal PX or a mixture of the Cal PX and any qualified exchange at least until the last utility has ended its rate freeze and ceased collecting generation-related transition costs.

As directed in D.99-10-057, PG&E and Edison must provide monthly forecasts of the rate freeze end once its remaining generation assets have been valued or it begins to record costs in the Accelerated Costs Account of the TCBA. PG&E and Edison must also make an advice letter filing with tariff language and preliminary statements three months prior to the earliest date estimated using the four PX price forecast scenarios. If the utilities do not end their rate freeze early, proposed methodologies and tariff provisions for ending the rate freeze will be filed in September of 2001, three months prior to the end of the rate freeze. In order to promote timely rate changes, we also required PG&E and Edison to file a supplement to this advice letter five days following the date upon which all the criteria for ending the rate freeze have been satisfied. The filing will provide the actual rates to be implemented after the rate freeze, as well as the ratemaking mechanisms authorized by D.99-10-057 and this order. The advice letter implementing rate changes will become effective within 30 days of the end of the rate freeze subject to Energy Division determining the advice letter is in compliance with this and subsequent decisions. These advice letters will serve to notify parties and this Commission of the end of the rate freeze for PG&E and Edison.

IV. Cost Allocation Issues

A. Allocation of Ongoing Transition Costs

Section 367 generally defines transition costs and establishes the time frame for recovery of uneconomic costs. Generation-related transition costs must be recovered by December 31, 2001, with certain important exceptions. These exceptions include the following:

- employee-related transition costs (which must be recovered no later than December 31, 2006);
- power purchase contract obligations (which continue for the duration of the contract);
- costs associated with any buy-out, buy-down, or renegotiation of such contracts (which also continue for the duration of the agreement);
- costs associated with contracts approved by the Commission to settle issues associated with the Biennial Resource Plan Update (BRPU) (which may be collected through March 31, 2002, provided that only 80% of the balance remaining after December 31, 2001 are eligible for recovery);
- costs associated with entities exempted from transition cost recovery as delineated in § 374 (which must be recovered by March 31, 2002, provided that only $50 million of any balance remaining after December 31, 2001 is eligible for recovery);

- and costs associated with repaying the rate reduction bonds may be recovered until the fixed transition amounts are recovered in full.

Much of the controversy in this proceeding has centered on how these ongoing transition costs are allocated and the statutory interpretation of § 367(e) *et seq.*

The utilities propose to allocate post rate freeze transition costs using a System Average Percentage Change (SAPC) methodology. FEA, Farm Bureau, State Consumers, and Large Users support the utilities' proposal. They argue that § 367(e)(1) mandates that transition costs, both during and after the transition period, be allocated as similar costs were allocated on June 10, 1996. Rates frozen at June 1996 levels were allocated using a full Equal Percent Marginal Cost (EPMC) methodology. The SAPC, a proxy for the EPMC, adjusts these rate components (derived using EPMC) for usage.

Large Users state that it is unlawful to change allocation methodologies because this approach would involve cost shifting in conflict with § 367(e)(1) and approve a different allocation than that in effect in June 1996. Parties in favor of continuing the SAPC methodology argue that § 367(e) is specific to "transition costs" and does not distinguish between uneconomic costs during or after the rate freeze. Ongoing transition costs, which are primarily QF and power purchase agreement costs, are designated transition costs and should be treated as such under § 367(e)(1). In addition they argue that pursuant to § 371(a), transition costs should be adjusted for usage, which is accomplished by the SAPC methodology.

State Consumers support the SAPC methodology for now, but acknowledge equity concerns with locking in allocation factors over the long term. These parties recognize that, over time, rates will continue to diverge from those in effect on June 10, 1996. This is especially so considering the many ratemaking proceedings before the Commission.

On the other hand, TURN and ORA argue that ongoing transition cost responsibility should be allocated using cents-per-kilowatt-hour, which is inherently a usage-based allocation methodology. They argue that transition cost obligations should be allocated as generation costs since they are generation-related uneconomic costs. TURN and ORA recognize that D.99-06-058 (the decision in the 1998 RAP) mandated a SAPC transition cost allocation methodology during the rate freeze to avoid unlawful cost-shifting. However, these parties argue that there is no prohibition against cost-shifting after the rate freeze ends.

TURN also proposed an alternative allocation methodology, based on customer class demand in the top 100 hours of the year, which has previously been used to allocate generation costs for PG&E. TURN states that such a demand-based allocator is necessary to reflect that shortage costs that lead to construction of generation are incurred in more than a single peak hour.

Farm Bureau states that if the Commission determines that the statute permits deviation from the SAPC methodology, it supports TURN's and ORA's cents-per-kilowatt-hour approach. However, it recommends that if that method is chosen, allocation should be applied on a system wide basis as opposed to each tariff within the rate groups on a pro-rata basis. ORA agrees that this is reasonable.

In D.99-06-058, the Commission determined that transition costs must be allocated using a SAPC methodology during the rate freeze since that is the method used to derive frozen rates. The primary question to be resolved in this proceeding is whether the allocation methodology can and should be changed after the rate freeze ends.

Section 367(e)(1) states that transition costs must:

> Be allocated among the various classes of customers…in substantially the same proportion as similar costs are recovered as of June 10, 1996.

Section 367(e)(3) establishes that the Commission shall retain existing cost allocation authority provided the firewall and rate freeze principals are not violated.

The proponents of maintaining the SAPC cost allocation methodology post-rate-freeze contend that there is no conflict between the §§ 367(e)(1) and (3). According to these parties, we cannot change the cost allocation methodology for transition cost recovery until all transition costs are collected, including those that the utilities are allowed to recover after the rate freeze.

We must interpret §§ 367(e)(1) (2), and (3) in a manner that harmonizes the statute, and makes sense in light of the language and intent of the statute as a whole. ~~Section 367(e)(3) is not made effective subject to the provisions of § 367(e)(1). Therefore, we agree with ORA's and TURN's position that the sections are in conflict. The Legislature provides us with little guidance as to whether the transition cost allocation provisions of Section 367(e)(1) were meant to extend beyond the rate freeze.~~

~~In order to give effect to each section, subsection, and word in Assembly Bill (AB 1890) (Stats. 1996, Ch. 854) we must interpret the transition cost allocation provisions of § 367(e)(1) as expiring with stranded cost recovery. That is, after the rate freeze the Commission retains its cost allocation authority, including ongoing transition cost allocation. Adopting this approach does not violate the rate freeze, nor does it violate the firewall principles in effect. This~~

~~interpretation is supported by the fact that over time rates will increasingly diverge from those in effect on June 10, 1996.~~

~~Indeed, in light of unbundling and the many ratemaking proceedings before the Commission this has already occurred and will continue to occur. If we were to read § 367(e)(1) literally and maintain the allocation method in place on June 10, 1996 for ongoing transition costs, decades into the future when the last QFs and power contracts end, we would still be allocating those costs based on a 1996 methodology. We do not accept that the Legislature intended such an absurd result.~~

~~The fact that the Legislature added § 367(e)(3) to AB 1890 is telling. Had the Legislature intended that the Commission have no cost allocation authority regarding such costs, this subsection would be unnecessary. Therefore, the fact that cost allocation can change post rate freeze is supported by language in § 367(e)(3).~~

~~The Legislature specifically provided that we retain existing cost allocation authority provided that the "firewall and rate freeze principles are not violated." This language indicates that post-rate-freeze, the Commission has broader discretion in that regard. That is, the firewall, which addresses exemptions and is not relevant to the allocation change under discussion, was established in § 367(e)(1). Therefore, the firewall reference in § 367(e)(3) relates back to (e)(1). Similarly, the reference to "rate freeze principles" refers back to the cost allocation provisions of § 367(e)(1). Rate freeze principles obviously cannot be violated once the rate freeze has ended. Since that is the only limitation in § 367(e)(3) on the Commission's cost allocation authority, the cost allocation provisions of § 367(e)(1) extend only until the rate freeze ends.~~

We agree with the various parties who assert that the statute as a whole requires transition costs to be allocated in substantially the same way as they are allocated now both until the rate freeze ends and after, until transition costs no longer exist. However, this does not mean that the Commission cannot change the allocation at all. The Section 367 (e)(1) use of the modifiers "substantially the same proportion as" must be given effect as well as all other words. Further, if the Commission's allocation methodology can be "substantially the same proportion as" the current (and 1996) allocation, the discretion inherent in that phrase must mean that some classes may pay more and some classes may pay less in either dollar or percentage terms, than they pay now.

The statute (§367(e)(2)) provides that no customer pays more due to transition cost allocation changes (except for direct access customers in certain circumstances). During the rate freeze, this clause leads to residual calculation of transition costs. However, its implication must be considered after the rate freeze. After the rate freeze, an allocation of transition costs which is "substantially similar to " – but not exactly the same as – today's EPMC allocation will raise some customer's costs and lower some other customer's costs. In order to take each part of the statute together, we must add the fact that overall rates will decrease after the end of the rate freeze. Therefore, it is possible to increase some customers's responsibility for transition costs (on a percentage basis) and still have the result of lower rates.

The statute (§367(e)(3)) allows the commission to retain its pre-1996 cost allocation authority, subject to certain conditions. Therefore, the commission may consider other cost allocation methodologies besides EPMC or SAPC, again as long as the constraints of §367(e)(1) and (2) are abided by. While not required, it is appropriate for us to explore our options.

We will not adopt the EPMC or SAPC method for post-rate freeze transition costs solely on the basis that these methods are consistent with the statute. Other methods are also consistent with the statute, and we wish to consider various allocation methodologies that take into account equity and economics as well as adherence to the law.

Continuing to allocate costs in a manner based on bundled rates is outdated and inconsistent with current ratemaking policies. The EPMC and SAPC methodologies derive from ratemaking approaches implemented when rates were fully bundled. While rates are frozen at June 1996 levels, it makes sense to allocate transition costs using an EPMC or SAPC because rates were fully bundled in 1996. Now that rates are unbundled and costs are assigned to general functions, it would be inappropriate and contrary to cost causation to continue to allocate transition costs after the rate freeze as though rates were still bundled. For this reason we believe the EPMC and SAPC allocation methodologies are inappropriate for allocating ongoing transition costs.

Transition costs are an unusual set of costs because they are the uneconomic costs of generation resulting from the onset of competition. Large Users argue that ongoing transition costs should not be allocated using a cents-per-kilowatt-hour allocation because the costs are not volumetric in nature as they do not vary with energy use. TURN and ORA argue that transition costs are appropriately assigned to generation since they are the uneconomic costs associated with that function. We agree with TURN and ORA Transition costs should be allocated based on energy consumption because the costs are most appropriately assigned to the generation function. Again, this methodology is consistent with our policy of unbundling rates and functionalizing costs. Further, allocation of costs based on energy consumption is consistent with our long- standing principle of allocation by cost causation.

Costs vary based on time of use; put simplistically, the market cost (the PX price) for energy is generally lower in the middle of the night than in the middle of the day. Costs also vary based on season and other factors. To a certain extent, rates reflect these cost differences. Customers with time-of-use meters and real-time meters receive price signals that correspond (more or less) to the changes in costs and prices over time. Even residential customers without sophisticated meters currently see prices that vary between season, based on cost and market differences between season.

An allocation methodology for generation-related transition costs should take into consideration the variances in generation costs over time. The current EPMC method of allocation for transition costs does not do this, as it allocates costs based on systemwide costs instead of generation costs. Further, it allocates transition costs based on a method in existence in 1996 (and from costs from earlier years) that likely has little or no relation to costs today. At the same time, the equal cents per kwh allocation method fails to recognize that different customer classes purchase power at different times on average. Certainly, it cannot be true that each class has the same load curve, thus each class cannot be seen as causing the same generation costs. A theme throughout this decision is to expose customers to market forces e.g., by rejecting price cap proposals and requiring hourly data be used to bill customers on hourly meters. Cost allocation should likewise align with actual market prices billed.

~~No party~~ TURN proposed a transition cost allocation method that addresses cost causation in such a way as to directly link actual usage patterns and provide ~~actual generation costs or~~ an appropriate proxy for actual generation costs. We believe such a methodology must be considered and analyzed for these purposes because it is the only proposal in the record which addresses cost causation in a way related to demands placed on the system. ~~Once the data is available and can be scrutinized by the parties and the Commission, we may find that this method is appropriate to use directly to allocate costs. Or, we may find that the bill impacts or other equity concerns~~

~~associated with a change form the 1996 methodology to a cost causation methodology require certain modifications, such as caps or phase-ins. In any case, our preference is to obtain the necessary data to allow us to consider a cost causation-based methodology along with the other proposals on the record in this case.~~

Exhibit 91 is a comparison exhibit in which the three allocation methodologies [29] are analyzed to determine what percentage of transition costs should be allocated to each class. This Exhibit shows that the allocation would change by about 10% or less for each class (compared with EPMC) using the top 100 hours method proposed by TURN. In comparison, the SAPC method would change allocations less than 10% in most cases, and the equal cents methodology would change allocations more than 10% in many cases.

Based on this data, we can conclude that the TURN methodology for allocating costs based on the top 100 demand hours would meet our obligations under §367(e)(1)(2) and (3). This methodology is different from the method in place today, but to adopt it would be an exercise of our continuing cost allocation authority. The top 100 hours methodology would not result in price increases for customers as compared to 1996 rates, because overall rates will have decreased substantially at the end of each utility's rate freeze.[30] Finally, the changes of 10%

[29] SAPC, equal costs and top 100 hours, all as compared to EPMC.

[30] Using SDG&E as an example, transition costs during the rate freeze period averaged 20% of overall revenues. Ongoing transition costs are expected to average about 20% of pre rate freeze transition cost levels in 2000. Because of the reduction in transition costs (and other factors), rates dropped about 15% on average due to the end of the rate freeze. For a class with 20% of the responsibility for transition classes in 1996, a 10% increase in responsibility would lead to a 22% allocation post rate freeze. But 22% of 20% of previous transition costs is still only 4.4% of rates, which is far less than the 20%

Footnote continued on next page

or less in allocation for each class maintain allocations which are substantially in the same proportion as the allocations on June 10, 1996.

However, while we can adopt the policy to use the top 100 hours methodology, we cannot adopt actual allocations consistent with it at this time. As is noted in Exhibit 91, TURN's methodology is converted to allocation percentages based on historical data from 1991-1993 which is neither confirmed nor supported by other parties. Therefore, we need to update the data to obtain actual allocations.

~~Because utilities have sold many of their generation plants, we can no longer gather data on generation marginal costs. We can, however, look for a proxy for generation marginal costs. At this time, the PX appears to be the best proxy for generation marginal costs. We recognize that PX prices are not exact analogs to generation costs. In many instances, PX prices may well be far above or below actual costs for one or all generators. However, at this time, the PX price is the best proxy available for the unregulated generation market costs. Further, even if prices do not match well with costs, the PX price most likely varies with hour, day, month and year in some reasonable relation to industry cost variances.~~

Therefore, we will order the utilities to file a joint ~~application~~ Advice Letter within 60 days of this decision which updates the top 100 hours methodology. Utilities should use the class average hourly load profile data used to calculate the PX credit (with a reasonable allocation to streetlighting and

of rates devoted to transition costs during the rate freeze. The net impact is that customers in the class receive a significant rate decrease from the end of the rate freeze, even if the allocation of ongoing transition costs is slightly higher than the allocation of transition costs during the rate freeze.

any other class without a calculable load profile). The data should be used to identify the top 100 demand hours for 1998 and 1999 and identify the percentage allocation attributable to each class. This percentage should be averaged over the two years, and ongoing transition costs should be allocated based on these averaged percentages by class. We note that the 1998 and 1999 data may or may not be representative of normal years. However, we believe updated data using load profiles will produce superior results to the data underlying the 1991-1993 calculation in Exhibit 91. We reserve the right to further update the data or otherwise change the ongoing transition cost allocations consistent with §367 in the future. ~~compares the day-ahead hourly PX prices for all hours of 1999 with the load patterns (including estimated load curves when appropriate) and usage levels of each customer class. The application should then show the cost responsibility for each class over the year of 1999 for each utility.[31] Next, the application should show the bill impacts for each customer class from changing from the 1996 EMPC method to a method based on the above analysis. Each utility may then propose whether this exact allocation should be used for transition costs after the transition period, some variation of this method, or some other methodology.~~

31 ~~A simple example: There are two classes. One class uses 75% of its power at 3 pm and 25% at 3 am. The other class uses 75% of its power at 3 am, and 25% at 3 pm. The 3 am PX price is 2 c/kwh and the 3 pm price is 4 c/kwh. The first class uses 1200 kwh and the second class uses 400 kwh. The cost responsibility for the first class is (900*.04)+(300*.02)=$42 and the cost responsibility for the second class is (300*.02)+(100*.04)=$10. Therefore, the first class should be allocated 81.8% of the costs (42/52) and the second class should be allocated 19.2% of the costs (10/52). Obviously, the actual analysis would be much more complex than this example.~~

Assuming the joint Advice Letter provides data consistent with this decision, ~~The allocation of transition costs will continue to be by the 1996 method until this new application is processed, or until the end of the transition period, whichever is later.~~ we will adopt the results as a proxy for TURN's top 100 hours proposal, with the caveat that we will need to review the results once again to ensure compatibility with §367(e) if there are significant allocation differences from those indicated in Exhibit 91 and to ensure that no individual customer would experience a rate increase from changes in transition cost allocation (as compared to rates during the rate freeze).

B. Allocation of Restructuring Implementation Costs

Restructuring implementation costs are costs resulting from the implementation of direct access, the PX, and the ISO. Treatment of these costs is addressed in Pub. Util. Code § 376[32]. We discussed the eligibility of such costs for § 376 treatment in D.99-05-031, D.99-09-064, and D.99-12-032. In D.99-06-058, we determined that these costs should be allocated using a SAPC methodology during the rate freeze. Again, the question before us now is whether the allocation methodology can and should be changed after the rate freeze.

As with ongoing transition costs, SCE, SDG&E, FEA, and Large Users propose to continue to use a SAPC method for restructuring implementation cost

[32] Section 376 states that the utilities may recover restructuring implementation costs found reasonable by the Commission, and, to the extent that such recovery reduces the opportunity to recover the uneconomic costs of generation during the rate freeze, the utility may recover the displaced uneconomic costs after December 31, 2001.

allocation. These parties believe that maintaining the SAPC methodology is most consistent with the cost-shifting principles of § 367(e)(1).

They point out that implementation costs are not recoverable after the rate freeze, only the displaced transition costs. Therefore, the displaced transition costs should have the same allocation as all transition costs. These parties maintain their position that like transition costs, costs displaced by recovery of restructuring implementation costs should be allocated using a SAPC methodology.

TURN, UCAN, and ORA argue that these costs should be allocated using equal cents-per-kilowatt hour methodology. These groups argue that allocating restructuring implementation costs using SAPC would spread the costs disproportionately to those classes that have not benefited equally from electric restructuring. These parties state that in D.99-06-058, the Commission mandated a continuation of the SAPC through the transition period due to cost-shifting considerations, but implied consideration of an alternative treatment of 376 costs at the end of rate freeze. PG&E proposes to attribute these costs to a function such as distribution and to allocate the costs in a similar manner to others in the particular function.

~~As discussed in the previous section, we have determined that once the rate freeze ends, the Commission has full authority over cost allocation and that the cost-shifting principles of § 367 expire once the rate freeze ends.~~ The restructuring implementation costs themselves are not recoverable after the rate freeze. Pursuant to § 376, the only costs recoverable are the transition costs that were displaced because of recovery of restructuring implementation costs. These costs should not be singled out from other transition costs for separate treatment, but instead should be allocated according to the same methodology as other ongoing transition costs. Therefore, transition costs displaced because of recovery of restructuring implementation costs should be allocated using a ~~cents-per-kilowatt-hour~~ top 100 hours methodology applied on a system-wide basis.

C. Nuclear Decommissioning and Public Purpose Costs

UCAN and TURN argue that nuclear decommissioning costs should be allocated based on equal cents per kilowatt-hour. These costs are currently allocated using an EPMC methodology. They argue that nuclear costs were incurred to meet base as opposed to peak demand and that costs should be borne by those consuming larger volumes of power.

Large Users and FEA argue that decommissioning costs are the costs of doing business for a utility with nuclear plants and are not a function of energy demand or how many kWh are produced. They argue that these costs have traditionally been recovered residually on a SAPC basis (D.97-08-056, p. 36). FEA points out that decommissioning is a result of the very existence of the plants and not the amount of power produced.

Edison maintains that TURN and UCAN provide no justification to change the allocation of nuclear decommissioning costs. PG&E also opposes this proposal. PG&E contends that neither nuclear decommissioning costs nor public purpose costs are rate components that are associated with ending the rat freeze; therefore, PG&E contends that proper discussion of these components should take place in A.99-03-014, its Phase 2 general rate case (GRC) proceeding.

TURN and UCAN propose to continue the current cents-per-kilowatt-hour cost allocation for costs related to the CARE program. They recommend that, until decisions are made on how energy efficiency public purpose programs will be funded and administered after 2001, the current SAPC cost allocation methodology for non-CARE costs continue and be tracked in a one-way balancing account. When a final determination regarding funding for public purpose programs is made, allocation of the funds should be decided at that time.

ORA recommends that we direct the utilities to propose a consistent format and process for separately tracking, reporting, and reconciling all public purpose revenues in the 2000 Annual Earnings Assessment Proceeding (AEAP). Edison believes the ATCP is appropriate place to assess these programs. PG&E agrees that a balancing account must be created to track the difference between the revenues collected under the public purpose rate component and the authorized public purpose revenue requirement and proposes the Public Purpose Program Revenue Adjustment Mechanism (PPPRAM), a two-way balancing account. PG&E contends that a discussion of public purpose cost allocation should take place in its Phase 2 GRC proceeding.

We previously considered nuclear decommissioning cost allocation in D.97-08-056, in which the Commission was constrained by the cost shifting provisions of AB 1890. That decision states:

> We direct the utilities to allocate these program costs using PG&E's system average percent method, which is closest to the current cost allocation methods and therefore accommodates AB 1890's rate freeze and prohibition against cost-shifting (*Id.*, mimeo. at p. 36).[33]

In this decision we have established that cost shifting is not prohibited once the rate freeze is terminated. In addition, we have stated our intent to further our policy of unbundling rates and functionalizing costs. Consistent with our approach to transition cost allocation, nuclear decommissioning costs should

[33] We note that although PG&E's and the Large Consumer's SAPC proposal was adopted in D.97-08-056, SCE's and SDG&E supported the cents per kilowatt hour methodology, the proposal the TURN and UCAN now support.

be assigned to function. We agree with TURN's and UCAN's argument that nuclear decommissioning costs are most appropriately assigned to the generation function. Therefore, we will adopt a cost allocation methodology based on energy consumption. Once the rate freeze ends, nuclear decommissioning costs shall be allocated using a cents-per-kilowatt-hour methodology. This approach is not only consistent with our treatment of transition costs, but is also the most equitable allocation methodology given the cost saving disparity between large and small customers.

CARE costs should continue to be allocated on a cents-per-kilowatt-hour basis. For energy efficiency public purpose programs, we agree that it is reasonable to continue SAPC cost allocation after the rate freeze. We acknowledge that a new mechanism must be established to ensure that the UDCs collect the authorized revenue requirement for public purpose programs. We approved the Public Purpose Programs Adjustment Mechanism (PPPRAM) and Edison's PPPRAM in D.99-10-057 on an interim basis. We affirm that approval here and establish that these accounts should be two-way balancing accounts. Further issues regarding funding and tracking of funds for the period after 2001 should be determined in the public purpose rulemaking, R.98-07-037. We will not make any recommendations here as to what issues should be considered in the 2000 AEAP.

D. Reliability Must Run Cost Allocation

Reliability Must Run (RMR) contracts ensure the ISO's ability to summon generators to provide reliability and system stability when the market fails to provide the necessary support. The RMR contracts are subject to FERC jurisdiction. During the rate freeze period RMR costs are being recovered through the Commission-established Transition Revenue Account (TRA).

Recovery and allocation of RMR costs through the TRA during the rate freeze is being reviewed in the Revenue Adjustment Proceeding (A.99-08-022 *et al.*). Once the rate freeze terminates the utilities will no longer have the TRA cost recovery mechanism and must seek authorization at the FERC to recover RMR costs[34].

Several parties, including TURN, FEA, SCE, and PG&E, address RMR costs in this proceeding. The Phase 1 decision explicitly stated that FERC has jurisdiction of RMR costs and defers to the FERC on all related matters (D.99-10-057, mimeo. at pp. 29-30, Finding of Fact 9, Conclusion of Law 11). Since this matter was fully litigated in Phase I of this proceeding we will not readdress the issue of post-transition treatment of RMR costs here.

E. Inclusion of Non-CTC Costs on the Ongoing CTC Rate Component

The utilities may continue to offer interruptible or curtailable service until March 31, 2002 pursuant to § 743.1. TURN and ORA object to PG&E's and Edison's proposal to include any discount costs and rate limiter adjustments in the ongoing CTC component on the customer bill. Edison and PG&E argue that the cost separation proceeding assigned these costs to the generation function. While the utilities concede that these costs are not transition costs as defined in § 367, the ongoing CTC component is the only remaining generation related component. ORA and TURN argue that inclusion of non-CTC costs should be rejected because it will be a misrepresentation of the costs in that component and is not easily explained as related to a particular utility function or activity. ORA and TURN further argue that the CTC component was created for the specific

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[34] SDG&E has completed its transition period and FERC has approved a post-transition RMR recovery mechanism for SDG&E, San Diego Gas & Electric Co., 88 FERC 61,017 (1999).

purpose of collecting transition costs as defined in § 367 and the costs stemming from interruptible programs and discounted rates are not transition costs. ORA suggests that these costs are more appropriately assigned to the distribution function. TURN does not specify which function the costs should be assigned to, but states that consistent with Commission policy of disclosing the source of utility costs, the utilities could add a line item on the customer bill for these costs.

We agree with TURN and ORA that including such non-transition costs in the CTC component is improper and unlawful and misrepresents the costs in that component since it was created specifically for the collection of transition costs. ~~Since~~ Although D.97-08-056 designated these costs as generation-related, we ~~dis~~agree with ORA that they are more appropriately assigned to distribution function. Including the costs of interruptible discounts and rate limiter adjustments as a separate line item on the customer bill is administratively burdensome, although technically more correct. Since these costs are relatively short-lived, we will require this item to be assigned to the distribution function. We will not allow additional costs that are not transition costs to be collected in the CTC rate component.

ORA & PG&E agree that the power factor adjustment should be recovered through the distribution rate component.

~~While we are sympathetic to TURN's argument that a separate line item should be included on each customer's bill, we believe the cost effectiveness of this option was not explored on the record.[35] Significant expense and modification of UDC billing systems could be triggered by such a requirement. Yet this discount will expire in less than two years. We are loath to place such a~~

[35] TURN's suggestion was made in its reply comments

~~burden on the UDCs and their ratepayers without a showing that the costs incurred are outweighed by the consumer benefits to be achieved. We are also concerned that another new item on all customers' bills could lead to customer confusion necessitating a consumer education effort, again adding to the expense of this short-lived option. By the time we could remand this issue for a record and a decision, it may be too late to implement acceptance of TURN's suggestion. Therefore, we reject creation of a new line item on customer bills.~~

F. Rate Group Transition Cost Memorandum Account

The Rate Group Transition Cost Memorandum Account (RGTCOMA) tracks transition costs obligations and payments by rate group. The first issue to be resolved concerning this account is whether during the rate freeze the transition cost allocators should be adjusted for energy use profiles among classes. FEA, SCE, and Large Users propose to adjust the allocators for changes in class energy use profiles. These parties state that class allocators must be adjusted for changes in energy usage pursuant to § 371(a). ORA opposes that approach stating that § 367(e) mandates that the allocators remain fixed as they were on June 10, 1996, notwithstanding changes in energy usage patterns.

The second issue involves post rate freeze reconciliation of RGTCOMA balances. ORA recommends reconciling the difference between rate group CTC obligations and CTC revenues received. That is, CTC will continue to be collected after the rate freeze for rate groups that have a remaining obligation determined by the RGTCOMA balance.

SCE, PG&E, and the Large Users argue that such a reconciliation of RGTCOMA balances after the rare freeze is unlawful as determined in D.99-10-057. In that decision, we determined that any carry over of costs into the post rate freeze period is unlawful pursuant to §§ 368(a) and 367(a) (*Id*., mimeo. at p. 36, Conclusions of Law 3 and 4.)

Section 371(a) states:

> Except as provided in Sections 372 and 374, the uneconomic costs provided in Sections 367, 368, and 376 shall be applied to each customers based on the amount of electricity purchased by the customer from an electrical corporation or alternative supplier of electricity, subject to changes in usage occurring in the normal course of business.

Section 371(b) states:

> Changes in the usage occurring in the normal course of business are those resulting from changes in business cycles, termination of operations, departure from the utility service territory…..

We have explained that, during the rate freeze, § 367(e)(1) requires that transition cost be allocated in substantially the same proportion as similar costs were allocated in June of 1996. However, we do not believe that the language "in substantially the same proportion" is necessarily in conflict with the § 371(a) provisions mandating that transition cost allocation reflect changes in usage profiles. We agree with FEA, Large Users, and SCE that the statute mandates that the allocation of transition costs be adjusted for changes in usage patterns. Therefore, during the rate freeze, while transition costs continue to be allocated using an EPMC or SAPC methodology, allocators shall be updated to reflect changes in class usage profiles occurring in the normal course of business.

Regarding reconciliation of RGTCOMA balances, D.99-10-057 is explicit that costs cannot be carried over after the rate freeze period. In that decision, we also established refund accounts and mandated that over-collections must be returned to ratepayers using the allocation method used in the collection of those costs. (*Id.*, mimeo. at p. 16). In addition, it established that the rate freeze will end at the same time for all customers.

We reiterate that the rate freeze should end for all customers at the same time notwithstanding the class transition cost obligations in the RGTCOMA. Rate groups that have not met their transition cost obligation cannot continue to pay CTC post rate freeze as it would constitute a carry over of costs to the post rate freeze period. Such a carryover is unlawful pursuant to §§ 367(a) and 368(a).

D.99-10-057 provides for the difference between the amount of CTC authorized and the actual amount collected to be returned to ratepayers at the utilities authorized rate of return. The utilities shall propose a method to return the funds in the first ATCP following the end of the rate freeze.

V. Rate Reduction Bond Issues

Pursuant to § 841 *et seq.* and D.97-09-057 (Financing Order) SDG&E issued $658 million in rate reduction bonds in December of 1997 in order to finance a 10% rate reduction for eligible customers over the anticipated four-and-a-half year rate freeze period. According to the terms outlined in the Financing Order, the bonds will be fully repaid by 2007 and a charge to repay the bonds appears on the customer bill until that time. The Financing Order also required SDG&E to establish a Rate Reduction Bond Memorandum Account (RRBMA). When SDG&E ended its rate freeze early on July 1, 1999, the mandated 10% rate reduction for residential and small commercial customers also ended, leaving these ratepayers with unrealized savings. The Financing Order requires that any excess RRB proceeds be returned to ratepayers. SDG&E states that currently there is $423 million in excess RRB proceeds.

In this proceeding, SDG&E has made two proposals concerning the unrealized savings. The first is to return the money to ratepayers at the interest rate of 9.52% (reduced pre-tax rate of return on transition cost assets) rather than the 12.6% (SDG&E's authorized pre-tax rate of return) mandated by the Financing Order.[36] The second proposal is to return the money to customers over a shorter period than the life of the bonds.

SDG&E argues that the bonds were issued under the assumption that the rate freeze would last until March 31, 2002. In essence, SDG&E contends that imposing a 12.6% rate of return on excess bond proceeds penalizes SDG&E shareholders for their efforts in ending the rate freeze early. Further, SDG&E argues that pursuant to newly-enacted § 846.2 (Senate Bill (SB) 418 Stats. 1999, Ch. 683), this Commission has the discretion to change the interest rate by deeming it "fair and reasonable." SDG&E maintains that residential and small commercial customers are better off under this proposal. The Financing Order assumed that benefits to ratepayers equaled $126 million in net present value (NPV). Under this proposal, SDG&E states that customers will receive $298 million in NPV benefits. At the time the Financing Order was issued, no party contemplated that the rate freeze would end early; therefore, SDG&E maintains that it was reasonable to assign a higher interest rate to the surplus proceeds. However, SDG&E now contends that it is inequitable to impose this requirement.

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[36] SDG&E has also filed a petition to modify the Financing Order. ALJ Minkin asked SDG&E to specify which proceeding should address each issue. SDG&E indicated that the interest rate issue should be addressed in the decision regarding the petition to modify, but proceeded to brief the topic here. We will also address this issue in our decision regarding the petition to modify the Financing Order.

If the Commission does not alter the interest rate, SDG&E wishes to amortize the funds more quickly, e.g., over a nine-month period. However, if the interest rate is reduced, SDG&E will amortize the funds over a two-year period. SDG&E contends that this would synchronize the use of the remaining RRB funds with the originally intended term and use. SDG&E argues that the second proposal provides ratepayers with the highest net present value of all the proposals on the table

TURN, UCAN, Edison, FEA, and ORA object to both of SDG&E's proposals and argue that excess RRB proceeds should be refunded to ratepayers at SDG&E's authorized pre-tax rate of return throughout the life of the bonds. TURN, ORA, and UCAN argue that SDG&E was not required to issue bonds to fund the 10% rate reduction, but it chose to do so. They also argue that SDG&E was not required to take the riskier approach of issuing all the bonds at once, but rather could have issued them when necessary as the rate freeze progressed. Finally, TURN and UCAN state that the Financing Order was explicit regarding the terms and conditions of the bonds, including the risk if too many bonds were issued. SDG&E understood the risks fully. Parties argue that not only were the conditions completely understood, but the Legislature gave the UDCs veto power over the terms of the financing order in § 841(b):

> A financing order…shall become effective in accordance with its terms only after the electrical corporation files with the commission the electrical corporation's written consent to all terms and conditions of the financing order.

ORA, TURN, and UCAN argue that SDG&E had full discretion to use the bond revenue in any manner it chose to. The only issue of importance is that SDG&E understood the risks of over issuance of the bonds and accepted those terms. It had the opportunity to mitigate that risk and chose not to do it. SDG&E should comply with the terms that it agreed to.

UCAN refutes SDG&E's argument that it could not have known that the rate freeze would end early and that its fossil plants would sell higher than book value. UCAN maintains that SDG&E either ignored the impact of the generation sale on the length of the rate freeze or assumed a market value of zero. SDG&E states in response to UCAN's data request that "the estimated market value of the generating assets played no role either directly or indirectly in the revenue reduction bond calculations." (Ex. 82.) TURN and UCAN argue that if SDG&E had made reasonable estimates of generation asset values, it would likely have issued fewer rate reduction bonds.

TURN, UCAN, FEA, and ORA oppose the shorter amortization of the bond refunds because they contend that this approach would enable the UDC to skirt its interest obligations under the Financing Order. More importantly a shorter amortization period would be inequitable to future ratepayers that will continue to pay for the costs of the bonds but will not receive an offsetting credit. Current ratepayers would receive a windfall profit in the present but would continue to pay for the bonds. New SDG&E customers would be paying the bond cost without the offsetting credit.

Edison argues that SDG&E's proposal is unlawful. However, SDG&E contends that since SB 418 became law, this Commission has the discretion to alter the Financing Order. SDG&E argues that the opposing parties' position does not meet the "fair and reasonable" provision of Section 846.2, because it is not "fair" to shareholders.

We agree with UCAN, TURN, ORA, SCE, and FEA that the unrealized savings resulting from the excess RRB proceeds must be refunded to ratepayers at SDG&E's authorized pre-tax rate of return throughout the life of the bonds.

The Financing Order reads:

> Balances that are to be credited to rate payers in respect of issuance of rate reduction bonds that subsequently were determined not to be necessary in order to finance a 10% rate reduction for rates in effect on June 10, 1996 should bear interest at SDG&E's authorized rate of return (D.97-09-057, Conclusion of Law 33, Ordering Paragraph 19).

SDG&E does not deny that it issued all the bonds in a lump sum, a riskier approach than issuing them as the rate freeze progressed. SDG&E does not deny that it understood and agreed to the terms and stated risks embodied in the Financing Order. It simply says that issuing the amount of bonds that it did seemed reasonable at the time and that its shareholders should not be held responsible for decisions that were made and the terms agreed upon. We see no reason why SDG&E should not be held to the same level of accountability for its business decisions as any other entity that enters into an agreement.

SDG&E states that § 846.2 gives the Commission discretion to alter the interest rate provisions of the Financing Order to make it fair and reasonable to shareholders. Section 846.2 states:

> Notwithstanding subdivision (c) of Section 841, for any electrical corporation that ended its rate freeze period described in subsection (a) of Section 368 prior to July 1, 1999, the Commission may order a fair and reasonable credit to ratepayers of any excess rate reduction bond proceeds.
>
> "Excess rate reduction bond proceeds," as used in this section, means proceeds from the sale of rate reduction bonds authorized by commission financing orders issued pursuant to this article that are subsequently determined by the commission to be in excess of the amounts necessary to provide the 10 percent rate reduction during the period when the rates were frozen pursuant to subdivision (a) of Section 368.

SB 418 clarifies that the Commission has the authority to address the issues raised by SDG&E and order an alternative disposition of the excess bond proceeds, if appropriate. However, SB 418 does not require the Commission to accept SDG&E's preferred solution. We cannot agree that SDG&E's proposal for a reduced interest rate, which would result in reduced refunds to ratepayers, is fair or reasonable. SDG&E accepted the terms and conditions of the Financing Order, which provided that ratepayers would receive a specific return if the utility issued an unnecessary amount of bonds. To change the terms of that agreement is not reasonable or fair to the ratepayers that provided SDG&E with $658 million in bond revenues at the beginning of the transition period. Certainly, SDG&E enjoyed the benefits provided by the lump-sum issuance of the bonds.

We do not agree with protesting parties that a shorter amortization period is unnecessary. On the contrary, we believe it is appropriate to give customers their money back as soon as possible. Therefore, we will order SDG&E to file an Advice Letter with a plan to place a credit for the appropriate amount to reflect the unrealized savings resulting from excess rate reduction bond proceeds on applicable customer's bills in the next feasible billing cycle and/or to send a check for this amount to those customers. This is a fair and reasonable outcome of this matter, in compliance with § 846.2, because ratepayers will receive a credit of overpayments as soon as possible and therefore reach finality at the earliest possible date. Further, we note that a one-time refund or credit will minimize the impact on competitive energy service providers and demand responsiveness. We recognize that this will result in certain future customers paying bond costs without the benefit of the offsetting credit. However, AB 1890 recognized that bond costs would be paid by certain future customers well after the benefits from rate reduction bonds were realized. To the extent that this specific outcome is inequitable to future ratepayers, we defer to the overall wisdom of the Legislature in balancing the overall benefits and costs of restructuring.

VI. Other Ratemaking Issues

A. Recovery of Purchased Electric Commodity Account (PECA) Costs

D.99-10-057 adopted a PECA for SCE, SDG&E, and PG&E to track their purchased energy costs. PECA results in an energy rate that is designed to balance procurement costs and revenues in a given month. However, D.99-10-057 stated that we would address in Phase 2 whether dollar-for-dollar recovery of such costs is appropriate as well as related ratemaking issues resulting from our decisions on UDC procurement practices. We also clarified that the purpose of the PECA account was to track the costs of purchased electricity, not the costs of operating power plants.

Although the Commission adopted a PECA account for Edison in D.99-10-057, Edison recommends in its brief that the Commission not address post-transition pricing of energy procurement services in this proceeding or in the 1999 RAP. Instead, Edison recommends that this issue be addressed in its rate design proceeding. PG&E proposes specific ratemaking mechanisms for procurement costs that can accommodate adoption of rate capping, procurement incentive mechanisms, both, or neither. SDG&E also proposes a PECA account, like PG&E, but notes that the accounts are not identical in their set up because of different sub-accounts.

As proposed by PG&E, a monthly PECA rate would be set to recover the expected costs of providing procurement service and amortize any prior month under- or over-collection. The amortization component would be set monthly. Any under- or over-collection would earn interest at the short-term commercial paper rate. If the Commission adopts PG&E's proposed procurement incentive mechanism, the incentive or penalty would be recorded in the PECA and be either returned to or recovered from ratepayers over one year. If the Commission adopts PG&E's proposed rate capping mechanism then PG&E would also implement a DPRA to allow recovery of deferred revenue at a later date. If the rate cap were triggered, the difference between actual costs and collected revenues would be debited to the DPRA and recovered the next month (subject to the rate cap). In that month, the total procurement rate would be the sum of the PECA rate and the DPRA rate.

Weil notes that the utilities did not submit proposed tariffs to implement PECA in this proceeding. Weil takes issue with the fact that PG&E does not include a forecast of procurement costs in setting the PECA rate but instead charges a PECA rate based on the past month's costs. Weil argues that the monthly commodity rate should include a forecast element, an amortization element based on the difference between forecast and recorded costs, and an amortization element for PBR rewards / penalties, if adopted. In addition, Weil notes that the proper commodity rate needs to reflect a sales forecast for each month. Weil recommends the use of the prior month sales, adjusted to reflect long-term trends of month-to-month sales variations.

The CEC does not address the ratemaking aspects of PECA but instead focuses on the proper definition of procurement costs, for purposes of booking actual or recorded costs into the PECA account. The CEC argues that PECA should include not just the wholesale cost of energy, but also all of the supporting activities associated with procurement, plus overheads.

ARM argues that the Commission should make clear that the methodology developed in the 1999 RAP for calculating PX credits during the rate freeze will be the methodology used for calculating generation rates for the post-freeze period and will be applied immediately to SDG&E. Like the CEC, ARM believes that the proper generation rate includes much more than simply wholesale energy costs. New West and Commonwealth echo these positions.

The PECA account raises two primary issues: how to set the procurement rate, from an accounting and ratemaking standpoint, and what cost elements are properly included in the PECA rate. We address the second issue in the section "Interaction with Other Proceedings."

Regarding the accounting and ratemaking issues, we agree with Weil that PG&E's proposal does not contain enough detail for us to adopt it outright. In addition, we agree that the monthly PECA rate should be based on ~~forecast~~ procurement costs incurred to serve customers to whom the rate applies, including a forecast of any procurement costs for which the utility has not received a final bill when the rate is developed for the given month, an amortization component to account for prior month over- or under-collections, and a trended sales forecast. The amortization component will allow for true up between actual and recorded costs and revenues. Revenues should be recorded to PECA less ~~net of~~ franchise fees and uncollectibles and under- or over-collections should earn interest at the short-term commercial paper rate as proposed by PG&E. Because we do not adopt a procurement PBR or rate capping, we need not include the other elements of PECA as proposed by PG&E.

As required by D.99-10-057, SDG&E was ordered to file an advice letter with tariff modifications that implemented the provisions of that decision. Similarly, PG&E and Edison were ordered to file advice letters three months prior to the earliest forecasted date that the rate freeze will end or September 2001 if the rate freeze does not end early. The advice letter is to propose tariff modifications and provide calculations of proposed post rate freeze rates. Therefore, each utility has been ordered to implement the PECA at the appropriate time. SDG&E, PG&E, and Edison shall incorporate the findings of this decision and the 1999 RAP decision in implementing the PECA accounts. Within ten days of the effective date of this decision, SDG&E shall update any tariffs necessary to be modified as a result of this decision.

B. Load Retention Discounts

In this proceeding, SDG&E requests a two-year extension of its load retention discount, Schedule 4.D, which was to expire on December 31, 1999. SDG&E also filed a Petition for Modification of D.96-06-033 in its Rate Design Window proceeding (A.91-11-024) on October 5, 1999 to extent the discount for two years. SDG&E argues that no party has opposed the extension in this proceeding.

UCAN and ARM contend that this issue has not received enough consideration in this proceeding and should be fully litigated in the SDG&E's Rate Design Window proceeding. They argue that market structure and competition issues should be considered before extending the discount.

Consistent with our stated policy in this proceeding, until the Commission more fully addresses the role of the UDC and underlying market structure issues, we prefer that the utilities not implement or extend rates or discounts that could be competitive. In our view, this is a "plain vanilla" approach, which, of course, may be modified as a result of our staff study and further considerations of key market structure issues.

However, we recognize that we have taken actions in other decisions that impact this finding. In addition, the Legislature has required that certain rate schedules and optional service be offered. For example, § 743.1(b) requires that optional interruptible or curtailable service continue at least until March 31, 2002 and that the level of the pricing incentive shall not be altered from the levels in effect on June 10, 1996 until March 31, 2002. This section also states that this

Commission is to direct the utilities to continue efforts to reduce rates charged to industrial customers without shifting cost recovery to other customer classes.

We extended SDG&E's ability to offer load retention discounts in D.00-01-007, in which we stated that load retention discounts would be extended until a determination was made in either this proceeding or A.91-11-024, which ever came first. We also stated that "ARM's position should be raised in the hearing process where the issue can be joined in the context of a full record." (*Id.*, mimeo. at p. 2.) A full record has not been developed on this issue; therefore, this issue should be more fully considered in A.91-11-024.

Similarly, in D.99-09-065, we extended Edison's self-generation deferral rate, expansion, attraction and retention economic development rates, environmental pricing credit and the agricultural bypass deferral rate until March 31, 2000. If Edison does not request any extension of these flexible pricing options in its post-rate freeze rate design application (A.00-01-009), their availability to new customers will sunset on that date. We also stated that the incremental sales rate, spot-pricing amendment and real-time pricing rate schedules must be extended until the end of the rate freeze. We recognized that parties may propose modifying or closing such schedules and that this record should be developed in A.00-01-009.

Therefore, while we prefer that the utilities not implement or extend rates or discounts that could be competitive, we cannot fully implement such objectives at this time. Instead, a full record should be developed for our consideration in both A.91-11-024 and A.00-01-009 for SDG&E and Edison, respectively. For PG&E, we expect that issues related to load retention and special rates will be brought forward for our consideration in A.99-03-014.

C. Use of Hourly Interval Meters

When rates are frozen, customers have little incentive to adjust energy usage patterns and remain unmotivated to shift consumption to the low demand times when energy prices are lowest. This is because under the rate freeze customers will pay the same price for energy whether they consume during peak hours when prices are higher due to high demand, or if they consume in the off peak hours when prices are lowest. In addition, since customers are charged for the average energy cost, those customers with better than average load profiles in effect subsidize those that have worse than average load profiles. A fundamental objective of electric restructuring has been to increase the customer's ability to respond to market signals, which will foster greater market efficiency, the expectation being that greater efficiencies would serve to prompt lower overall market prices. Several parties in this proceeding propose to change the current averaging methodology to increase customer response to market signals, allowing for greater efficiency in meeting energy demand.

ORA and CEC contend that, once the rate freeze ends, the hourly PX prices should be passed through to those customers with interval meters. ORA and CEC argue that allowing customers to experience PX price variations will foster the Commission's objective of increasing responsiveness to price signals and increasing market efficiency by providing an incentive for customer to shift load to non-peak periods.

PG&E originally opposed ORA's and CEC's proposal, but conceded in its brief that customers with hourly meters should be billed using hourly data. PG&E agrees with ORA's proposal with three qualifications: the hourly meter must be of revenue quality; the proposed treatment should not be discriminatory; and customers that have hourly meters at the time the transition period ends should be given the one time opportunity to elect to remain with class average profiling.

TURN and UCAN express concern that the use of advanced meters could distort the load profile for those customers that continue having energy prices averaged among the class. The CEC believes that if the use of accurate meters results in inequities for some customers, the approach should be to correct the inequities, not ignore the more accurate meters.

We will adopt the ORA and CEC proposal that all customers with hourly interval meters be billed using hourly data once the rate freeze ends. This approach is consistent with our long-established policy of increasing customer price responsiveness, advancing market efficiency, and prompting lower energy prices[37]. We will not approve PG&E's proposal to allow customers with interval meters a one-time opportunity to remain on averaged prices once the transition period ends. Such an approach would be inconsistent with the objective of removing intra-class subsidies by having customers charged for the power they actually consume and would undermine our goal of increasing customer response to price signals.

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[37] The Commission has stated its support for demand responsiveness programs and the ability to directly respond to changes in energy prices. The Preferred Policy Decision (D.95-12-063) recognized the importance of real-time meters and that corresponding real-time prices could serve to encourage customers to switch their energy use to off-peak periods. The Commission's support for demand responsiveness programs have been reiterated in D.97-08-056 and D.97-10-087. In addition, Resolutions E-3619, E-3624, and E-3624, authorize demand responsiveness programs and reinforce the Commission's policy objective of increasing customers price responsiveness.

VII. Interaction with Other Proceedings

Several parties, e.g., WPTF, ARM, Commonwealth, New Energy, and CEC, request that the Commission, in this proceeding, affirm that PX credit issues will definitively be resolved in the 1999 RAP, A.99-08-022 *et al.* Specifically, these parties argue that UDCs have an unfair advantage in competing with ESPs because the PX price is passed through to bundled customers at the wholesale level, while ESPs must charge retail prices to cover their costs. In other words, the competitors state that the UDCs' costs of procuring energy (overhead, scheduling, bidding, etc.) are subsidized by distribution rates, while the ESPs have no such subsidy. They want the Commission to strongly convey that it intends to remedy the situation in the 1999 RAP. WPTF also recommends that the Commission take no position in this proceeding regarding default rates that would later bind the options of the Commission in determining the default provider issue.

The CEC advocates that this decision "should clarify that PECA is the basis for the frozen rate energy charge on all customer bills for SCE and PG&E during the balance of the rate freeze period for these two utilities, as well as the basis for default energy procurement service following the termination of the rate freeze for any UDC." (CEC brief, p. 30.) ARM argues that the Commission should make clear that the methodology developed in the 1999 RAP for calculating PX credits during the rate freeze will be the methodology used for calculating generation rates for the post-freeze period and will be applied immediately to SDG&E.

PG&E, SCE , SDG&E, and Farm Bureau argue that a Scoping Memo in the 1999 RAP was issued on October 19, 1999, stating the issues to be reviewed in that proceeding. Since that ruling recognizes that PX credit issues are designated for the RAP, no further statement here is necessary. The issues are squarely before us in A.99-08-022 *et al.*

In this decision we adopt a PECA to record procurement costs and revenues in order to set the procurement rate. In the post rate freeze era, PECA effectively replaces the PX credit approach as the way of setting energy rates. We agree that all elements adopted as part of the PX credit during the rate freeze should also be reflected in the post-rate freeze procurement rate. The costs booked to PECA and the resultant rate should reflect all costs adopted as part of the PX credit in the 1999 RAP for each utility. SDG&E should adjust its PECA tariffs accordingly.

SDG&E and UCAN also point out that there is an overlap in the RAP and this proceeding in relation to the Rate Reduction Bond Memorandum Account. SDG&E argues that an audit of the balances in that account may be reviewed in the RAP. We agree and find that this audit should occur in SDG&E's next RAP. We direct Energy Division to conduct an audit of SDG&E's Rate Reduction Bond Memorandum Account and associated savings to ratepayers. We leave it to the assigned Commissioner and ALJ to set the schedule for this audit report.

ORA agrees with Edison's proposal to maintain both the RAP and the ATCP post rate freeze. The modified RAP would be a forecast proceeding and would include the justification for various revenue requirement forecasts and consolidation for various costs and payments. The ATCP would be a reasonableness proceeding, which would review transition cost recovery for ongoing transition costs. PG&E would rather consolidate those two proceeding and call it the Annual Electric Ratesetting Proceeding (AERP), with both a forecast and reasonableness phase.

The RAP was first discussed in D.96-12-077 and D.96-12-088. It was established to compare each utility's authorized revenue requirement with actual recorded revenues and to update authorized revenues for PBR and other proceedings. By Coordinating Commissioner's Ruling issued March 14, 1998 in R.94-04-031 and the Scoping Memo issued in A.98-07-006, the RAP has evolved into a consideration of revenue allocation and rate design during the rate freeze, the accuracy of the PX credit, and other accounting issues, such as the elimination or modification of balancing accounts and memorandum accounts. The ATCP was established in D.97-06-060 and D.97-11-074 to review recorded TCBA entries and to review accelerated amortization of uneconomic generation assets. The purpose of this proceeding is to review transition-cost related costs and revenues and to determine if all entries are justified.

On both procedural and substantive grounds, we agree with Edison and ORA's proposal to retain separate proceedings. The modified RAP will address forecast issues, as necessary and the modified ATCP will address reasonableness issues, including a review of procurement costs to the extent costs above the wholesale PX rate are included in the PECA. The issues are likely to be different, with different procedural tracks. Because the Commission is encouraged to close ratesetting proceedings within 18 months (SB 960, Stats. 1996 Ch.856), it is reasonable to ensure that the issues addressed in these proceedings are discrete. ORA appears to agree with Edison that the modified ATCP should include the review of the operation of various balancing and memorandum accounts, such as accounts associated with PBR exclusions, nuclear decommissioning, and public purpose programs. Edison has clarified that this review should include a review of the reasonableness, status, and compliance with Commission decisions or legislation. It may be reasonable to consolidate the RAP and ATCP proceedings after the rate freeze, but we need a better sense of what each of these proceedings will accomplish at that time.

Finally, as we have stated previously, D.99-10-065 designated a timeframe for deciding the default provider issue.

Findings of Fact

1. It is premature to adopt a procurement PBR mechanism at this time because the new market structures are not sufficiently developed and because the Commission has not made determinations as to the role of the UDC in supplying default customers.

2. ~~We are not convinced that UDCs could purchase electricity at prices that are consistently lower than the PX price, outside of the CalPX market~~. ~~Thus,~~ W~~w~~e are not convinced that a procurement PBR mechanism avoids perverse incentives or properly aligns the UDCs' interests with customers' interests.

3. We do not intend to implement mechanisms that may have the perverse incentive of encouraging the UDC to retain customers by using unfair practices; e.g., using resources of the monopoly distribution company to retain customers for the procurement function.

4. With properly-designed incentive regulation, once the benchmark is established, little regulatory oversight is required because the interests of shareholders and ratepayers are properly aligned. ~~That is not the case here.~~

5. While a number of parties with divergent interests support the partial SDG&E settlement, a wide range of interests also opposes the settlement.

6. The market is not sufficiently developed to support the proposed settlement and we do not intend to prejudge any action that this Commission or the Legislature might take with regard to default providers or the role of the UDC.

7. When SDG&E's gas procurement PBR was adopted in 1993, gas procurement competition was well developed and several robust, exogenous

benchmarks existed that parties agreed were reliable. In other words, gas basin competition was much more mature than the state of electric procurement competition is today.

8. Although the proposed settlement is characterized as an experiment, we are not convinced that this experiment will enable the Commission to determine its success when completed or that the experiment itself does not present unreasonable risks.

9. ~~We prefer~~ It is reasonable to require continued purchasing from the CalPX and related markets (including day-ahead, day-of, block forward, and the ISO imbalance energy markets) and to permit utilities to opt also to make purchases from any qualified exchange in order to better understand the impacts of the developing market after the rate freeze.

10. Once the market is more robust and ~~we have articulated~~ as we consider our approach to the default provider issue and the role of the UDC, it may be beneficial to adopt procurement incentives. ~~At that point~~ During that proceeding, we would recommend a collaborative approach with clearly articulated goals and objectives.

~~11.By continuing the mandatory buy requirement, we take steps to ensure that the market itself is more robust and competitive and resolve concerns regarding reasonableness reviews by deeming the wholesale PX price as reasonable.~~

~~12.~~11. The CalPX is no longer the only exchange where utility ~~these~~ transactions should occur. The CalPX's tariff is filed with FERC and its implementing protocols obligate the CalPX to develop a market-clearing price that clears all of the supply and demand bids submitted to it. ~~; i.e., it is obligated to find a market clearing price that best satisfies all qualified bids and is the direct result of a mathematical algorithm that solves these equations.~~ However, other qualified exchanges may now exist that can perform a similarly reliable function

12. The Commission should now let the mandatory buy requirement as to only the Cal PX expire because the justification for limiting purchases by UDCs to only the Cal PX has ended.

13. Adequate price transparency may exist outside the Cal PX.

14. The link of price transparency to mitigation of market power has weakened due to utility divestiture of generation.

15. Changes in the mandatory buy requirement should have no impact on our regulatory burden.

16. Opening up trading now to qualified exchanges will supercharge retail access and competition in generation and trading.

17. Market efficiency dictates an expansion of the mandatory buy requirement to other qualified exhanges.

18. Allowing use of qualified exchanges during the transition period will be a spur towards their more robust development by the end of the transition when the mandatory buy requirement expires completely.

19. The PPD currently permits use of exchange other than the Cal PX, as well as use of bilateral contracts, by entities other than UDCs.

~~13.~~20. Pre-approval of SDG&E's prescribed procurement guidelines at this time implies a sanction of reasonableness and tends to negate the concept of competition. Until we determine the role of the UDC in the post-transition period, we will not prescribe procurement practices other than to say qualified exchanges may now be utilized.

~~14.~~21. We reject PG&E's proposal that it is necessary to cap rates in order to protect residential and small commercial customers from potential price volatility and corresponding rate increases.

~~15.~~22. We did not initiate electric restructuring in order to shield consumers from the market. We agree with Weil and TURN that customers need accurate price signals in order to react and protect themselves against periodic price spikes.

~~16.~~23. Masking prices results in incomplete and inefficient market structure and system demand, and compromises system reliability. Only through accurate price signals can customers understand how their usage impacts the system and make economically efficient choices.

~~17.~~24. Until we determine the role of the UDC in the new market, it is premature to allow the UDC to offer new products and services, other than those already authorized by prior decisions,~~, which extend to a particular date, or by specific legislation.~~ or which are the subject of other proceedings before the Commission and are not limited or prohibited by this decision.

~~18.~~25. It is reasonable to allow the utilities to continue to offer balanced payment plans to their residential customers. Various programs are already in place to assist low-income customers with their energy bills; e.g., California Alternative Rates for Energy (CARE) provides a rate discount.

~~19.~~26. We will not expand the balanced payment plan program to streetlighting customers, because we prefer that the market develop a solution to this problem.

~~20.~~27. We will require that the UDCs continue to purchase power through the CalPX or any qualified exchange at least until the time when PG&E, Edison, and SDG&E have all ended the rate freeze. That is, the mandatory buy requirement will not end until the rate freeze has ended for all three of the utilities. It is expanded to permit purchases from any qualified exchange as defined herein. ~~which provides equal nondiscriminatory access and a mechanism for timely~~

~~price transparency.~~ Advice letter filings by the UDCs, separately or jointly, should determine whether an exchange is qualified.

~~21.~~28. The presence of large energy purchasers, such as the UDCs, attracts generators and ESPs to the market serving to increase liquidity and depth. The mandatory buy requirement provides a more level playing field that maintains ESP confidence in the market. As more qualified exchanges enter the market, more innovation and ingenuity in procurement practices will emerge.

~~22.~~29. So long as any utility continues to collect stranded costs, all the utilities must continue to buy from the CalPX or any qualified exchange. The total withdrawal of purchases from the Cal PX by any one utility can compromise the market price, thus serving to jeopardize the integrity of the competition transition charge for the utilities that remain under a rate freeze. All three utilities must continue to purchase power from the Cal PX or a mixture of the Cal PX and ~~or~~ any qualified exchange at least until the last utility has ceased collecting stranded costs.

~~23.~~30. Pursuant to D.99-10-057, three months prior to the anticipated date the rate freeze will end, or no later than September of 2001, PG&E and Edison must file advice letters informing the Commission and parties of the expected end of the rate freeze. These advice letter filings must include all necessary tariff language and preliminary statements using the four PX price forecast scenarios described in D.99-10-057.

~~24.~~31. In order to promote timely rate changes, we also required PG&E and Edison to file a supplement to this advice letter five days following the date upon which all the criteria for ending the rate freeze have been satisfied. The filing is to provide the actual rates to be implemented after the rate freeze and the ratemaking mechanisms authorized by D.99-10-057 and this order. Due to rate unbundling and the many ratemaking proceedings before the Commission, rates have and will continue to diverge from those in effect when rate were frozen on June 10, 1996. These advice letters will serve to notify parties and this Commission of the end of the rate freeze for PG&E and Edison.

~~25.~~32. At the end of the transition period, effective April 1, 2002, the mandatory buy requirement for UDCs should be eliminated.

~~26.~~33. A post-rate freeze continuation of allocating costs in a manner based on bundled rates is inconsistent with current ratemaking policies. It is inappropriate to continue the EPMC or SAPC methodology to allocate ongoing transition costs because those methodologies are derived from outdated bundled ratemaking methodologies.

~~27.~~34. Transition costs are most appropriately assigned to the generation function. Such a functionalization of costs is consistent with the Commission policy of rate unbundling and cost functionalization.

~~28.~~35. Neither the EPMC method nor the equal cents per kwh method of allocating transition costs fully take into account the way actual generation costs are incurred by class. The top 100 hours methodology appropriately allocates transition costs based on demand.

~~29.~~36. Restructuring implementation costs are costs resulting from the implementation of direct access, the PX, and the ISO. Treatment of these costs is addressed in Pub. Util. Code § 376.

~~30.~~37. In D.99-06-058, we determined that these costs should be allocated using a SAPC methodology during the rate freeze.

~~31.~~38. The restructuring implementation costs themselves are not recoverable after the rate freeze. Pursuant to § 376, the only costs recoverable are the transition costs that were displaced because of recovery of restructuring implementation costs. These costs should not be singled out from other transition costs for separate treatment, but instead should be allocated according to the same methodology as other ongoing transition costs. Therefore, transition costs displaced because of recovery of restructuring implementation costs should be allocated using the cents-per-kilowatt-hour methodology applied on a system-wide basis.

~~32.~~39. We previously considered nuclear decommissioning cost allocation in D.97-08-056, in which the Commission was constrained by the cost shifting provisions of AB 1890.

~~33.~~40. Consistent with our approach to transition cost allocation, nuclear decommissioning costs should be assigned to function. We agree with TURN's and UCAN's argument that nuclear decommissioning costs are most appropriately assigned to the generation function.

~~34.~~41. Once the rate freeze ends, nuclear decommissioning costs should be allocated using a cents-per-kilowatt-hour, usage-based methodology.

~~35.~~42. CARE costs should continue to be allocated on a cents-per-kilowatt-hour basis. For energy efficiency public purpose programs, we agree that it is reasonable to continue SAPC cost allocation after the rate freeze.

~~36.~~43. New mechanisms must be established to ensure that the UDCs collect the authorized revenue requirement for public purpose programs. We approved the PG&E's PPPRAM and Edison's Public Purpose Program Adjustment Mechanism in D.99-10-057 on an interim basis. We affirm that approval here and establish that these accounts should be two-way balancing accounts. Further issues regarding funding and tracking of funds for the period after 2001 should be determined in the public purpose rulemaking, R.98-07-037 or other proceedings, as appropriate.

~~37.~~44. Reliability Must Run (RMR) contracts ensure the ISO's ability to summon generators to provide reliability and system stability when the market fails to provide the necessary support. The RMR contracts are subject to FERC jurisdiction.

~~38.~~45. During the rate freeze period RMR costs are being recovered through the Commission established Transition Revenue Account (TRA). Once the rate freeze terminates the utilities will no longer have the TRA cost recovery mechanism and must seek authorization at the FERC to recover RMR costs

~~39.~~46. D.99-10-057 explicitly stated that FERC has jurisdiction of RMR costs. and defers to the FERC on all related matters. We will not relitigate these matters.

~~40.~~47. The utilities may continue to offer interruptible or curtailable service only until March 31, 2002 pursuant to Section 743.1.

~~41.~~48. Allocating costs related to rate limiters, costs of interruptible programs, and any rate discounts to transition cost recovery is improper and unlawful and misrepresents the costs, since transition costs are defined specifically in § 367.

~~42.~~49. The costs of interruptible discounts ~~and~~ rate limiter adjustments, and the power factor adjustment should ~~not~~ be included in ~~a separate line item~~ the distribution rate component on the customer bill.

~~43.~~50. The RGTCOMA tracks transition costs obligations and payments by rate group. During the rate freeze EPMC or SAPC allocators for transition costs shall be adjusted for changes in usage patterns pursuant to § 371.

~~44.~~51. The rate freeze must end for all customers at the same time notwithstanding the class transition cost obligations in the RGTCOMA. Rate groups that have not met their transition cost obligation cannot continue to pay these costs after the rate freeze, because such a carry over of costs into the post-rate freeze period is unlawful pursuant to §§ 367(a) and 368(a).

~~45.~~52. Once the rate freeze ends, any credit balances in the Transition Cost Balancing Account for each utility, including the difference for the amount of

CTC revenues authorized for collection and the amount actually collected, shall be refunded to customers. The funds will accrue interest at the utilities' authorized rate of return. The utilities shall propose a method to return the over-collected amounts to ratepayers in the first ATCP following the end of the rate freeze.

~~46.~~53. Pursuant to § 841 *et seq*. and D.97-09-057, SDG&E issued $658 million in rate reduction bonds in December of 1997 in order to finance a 10% rate reduction for eligible customers over the anticipated four-and-a-half year rate freeze period. According to the terms outlined in the Financing Order, the bonds will be fully repaid by 2007 and a charge to repay the bonds appears on the residential and small commercial customer bill until that time.

~~47.~~54. D.97-09-057 requires that excess rate reduction bond revenues, resulting from bonds that were unnecessarily issued, be returned to ratepayers and stated that the excess revenues must bear interest at SDG&E's authorized rate of return.

~~48.~~55. SDG&E could have chosen a more risk adverse approach by issuing the bonds when required as the rate freeze progressed. Instead, SDG&E opted for the riskier approach of issuing all the rate reduction bonds at once understanding that if it issued too many, the excess bond revenue would bear interest at the company's authorized rate of return.

~~49.~~56. We do not agree that SDG&E's proposal for a reduced interest rate, which would result in reduced refunds to ratepayers, is fair or reasonable.

~~50.~~57. A shorter amortization period for excess rate reduction bond revenues would result in SDG&E customers receiving money earlier than a longer amortization period.

~~51.~~58. SDG&E should be held to the same level of accountability for its business decisions as any other entity that enters into an agreement. SDG&E should credit and/or refund to ratepayers the excess rate reduction bond proceeds, which bear an interest rate of SDG&E's authorized rate of return. The credit and/or refund should occur as soon as possible.~~throughout the life of the bonds.~~

~~52.~~59. D.99-10-057 adopted a Purchased Electric Commodity Account (PECA) for SCE, SDG&E, and PG&E to track their purchased energy costs. PECA results in an energy rate that is designed to balance procurement costs and revenues in a given month. The purpose of the PECA account is to track the costs of purchased electricity, not the costs of operating power plants.

~~53.~~60. PG&E does not include a forecast of procurement costs in setting the PECA rate but instead charges a PECA rate based on the past month's costs. PG&E's PECA proposal does not contain enough detail for us to adopt it outright. Because we do not adopt a procurement PBR or rate capping, we need not include the other elements of PECA as proposed by PG&E.

~~54.~~61. The monthly PECA rate should be based on ~~forecast~~ procurement costs ~~for~~ incurred to serve customers to whom the rate is applied including a forecast of any procurement costs for which the utility has not received a final bill when the rate is developed,~~the given month,~~ an amortization component to account for prior month over- or under-collections, and a trended sales forecast. The amortization component will allow for true up between actual and recorded costs and revenues. Revenues should be recorded to PECA ~~net of~~ loss franchise fees and uncollectibles and under- or over-collections should earn interest at the short-term commercial paper rate as proposed by PG&E.

~~55.~~62. When rates are frozen, customers have little incentive to adjust energy usage patterns and remain unmotivated to shift consumption to the low demand times when energy prices are lowest. This is because under the rate freeze customers will pay the same price for energy whether they consume during peak hours when prices are higher due to high demand, or if they consume in the off peak hours when prices are lowest. In addition, since customers are charged for the average energy cost those that have better than average load profiles in effect subsidize those that have worse than average load profiles.

~~56.~~63. It is reasonable to adopt the ORA and CEC proposal that all customers with hourly interval meters be billed using hourly data once the rate freeze ends. This approach is consistent with our long-established policy of increasing customer price responsiveness, advancing market efficiency, and prompting lower energy prices.

~~57.~~64. We will not approve PG&E's proposal to allow customers with interval meters a one-time opportunity to remain on averaged prices once the transition period ends. Such an approach would be inconsistent with the objective of removing intra-class subsidies by having customers charged for the power they actually consume and would undermine our goal of increasing customer response to price signals.

~~58.~~65. In the post rate freeze era, PECA effectively replaces the PX credit approach as the way of setting energy rates. All elements adopted as part of the PX credit during the rate freeze should also be reflected in the post-rate freeze procurement rate. The costs booked to PECA and the resultant rate should reflect all costs adopted as part of the PX credit in the 1999 RAP for each utility. SDG&E should adjust its PECA tariffs accordingly.

~~59.~~66. The modified RAP will address forecast issues, as necessary and the modified ATCP will address reasonableness issues, including a review of procurement costs to the extent costs above the wholesale PX rate are included in the PECA.

Conclusions of Law

1. It is not reasonable or prudent to adopt a procurement PBR mechanism at this time. ~~No party has presented compelling evidence that the market structure should be changed now.~~

2. In light of the whole record, it is not reasonable or in the public interest to adopt the proposed SDG&E settlement regarding a procurement PBR mechanism at this time.

3. Pursuant to our authority over utility procurement of energy for retail load, it is for this Commission to decide when and under what conditions to terminate the mandatory buy requirement.

4. Stranded cost recovery was not the sole objective of establishing an industry-wide transition period. The four-year period is a time in which market evolution transpires, constituting a transition from a regulatory environment to one where competitive market forces determine prices. A fundamental component of that transition is the development of a ~~deep,~~ transparent, reliable Power Exchange or other similarly qualified exchanges.

5. So long as any utility continues to collect stranded costs from its customers, it is the responsibility of the Commission to ensure the integrity of that charge. The best means of accomplishing the objective of protecting the integrity of the CTC charge is to continue but expand the mandatory buy requirement to other qualified exchanges.

6. It is premature to relieve the UDCs of the buy obligation before the end of the transition period considering the Commission's ongoing proceedings to investigate broad market structure and competition issues such as the role of the UDC, competition in retail markets, and comprehensive unbundling of retail costs from distribution rates. However, the mandatory buy requirement should be expanded to permit procurement now from any qualified exchange.

7. Until the market is more fully developed at the end of the transition period, totally removing the buy requirement now would distort the operation of the CalPX or any other qualified exchange.

8. A qualified exchange provides continuous trading in a bid/ask type market, equal nondiscriminatory access and a mechanism for timely, anonymous price transparency. Its market-clearing price algorithm must be publicly available and its prices must be published at least as frequently as the Cal PX now publishes. It must be subject to audit and record verification, have a compliance unit, and offer similar, unambiguous terms of trade.

9. A qualified exchange cannot be owned, all or in a part, by a UDC or its affiliates.

10. UDCs must file advice letters detailing how an exchange meets our criteria if it seeks it to be qualified for utility purchases.

11. Advice letters should be processed expeditiously, within a 60-day period.

12. In the Preferred Policy Decision, the Commission has already ordered that the mandatory buy requirement will expire after March 31, 2002. We re-affirm our intent to lift the requirement as of this date.

13. Our actions regarding the Cal PX and other qualified exchanges and the mandatory by requirement are within the scope of this proceeding and do not contravene PU Code §1708.

~~8.~~14. Section 367 generally defines transition costs and establishes the time frame for recovery of uneconomic costs. ~~We must interpret §§ 367(e)(1) and (3) in a manner that harmonizes the statute and gives effect to every word and statement.~~ Section 367(e)(1) requires that transition costs be allocated in substantially the same proportion as on June 10, 1996.

~~9.~~15. ~~Section 367(e)(3) is not made effective subject to the provisions of § 367(e)(1). In order to harmonize these statutes, the cost allocation constraints~~

~~described in § 367(e)(1) must expire with stranded cost recovery and the end of the rate freeze. A literal interpretation of § 367(e)(1) would result in the absurd outcome of having transition costs allocated decades into the future using an outdated 1996 methodology.~~

~~10.~~16. After the rate freeze ends, the Commission retains its cost allocation authority, including its authority over allocation of ongoing transition costs, subject to the various provisions of §367(e).~~ pursuant to § 367(e)(3). Section 367(e)(3) provides for the maintenance of the firewall and rate freeze principles. Any restriction on the Commission's cost allocation authority expires with the end of the rate freeze since the firewall will be maintained and rate freeze principles cannot be violated once the rate freeze ends.~~

~~11.~~17. It is reasonable for the Commission to use the top 100 hours ~~gather further information about~~ methodolog~~ies~~y for allocation of transition costs after the end of the transition period. ~~The Commission should gather information about an allocation that is more consistent with cost causation principles than either the EPMC method of the equal cents per kwh method. The information should also show bill impacts for each customer class.~~

~~12.~~18. The § 367(e) provision mandating that transition costs be allocated in substantially the same proportion as similar costs on June 10, 1996 is not in conflict with the § 371 provision mandating allocation adjustments for changes in class energy use patterns. Therefore, during the rate freeze EPMC or SAPC allocators for transition costs shall be adjusted for changes in usage pursuant to § 371.

~~13.~~19. If we were to allow reconciliation of RGTCOMA balances post-rate freeze, this would constitute a carryover of transition costs into the post rate freeze period. Such a carryover of costs is unlawful pursuant to §§ 367(a) and 368(a).

~~14.~~20. SDG&E understood and agreed to the terms and stated risks embodied in the Financing Order.

~~15.~~21. SB 418 clarifies that the Commission has the authority to address issues regarding excess bond revenues and order alternative treatment, if appropriate. However, SB 418 does not require the Commission to accept SDG&E's preferred solution for a lower interest rate.

~~16.~~22. Section 846.2 provides that the Commission may order a credit to ratepayers of excess rate reduction bond proceeds that is fair and reasonable. SDG&E's request for a lower interest rate than that established in the Financing Order, would not be fair or reasonable for ratepayers.

~~17.~~23. The Commission should adopt a shorter amortization period for excess rate reduction bond revenues for SDG&E customers. A shorter amortization period is a fair and reasonable resolution of this question.

~~18.~~24. The Legislature has called for certain rates and optional service to be in place for a specific amount of time; e.g., § 743.1(b) requires that optional interruptible or curtailable service continue at least until March 31, 2002 and that the level of the pricing incentive shall not be altered from the levels in effect on June 10, 1996 until March 31, 2002. This section also states that this Commission is to direct the utilities to continue efforts to reduce rates charged to industrial customers without shifting cost recovery to other customer classes.

~~19.~~25. While we prefer that the utilities not implement or extend rates or discounts that could be competitive, we cannot implement such objectives at this time. Instead, a full record should be developed for our consideration in both A.91-11-024 and A.00-01-009 for SDG&E and Edison, respectively. For PG&E, we expect that issues related to load retention and special rates will be brought forward for our consideration in A.99-03-014.

~~20.~~26. A fundamental objective of electric restructuring has been to increase the customer's ability to respond to market signals serving to foster greater market efficiency, the expectation being that greater efficiencies would serve to prompt lower overall market prices.

~~21.~~27. Consistent with the requirements of D.97-09-057, D.97-11-074, and D.00-02-048, it is reasonable to require Energy Division to conduct an audit of SDG&E's Rate Reduction Bond Memorandum Account and associated savings to ratepayers. We leave it to the assigned Commissioner and ALJ to set the schedule for this audit report.

~~22.~~28. Because the Commission is encouraged to close ratesetting proceedings within 18 months (SB 960, Stats. 1996 Ch. 856), it is reasonable to ensure that the issues addressed in the modified ATCP and RAP proceedings are discrete.

~~23.~~29. This order should be effective today, so that these requirements may be implemented expeditiously.

FINAL ORDER

IT IS ORDERED that:

1. The Settlement Agreement filed by San Diego Gas & Electric Company (SDG&E), the Office of Ratepayer Advocates, Utility Consumers Action Network, the California Power Exchange (CalPX), Duke Energy Trading and Marketing, L.L.C., Hafslund Energy Trading, LLC, and California Polar Power Brokers LLC on October 27, 1999 is denied.

2. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and SDG&E (UDCs) shall continue to procure electricity from the CalPX and related markets (including day-ahead, day-of, block forward, and the Independent System Operator (ISO) imbalance energy markets) or from any qualified exchange until all three utilities have ended their

individual rate freeze periods. The UDCs shall not withdraw all purchasing from the Cal PX, but may use a mixture of purchases from it and any qualified exchange.

3. PG&E, Edison and SDG&E shall file an advice letter, separately or jointly, if they seek a determination that an exchange is qualified so as to allow purchases of its products. The exchange may comment on the filing.

4. At the end of the transition period, effective April 1, 2002, the mandatory buy requirement for UDCs shall be eliminated.

5. Pursuant to Decision (D.) 99-10-057, three months prior to the anticipated date the rate freeze will end, or no later than September of 2001, PG&E and Edison shall file advice letters informing the Commission and parties of the expected end of the rate freeze. These advice letter filings shall include all necessary tariff language and preliminary statements using the four Power Exchange price forecast scenarios described in the Phase 1 decision. In order to promote timely rate changes, pursuant to D.99-10-057, PG&E and Edison shall file a supplement to this advice letter five days following the date upon which all the criteria for ending the rate freeze have been satisfied. In these supplemental filings, PG&E and Edison shall provide the actual rates to be implemented after the rate freeze and the ratemaking mechanisms authorized by D.99-10-057 and this order. These advice letters shall serve to notify parties and this Commission of the end of the rate freeze for PG&E and Edison.

6. PG&E, Edison, and SDG&E shall continue to offer balanced payment plans to their residential customers. We shall not adopt expanded balanced payment plans or other form of rate capping, nor shall we expand balanced payment plans to streetlighting customers.

7. The subject utilities shall file a joint ~~application~~ Advice Letter within 60 days of the effective date of this decision which updates the top 100 hours

methodology for 1998 and 1999 as discussed herein~~compares the day-ahead hourly PX prices for all hours of 1999 with the load patterns (including estimated load curves when appropriate) and usage levels of each customer class. The application should then show the cost responsibility for each class over the year of 1999 for each utility. The application should also show the bill impacts for each customer class from changing from the 1996 EMPC method to a method based on the above analysis. Each utility may then propose whether this exact allocation should be used for transition costs after the transition period, some variation of this method, or some other methodology~~.

8. When the rate freeze ends, transition costs displaced because of recovery of restructuring implementation costs shall be allocated using the ~~cents-per-kilowatt-hour~~ top 100 hours methodology applied on a system-wide basis.

9. When the rate freeze ends, nuclear decommissioning costs should be allocated using a cents-per-kilowatt-hour, usage-based methodology.

10. Costs related to the California Alternative Rates for Energy (CARE) program shall continue to be allocated on a cents-per-kilowatt hour basis after the rate freeze.

11. After the rate freeze, costs related to energy efficiency public purpose programs (or non-CARE public purpose program costs) shall continue to be allocated according to System Average Percent Change (SAPC).

12. We affirm the establishment of the Public Purpose Program Revenue Adjustment Mechanism for PG&E and the Public Purpose Program Adjustment Mechanism for Edison. These accounts shall be two-way balancing accounts.

13. Costs related to rate limiters, costs of interruptible programs, and any rate discounts shall not be recovered as transition costs.

14. The costs of power-factor adjustments, interruptible discounts and rate limiter adjustments shall ~~not~~ be included in ~~a separate line item~~ the distribution rate component on the customer bill.

15. The rate freeze shall end for all customers at the same time notwithstanding the class transition cost obligations in the Rate Group Transition Cost Obligation Memorandum Accounts (RGTCOMA). During the rate freeze EPMC or SAPC allocators for transition costs shall be adjusted for changes in usage patterns pursuant to § 371.

16. Once the rate freeze ends, any credit balances in the Transition Cost Balancing Account for each utility, including the difference for the amount of competition transition charge (CTC) revenues authorized for collection and the amount actually collected, shall be refunded to customers. The funds will accrue interest at the utilities' authorized rate of return. The utilities shall propose a method to return the over collected CTC to ratepayers in the first Annual Transition Cost Proceeding (ATCP) following the end of the rate freeze.

17. SDG&E shall refund to ratepayers the excess rate reduction bond proceeds which bear an interest rate of SDG&E's authorized rate of return. SDG&E shall ~~place a check or~~ refund and/or credit on applicable customer's bills in the next feasible billing cycle for the appropriate amount to reflect the unrealized savings resulting from excess rate reduction bond proceeds, as discussed herein.

18. The monthly Purchased Electric Commodity Account (PECA) rate shall be based on ~~forecast~~ procurement costs incurred to serve customers to whom the rate applies, including a forecast of any procurement costs for which the utility has not received a final bill which the rate is developed for the given month, an amortization component to account for prior month over- or under-collections, and a trended sales forecast. The amortization component will allow for true up between actual and recorded costs and revenues. Revenues ~~should~~ shall be

recorded to PECA ~~net~~ less ~~of~~ franchise fees and uncollectibles and under- or over-collections ~~should~~ shall earn interest at the short-term commercial paper rate as proposed by PG&E. In the post rate freeze era, PECA effectively replaces the PX credit approach as the way of setting energy rates. All elements adopted as part of the PX credit during the rate freeze shall also be reflected in the post-rate freeze procurement rate. The costs booked to PECA and the resultant rate shall reflect all costs adopted as part of the PX credit in the Application (A.) 99-09-022 *et al.*, the 1999 Revenue Adjustment Proceeding (RAP) for each utility. The utilities shall adjust their respective PECA tariffs accordingly after the 1999 RAP decision is issued.

19. All bundled customers with hourly interval meters shall be billed using hourly data once the rate freeze ends.

~~20.~~We adopt a modified RAP and a modified ATCP, as described herein. The modified RAP shall address forecast issues~~,~~ as necessary, and the modified ATCP shall address reasonableness issues, including a review of procurement costs to the extent costs above the wholesale PX prices~~rate~~ are included in the PECA. These proceedings shall be filed according to the timelines established for the 1999 RAP and ATCP proceedings.

20. ~~proceedings shall be filed according to the timelines established for the 1999 RAP and ATCP proceedings.~~

21. Because SDG&E has ended its rate freeze, SDG&E shall file an advice letter to implement the provisions of this decision, within 15 days of the effective date of this decision, to be effective when Energy Division determines SDG&E is in compliance.

~~21.~~22. A.99-01-016, A.99-01-019, A.99-01-034, and A.99-02-029 are closed.

This order is effective today.

Dated ____________________, at San Francisco, California.