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Decision 01-01-019 January 4, 2001

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) to: (1) Consolidate Authorized Rates And Revenue Requirements; (2) Verify Residual competition Transition Charge Revenues; (3) Review the Disposition of Balancing and Memorandum Accounts; (4) Review Generation Cost Jurisdictional Cost Allocation; (5) Review the Reasonableness of the Administration of the Low Emission Vehicle Program; (6) Review the Administration of Special Contracts; and (7) Present a Proposal for the Inclusion of Long Run Marginal Costs in the Power Exchange Energy Credit.	Application 99-08-022 (Filed August 9, 1999)
And Related Matters.	Application 99-08-023 Application 99-08-026 (Filed August 9, 1999)

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OPINION

Summary

In this decision we adopt a Power Exchange (PX) credit adder of .007 cents per kilowatt-hour (¢/kWh) for all three utilities. We find that it is unreasonable to exempt wholesale customers from paying their fair share of Reliability Must-Run (RMR) costs and we put Southern California Edison Company (Edison) on notice that retail ratepayers will not bear the burden of 100% of the RMR costs in the future. We discuss the confusion regarding the definition and computation of long-run marginal costs (LRMC), and hold that the proper method for determining the PX credit is by use of short-run marginal costs, which was the method used by the utilities.

I. Background and Procedural History

In our opinion on Cost Recovery Plans, Decision (D.) 96-12-077, we recognized the need to streamline utility cost recovery mechanisms to effectively implement a restructured electric utility industry in accordance with Assembly Bill No. 1890 (AB 1890). Accordingly, we created the Revenue Adjustment Procedure (RAP) to review, track, and compare each utility's authorized revenue requirements with actual recorded revenues and to approve any necessary adjustments or updates to authorized revenues. Such adjustments are associated with the performance-based ratemaking (PBR) mechanism and decisions addressing such issues as power purchase contracts, public purpose programs, nuclear decommissioning, and transition costs.

A number of issues were added to the 1999 RAP by D.99-06-058, the first RAP:

1. The elimination or retention of memorandum and balancing accounts,
2. The costs associated with low emission vehicles, and

3. The administration of special contracts.

In addition, we designated the 1999 RAP as the proceeding to consider (1) requests for authorization to use recorded monthly jurisdictional allocation factors for assigning recorded system generation costs between retail and wholesale requirements customers; and (2) LRMC of energy procurement for inclusion in the PX credit provided to utility customers that elect direct access.

D.99-06-058 described the context of PX price issues as follows:

> Under the restructured electricity market in California, customers may subscribe to "bundled service" from the utility or "direct access" service from a competitive energy provider. Customers who purchase bundled service from the utility pay a PX charge to cover the utility's power supply costs, while customers who elect direct access service receive a credit on their bills called the "PX credit" that offsets the energy costs included in the bundled rate. (Id. at 20.)

In the first RAP, the Office of Ratepayer Advocates (ORA) recommended that all on-going costs related to energy procurement from the PX by the utilities on behalf of bundled-service customers including costs of maintenance, refinement, and enhancement of utilities' systems should be recovered through the PX price, and that direct access customers should be given a credit for those costs. D.99-06-058 adopted refinements to the method of calculating the PX credit, but concluded that there was not an adequate record to adopt changes to its composition at that time, and ordered its composition to be reviewed in the current RAP.

Edison, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) filed their 1999 RAP applications in

August 1999. The Alliance for Retail Marketers (ARM)[1] and ORA filed protests. The applications were consolidated for hearing.

The Federal Executive Agencies (FEA), ARM, ORA, and The Utility Reform Network (TURN) submitted direct testimony; Aglet Consumer Alliance (Aglet), the California Large Energy Consumer's Association (CLECA), FEA, TURN, the Coalition of California Utility Employees (CCUE) and applicants submitted rebuttal testimony. Evidentiary hearings began on February 7, 2000 and concluded on February 22, 2000. The proceeding was submitted on April 17, 2000 with the filing of concurrent opening and concurrent reply briefs.[2]

At a prehearing conference, the presiding administrative law judge (ALJ) directed the utilities to address how they intend to proceed at FERC to recover a fair allocation of RMR costs from the utilities' wholesale transmission customers. The ALJ directed that "each utility shall state what percentage of its transmission load is represented by its wholesale transmission customers, what steps each utility intends to pursue at the FERC to recover a fair share of RMR costs from the utility's wholesale transmission customers, and how soon each utility expects to begin [recovering] a fair share of RMR costs from its wholesale transmission customers." We affirm those instructions.

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[1] ARM is an alliance of energy service providers who actively participate in the California retail electric market, including PG&E Energy Services, NewEnergy, Inc., Enron Corp., Utility.com, GreenMountain.com Company, and Shell Energy Services. ARM members sell directly to residential, commercial, and industrial end-use customers.

[2] Briefs were filed by those parties submitting testimony, and the California Department of General Services (General Services), the California Farm Bureau Federation (Farm Bureau), and the Center for Energy Efficiency and Renewable Technologies (CFEE).

In their testimony, ORA and TURN addressed the allocation of RMR costs among retail customers, an issue that had not been added to the proceeding. PG&E filed a motion to strike this testimony. The motion was granted. Similarly, Aglet served rebuttal testimony addressing the allocation of RMR costs between wholesale and retail customers during the entire transition period (retroactive to April, 1998). Edison filed a motion to strike Aglet's testimony. The motion was granted.

II. The PX Credit

A. Introduction

The most contentious issue in this year's RAP was the computation of an adder to the PX credit. Nearly two weeks of hearings were devoted to the parties' proposals to add various costs to the credit. Some of these costs related to energy procurement; many did not. Various witnesses addressed the computation of LRMC and the effect of the default provider obligation on that calculation.

The current PX credit is equivalent to the price the utility pays to the PX for the wholesale price of energy only with no other costs added. The issue before the Commission is to determine the amount of an adder to be included in the credit to account for the reduction in the costs of electric commodity procurement incurred by the utilities; costs which are not caused by the direct access customer.

In D.99-06-058, we directed the utility distribution companies (UDCs) to address PX credit issues in this RAP. D.99-06-058 required that each UDC:

> "… shall include in their respective 1999 Revenue Allocation Proceeding (RAP) applications a PX credit calculation that reflects the long-run marginal costs of customer account

> managers, customer service representatives, self-provision of ancillary services and financing costs for purchasing power from the PX. The PX credit calculation should also include an estimate of other expected long-run marginal costs as set forth herein." (Id., at 49, Ordering Paragraph 4.)

We adopted a PX credit for each UDC on an interim basis, subject to revision based on the evidence presented in this proceeding (Id., at 24). We summarized the methodology by which a revised PX credit for each UDC should be calculated as follows:

> "Consistent with our longer-term view, we find that Enron makes a reasonable case that some of the costs it identifies may be appropriately included in the PX credit calculation, such as those associated with account managers and customer services representatives. ORA also makes a reasonable case that the costs of self-provision of ancillary services and financing costs for purchasing power from the PX should be added into the PX credit calculation. TURN and DGS join these parties in proposing that the PX credit should recognize additional costs of procurement. No such costs are adequately specified in the record for purposes of ratesetting in this proceeding, however. We will direct the utilities to include the long-run marginal costs of these functions in future calculations of the PX credit, that is, in the utilities' 1999 RAP applications. Recognizing that long-run marginal costs studies would be a difficult undertaking in the near term, we will require the utilities to use actual April 1998-April 1999 recorded costs or 1999 budgeted or forecasted costs as proxies for long-run marginal costs. The actual recorded costs should include allocations of overheads. It is our intent to review these additional PX credit items on an expedited basis in the 1999 RAP." (Id., at 24.) (Emphasis added.)

During the course of the hearings, parties developed substantial evidence on the theoretical underpinnings for determining the LRMC of UDC commodity procurement activities. The general approach, which we believe is correct, may be stated as follows:

- Marginal cost is defined as the change in cost associated with a small change in output (Helgens/PG&E, Tr. 1/12; Marcus/CCUE, Tr. 6/869).

- A "small change" in output is defined generally as a one-unit change in output. For many firms, the nature of production is such that it is very possible that the change in costs associated with a one-unit increase could be the same as that associated with a one-unit decrease, although that general rule is not always true (Helgens/PG&E, Tr. 1/12, 13).

- The term "long-run" is typically defined as a period of time where all factors of production such as labor, plant, equipment resources, and natural resources can be varied, assuming they are capable of being varied (Helgens/PG&E, Tr. 1/13, 14; Marcus/CCUE, Tr. 6/869, 870).

- The "short-run" is defined typically as a period of time where at least one factor of production that is capable of being changed over the long term remains fixed (Helgens/PG&E Tr. 1/13, 14).

- The concepts of long-run and short-run vary from firm to firm depending upon the nature and business of the firm, and the period of time necessary for the firm to have the flexibility to vary all factors of production that are capable of being varied (Helgens/PG&E Tr. 1/13, 14).

- When one combines the concepts of "long-run" and "marginal costs," one is referring to the change in cost from a small reduction (or increase), perhaps a one-unit reduction (or increase), in output where all costs related to the factors of production that are capable of becoming variable over time are in fact variable (Helgens/PG&E, Tr. 1/13; Marcus/CCUE, Tr. 6/870).

- The determination of LRMC doesn't occur in a vacuum, one must look at the firm and the industry to determine if there are any constraints (defined by such things as production technologies or legal and regulatory requirements) that will affect the ability of the firm to reach an optimum input mix by varying all factors of production (Helgens/PG&E, Tr. 1/14; Croyle/SDG&E, Tr. 3/385).

- The UDC's default commodity procurement responsibility (which applies to all its distribution customers, direct access and non-direct access alike) is a type of constraint that affects the UDC's ability to vary all its procurement related costs in the long-run (Croyle/SDG&E, Tr. 3/385, 386).

ARM, in contrast to what we believe to be the correct approach, developed a definition of LRMC based on the concepts that: 1) all costs are variable in the long run (i.e., all inputs are variable); 2) calculations should be based on the increment between serving all customers and serving none; and 3) LRMC should include all attributable costs, including overheads. Essentially, ARM takes the total costs of the utility procurement services and divides these costs by total kWh services to develop procurement credits expressed in cents per kWh.

ORA takes a more pragmatic approach. It argues that costs associated with one function should not be allocated to other functions. To develop competitive markets, costs must be unbundled to avoid cross-subsidies. Procurement is a function separate from distribution and must be priced separately. ORA concludes that the only supportable allocation of procurement costs is to allocate all costs to bundled service customers. ORA contends that charging direct access customers for these procurement costs would result in charging them for costs of services that they have chosen to forgo, by selecting energy service providers (ESPs) other than the utility. In addition, ORA believes that customers would be double charged because they would be paying for the same services from the ESP. Unbundling to avoid double charges, ORA believes, is consistent with Commission policies for LRMC-based pricing of telecommunications service, as well as in the gas industry. ORA asserts that the term “long run marginal costs” has appeared in a variety of Commission decisions, and the outcomes of those decisions demonstrate that charging customers only for services that they choose to use (e.g., by remaining on bundled service) is consistent with the Commission’s view of LRMC pricing. In ORA’s opinion, even if part of the utilities’ procurement costs were attributed to default service, the utility’s cost of commodity procurement is not a distribution cost, and should not be intermingled with distribution costs.

The UDCs proposed much smaller credits because of their disagreement with ARM and ORA over the costs attributable to procurement; the fraction of these costs which are variable; and whether the LRMC should be calculated based upon serving all customers, just direct access customers, or a single customer.

The parties’ LRMC PX credit adder recommendations are summarized in the following table.

PX Credit Adder Recommendations[3] (Cents per kWh)			
	Edison	PG&E	SDG&E
Edison*	0.007		
PG&E		0.002	
SDG&E			0.003
ARM	0.067	0.059	0.049
ORA	0.040	0.048	0.015

*Edison originally recommended an adder of .002, but later recommended .007.

B. Discussion

Our preliminary concern is with the parties' interpretation of long-run marginal costs, especially the interpretation used by ORA and ARM. In our opinion, ORA and ARM have placed too literal an interpretation (all things change in the long run) on what is a theoretical economic term. The fault, in part, lies with our sometimes too imprecise use of the phrase "long-run marginal costs" without reference to the seminal case, which most clearly sets forth our views on the subject. In Edison's Test Year 1995 general rate case (Application (A.) 93-12-025) we issued D.96-04-050 (65 CPUC2d 362) in which we exhaustively reviewed the concepts of long-run and short-run marginal costs. Selected excerpts include the following:

> "A major issue of contention in this proceeding concerns the time frame over which marginal energy costs should be considered. As applied to marginal or avoided costs, 'short-

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[3] Other parties did not present evidence on marginal costs. CCUE and the Farm Bureau support the UDCs. CFEE supports ARM. General Services urges us to reject the UDCs' recommendations, but makes no specific recommendation regarding the proper PX credit.

run' and 'long-run' do not refer to a particular period of real time, but rather the flexibility which the utility has to adjust utility plant or its operation in response to a change in output.

"The 'short-run' refers to a situation in which the utility's plant or fixed cost obligations remain constant, but the operation of the system can be varied. In the 'long-run,' all aspects of the economic equation can be changed, including fixed assets (plant), fixed obligations under contracts, and all variable inputs. Whether a short-run or long-run marginal cost analysis is appropriate depends on the pricing problem at hand.

"Since the inception of marginal-cost based rates, we have generally applied the principle that short-run energy and demand costs are the correct way to conceptualize marginal costs for ratemaking. As we stated in D.93887, in PG&E's test year 1982 GRC, 'customers should be signaled the present cost of consumption for ratesetting purposes.' We held that short-run marginal costs should be used for both revenue allocation and rate design purposes. We adopted a short-run methodology consisting of an energy component and a short-age cost component, which we currently use today." (Cites omitted.)

* * *

"We have considered similar arguments in prior proceedings.

> "Our objective through regulation is to act as a substitute for competition. In the market place the consumer is not always confronted with pricing which reflects long-term marginal costs. For example, look at today's gasoline prices. With the current glut in oil supply we are paying prices which could hardly include a value for shortage costs. In the past when the supply was scarce the reverse was true. Likewise, it is appropriate to reflect current

> energy prices whether they are below or above long-term fuel forecasts.
>
> "We find this rationale even more compelling today than it was nine years ago. One only has to look at the daily price volatility in the gas commodity market (Exh. 21) to recognize that market prices do vary significantly in response to short-run supply and demand conditions. As the electric industry is restructured, it too will take on the attributes of a dynamic competitive market. In such an environment, this Commission's ability to moderate price fluctuations and administratively determine a long-run equilibrium price will be both inappropriate and impractical. Proposals in our electric industry restructuring proceeding are consistent with an approach that prices on short-run market signals, particularly for electric generation services. None of the parties to that proceeding, including Edison, propose to unbundle and price these services based on long-run marginal costs.
>
> "Our policy of basing regulated prices on short-run marginal costs is also consistent with economic theory. As described in Attachment 3, the market price at any given point in time is determined by the intersection of the market short-run supply and demand-curves. Reaching an optimal long-run equilibrium is the theoretical result of market pricing over time, but industries seldom stand still long enough for this equilibrium to be achieved. (Exh. II-81, pp. 35-36.) <u>Consumers and suppliers constantly interact on the basis of short-run price signals, and we believe that electric ratesetting should follow suit</u>. (D.96-04-050, 65 CPUC2d at 362, 387, 388.)" (Emphasis added.)

We concluded our pricing discussion in D.96-04-050 by including a theoretical marginal cost pricing analysis, which determined that "the process of arriving at a long-run equilibrium, which represents the optimal allocation of resources, is an iterative process based on market responses to short-run prices." (65 CPUC2d at 476.) Thus, D.96-04-050 teaches that the path to reaching long-run marginal cost pricing is by way of an iterative process of a short-run analysis which itself is in constant flux. Industries seldom stand still for equilibrium to be achieved. Those principles apply to this RAP.

We seek an equilibrium price, which is a long-run marginal cost, but we cannot determine it without first going through a short-run marginal cost exercise. The utilities have recognized this by providing what they call a long-run marginal cost analysis, which under theory is sometimes referred to as "short-run," but meets our requirements. ORA and ARM also call their theory long run, but actually it is nothing more than average costs, which does not meet our requirements. The goal is to determine LRMC; as we have demonstrated, this equilibrium is achieved by a short-run marginal cost analysis.

Of the numerous Commission decisions dealing with the issue of "unbundling" utility services, two have particular application to the PX credit.

In D.97-08-056 we said:

> "This proceeding is part of the Commission's larger effort to promote competition in electric generation markets. Decision (D.) 95-12-063, as modified in D.96-01-009, set forth in general terms the Commission's policy in matters concerning electric industry restructuring. . . . The order identified the need to disaggregate electric utility rates by 'unbundling' generation, transmission and distribution for all direct access customers. This proceeding is the Commission's forum to accomplish such unbundling."

* * *

> "The purpose of unbundling, as we have stated many times, is to promote the development of competitive markets for generation services. The purpose of promoting competition

where it may be viable is to assure the best use of the economy's resources, to assure customers pay the lowest price for services, and to expand the array of services available to customers. Unbundling promotes competition by providing customers with options for individual services and sending customers price signals which would permit them to make reasoned choices about their competitive options."

* * *

"In pursuing a policy to promote more efficient generation markets, we reject proposals to allocate to monopoly functions any costs associated with services that are or will be subject to competition. Specifically, we will not permit allocations of generation cost to distribution customers. To do so would compromise market efficiency by producing artificially low utility generation rates (or utility profits which do not correspond to utility risk) and provide competitive advantages, which would stifle competition to the utilities. Moreover, any allocation to monopoly customers of costs associated with competitive products would be unfair to monopoly customers because they would, in effect, be required to subsidize shareholder profits.

"It is not our intent to deny utilities an opportunity to recover reasonable costs which they actually must incur, but we must balance this with our need to ensure that ratepayers are not paying for costs that no longer exist." (D.97-08-056, pp. 6-8, 24.)"

In D.99-06-058, the first RAP, we said:

"Failure to recognize real cost savings in the PX credit, or to require direct access customers to assume costs for which they are not responsible may compromise efforts to promote competitive markets."

* * *

> "We have consistently stated our view that firms must recover their long run marginal costs in order to remain viable. Recognizing this, D.98-09-070 directed the utilities to present long run marginal cost studies for their revenue cycle services. The same concerns apply here. If we are to promote competition in generation markets, utility commodity prices must ultimately recognize those costs which the utilities must recover in the long run as any other provider. Our long term strategy is to create an industry structure in which the utilities are one of many competitors." (D.99-06-058 at p. 23.)

The Commission has postulated two principles to guide our decision in this case: The impact on utility costs caused by customers obtaining electric commodity procurement services from ESPs (direct access customers) should be determined by the use of LRMC pricing (D.99-06-058, Ordering Para. 4, at p. 49); and direct access customers should not pay for services not received (D.99 06-058, at p. 23). As applied to the evidence presented in this proceeding, the two principles are in conflict.

Our analysis starts with the observation that the direct access customer of the ESP remains a distribution customer of the utility. The direct access customer still calls the utility to turn on power, to discuss billing concerns, to complain about power outages, to seek reconnection, line extensions, etc. Thus, when a customer opts for direct access, he or she remains a distribution customer requiring all the services that the utility typically provides, except commodity procurement. As discussed below, the LRMCs of the utility do not change when a bundled customer becomes a direct access customer.

However, from the direct access customer's position, the situation has changed. The customer no longer obtains electric commodity procurement service from the utility, and obviously should not have to pay for it. The customer should receive a credit on his or her bill which reflects the costs that the customer should not be paying. This is different from the costs the utility saves by not performing procurement services for the direct access customer. Herein, the contradiction: the utility has no change in marginal costs when the bundled customer becomes a direct access customer, but the direct access customer no longer receives procurement service from the utility and shouldn't have to pay for it.

Adding to the equation is the concern that if the utility's costs are not reduced by direct access, its revenue requirement is not reduced; therefore, any credit to direct access customers will, perforce, be recovered from all distribution customers. The likeliest result is that in the short run the overall cost of electricity delivered to the end-users will increase.

To put our discussion of costs in perspective, we note the current amount of direct access penetration is approximately 2.5% of total electric customers.

Utilities	Total Electric Customers	Total Direct Access	Residential Direct Access	Commercial Direct Access	Other* Direct Access
PG&E	4,000,000	101,250	69,750	11,250	20,250
Edison	4,000,000	99,000	68,200	11,000	19,800
SDG&E	1,000,000	25,200	17,500	2,750	4,950
Total California**	9,000,000	225,450	155,450	25,000	45,000

*"Other" includes industrial, public authority, and agriculture customers.
**All numbers are reasonable approximations.

1. The LRMC of Procuring Electricity

We have reviewed the principles of LRMC analysis above. In this proceeding, we are to determine the change in cost associated with a small change in output, i.e., the procurement of the electric commodity.

The utilities argue that although the factors of production may theoretically vary in the long run, the actual costs may not change at all, particularly with marginal changes in output. Energy procurement costs fluctuate little, if at all, with an increase in customers or an increase in load, even in the long run. For example, the amount of work and associated costs involved in bidding energy does not markedly diminish if a firm procures less energy from the PX: Bidding 200 megawatt- hours or 100 megawatt-hours involves the same amount of work and associated costs. Therefore, unless an electric utility can leave the market completely, it will be forced to incur these procurement costs and the costs will not vary on the margin.

A utility's ability to reduce its costs while reducing a unit of output can also be constrained by legal or regulatory mandates, activities that the utility is obligated to perform. For that reason, even in a LRMC calculation, some costs would be fixed. In this proceeding, the default service obligation constrains the UDC's ability to reduce its total energy procurement costs. Unlike ESPs, which can leave the market whenever it becomes unprofitable, the UDC must maintain an infrastructure that can bid into the markets and procure energy for any potential customer in its service territory. Therefore, the default service obligation limits a utility's ability to reduce its procurement costs even when customers switch to direct access.

ARM's position is diametrically opposed to that of the UDCs'. ARM argues that "LRMC calculations should be based on the increment between serving all customers and serving none" (O.B. p. 14). ARM disputes that this method produces an "average" instead of a "marginal" cost. ARM maintains that this approach is appropriate for estimating marginal costs when inputs are "bulky" and their costs insensitive to changes in demand over large increments. Treating costs for "bulky" inputs (*i.e.*, those for which a single increment serves many customers) as fixed is, in practical terms, the same as conducting a short-run analysis. In the long run, all inputs and their related costs should be treated as variable. The question is how to account for "bulky" inputs in calculating costs in the long run and on the margin. This is essentially the method for calculating LRMC proposed by ARM, *i.e.*, measuring the incremental cost between serving no customers and serving all customers.

ARM says the rationale for its approach is clear. Whenever there are large volume-insensitive inputs, this in effect means that the marginal cost of the first unit of production is high relative to the marginal cost of subsequent units. Put another way, the cost that a utility could avoid by not serving its last customer (*i.e.*, assuming almost 100% penetration by ESPs) would be astronomically high relative to the customers that left before. The point of measuring the increment in costs between serving no customers and serving all of them is that it captures the marginal cost of serving the "last" customer and spreads it over all potential customers, and it leads to uniform marginal costs across similar customers. According to ARM, this approach also makes sense because it ensures that long-run cost estimates include all costs necessary for the provision of a service.

We are not persuaded by ARM's argument. What it calls "LRMC" is merely average cost. It turns marginal cost theory upside-down. It takes total procurement costs - the cost of the entire quantity of service provided - and divides by total system kWh. This is clearly not the cost that would vary with a small change in output; nor is it the measure of that cost. LRMC is the change in cost associated with a <u>small change in output</u>, over a long enough time that all factors of production that are capable of varying can be changed. Even when allowing all factors of production to change, some costs do not vary unless a firm exits the market entirely and thus will not vary with a small change in output. And, if a firm is prevented from leaving the market, certain costs - whether marginal or total - cannot be reduced at all. Any other calculation - like ARM's proposal of dividing procurement costs by total system kWhs - is not LRMC and is not what the Commission ordered in D.99-06-058.

Edison, PG&E, and SDG&E each made essentially the same presentation regarding the effect of LRMC theory on changes in costs which reflect changes in the number of direct access customers. Their presentations, and their conclusions, were to the effect that a small change in the number of direct access customers has no effect, or perhaps a de minimus effect, on costs. Because of the similarity of presentations, we will limit our analysis to that of the presentation of Edison. We will apply our conclusions to Edison, PG&E, and SDG&E.

Quantification of Parties' PX Credit Recommendation for Edison Assuming Annual Distribution of 79,470 GWh				
Party	(1) ¢/kWh Recommendation	(2) Total[a] Procurement Costs ($)	(3) Direct Access Penetration	(4) Total Costs[f] Edison will Allocate to PX Credit ($)
Edison[b]	.002	1,590,000	.025	39,750
Edison[c]	.007	5,560,000	.025	139,000
ORA[d]	.040	31,800,000	.025	795,000
ARM[e]	.067	53,260,000	.025	1,331,500

[a] ¢/kWh x 79,470 GWh.
[b] Edison testimony, Ex. 10, p. 147.
[c] Edison O.B. p. 57.
[d] ORA O.B. p. 15.
[e] ARM O.B. p. 37.
[f] Col. 3 x col. 2.

Edison's witnesses testified that the costs associated with procuring energy do not vary with the amount of energy procured. These costs – which include, among other things, preparing a day-ahead schedule, submitting hourly bids, forecasting weather, and reviewing PX settlement statements – are necessary regardless of the amount of energy procured. The costs of procurement are not reduced when load decreases. A witness testified that if Edison lost one-third of its bundled service customers to ESPs tomorrow, its cost of procuring energy would not be affected because the process of procuring energy involves estimating and bidding the load of the aggregate of its customers. Each day Edison prepares and submits a single, day-ahead schedule, 24-hour hourly loads, and typically a real-time schedule. The same effort will be expended whether Edison estimates the bid for 2 million customers as it would be for 3 million customers. Edison's procurement function is currently staffed by four full-time analysts. That same level of staffing would still be required even if Edison were to provide service to 400,000, rather than 4,000,000 bundled service customers. The costs of daily and hourly forecasting, preparing and submitting schedules, and performing a cost accounting for the monthly invoice from the PX do not vary by the number of customers. The direct costs of procuring energy are a function of whether the transaction is done or not done.

Edison also argues that the intervenors have attempted to allocate functions and costs to the PX credit that do not relate to energy procurement at all. Edison explains that this is true because whether or not a customer chooses bundled or direct access service, that customer will be an Edison distribution customer. The customer will still call Edison when he or she wants to turn on power, or if the wind causes a temporary power outage. These issues do not disappear when a customer elects to receive commodity energy from an ESP.

An Edison witness described the activities performed by its Customer Service and Information (CS&I) employees. The activities of customer account managers, who work with larger customers, do not vary with the amount of energy procured from the PX. The witness said, "the bulk of work performed by those CS&I personnel who are directly involved with customers consists of preparing detailed economic analyses of methods of service, providing assistance with billing and credit issues, dealing with service-related issues, such as power quality and planned outages, cogeneration options, distribution condemnations, rate options, etc. These types of studies take weeks of effort, and relate to the distribution function, not to energy procurement." (Exh. 11, p. 30.)

The witness testified that the functions of customer service representatives who interact with smaller customers are distribution-related, and are thus insensitive to the cost or volume of energy procured for bundled service customers. Edison's call center activities do not vary with the level of PX revenues. Edison's call volumes are dominated by inquiries about bill payments, billing, turn-ons and turn-offs, reconnection and outages, primarily from residential and small commercial customers. Direct access inquiries are less than 1% of call volume. The vast majority of call center transactions, and, therefore, call center costs, would be unchanged, whether Edison secured another kWh of energy.

Edison contends that this is also true for regulatory and legal costs. As a regulated entity subject to the jurisdiction of various commissions, Edison must respond to requests from regulators. Unlike ESPs, Edison is required to be involved in many cases and issues, most of which have nothing to do with PX energy procurement. These legal and regulatory costs stem from Edison's position as a regulated utility and they will not go away unless and until Edison is no longer subject to the oversight of the Commission and other regulatory bodies. They do not vary with the number of direct access customers, load, or the overall cost of PX energy purchases.

Edison contends that the costs of energy procurement are not reduced when customers choose direct access service, even if one looks only at a large, rather than a small or marginal, reduction in the amount of energy procured by Edison. Energy Supply and Marketing costs, which relate to the actual procurement of energy, do not vary, whether Edison procures 10,000 mWh or 20,000 mWh. Other costs – such as customer service costs, regulatory costs, and legal costs – relate primarily to distribution and to the total number of retail customers served by Edison's transmission and distribution system, not to the proportion of direct access service customers.

Edison asserts that the PX credit must account for Edison's default provider obligation. The utilities are required by law to be the default provider of electric service in their respective service territories. Edison maintains that this default service obligation serves as a constraint on the utilities' ability to reduce their procurement costs to zero. It also precludes, in Edison's opinion, the implementation of ARM's "all or nothing" approach to reformulating the PX credit, where one looks at each UDC's total, rather than marginal, energy procurement costs and allocates all of them to the PX credit. Since Edison cannot exit the energy procurement business, it believes it is improper to include all of Edison's energy procurement costs in the PX credit, as ARM and ORA propose.

We agree with Edison. Edison's default service obligation is grounded in Section 366(a) of the Public Utilities Code, which states, in pertinent part: "If no positive declaration is made by a customer, that customer shall continue to be served by the existing electrical corporation or its successor in interest." The importance of the default service obligation was emphasized by the Commission in D.97-05-040, at pp. 49, 88:

> "The idea of the UDC serving as the default provider is to ensure that everyone is provided with electricity, because electricity is an essential commodity. Anyone who pays for the service should be allowed access to it. Accordingly, the UDC shall be obligated to serve any customer who no longer engages in direct access."

The default service obligation means that Edison is responsible for providing commodity service to two categories of customers: (1) those in Edison's service territory who never elected to switch to direct access service, and (2) those who at some point in time engaged in a direct transaction for commodity supplies with an ESP, but who have subsequently returned or been returned to Edison. The latter category could include customers who were dissatisfied with the ESP's service and customers whose service was discontinued by the ESP because the ESP went out of business, stopped serving specific categories of customers as a matter of internal business strategy, or discontinued serving a specific customer due to a legitimate reason such as a customer's failure to pay its bill. The responsibility to serve this second category of customers is referred to as "Provider of Last Resort (POLR)."

Default responsibility is not limited to the POLR obligation. The utility must be ready to provide basic commodity service to all customers at all times. Therefore, Edison maintains, and we concur, the relevant issue is not the probability that a direct access customer returns to bundled service, but the cost of having the basic infrastructure in place to be able and ready to provide basic commodity service to any customer who requests it. As ARM itself notes, 98% of all customers are currently availing themselves of this basic service.

The default provider obligation distinguishes the utilities from ESPs, and influences the calculation of the PX credit. ESPs admit that they are not legally required to provide service to every potential customer. For this reason, ESPs can choose to serve only those electric commodity customers with fairly constant usage, which can decrease the complexity of the bids and reduce costs. They can exit the market, or any segment of the market, at any time they believe it has become unprofitable. The utilities, by contrast, cannot refuse service to any customer and cannot exit a particular segment of the market.

2. Unbundling

Our analysis of marginal costs does not resolve the entire determination of the appropriate PX credit. From the utility's viewpoint, the marginal cost of increasing or decreasing a small number of procurement customers, who remain distribution customers, is zero or very close to zero. But from the direct access customer's viewpoint, the customer is not receiving procurement service and should not have to pay for services not rendered. It is irrelevant to the direct access customer that the utility's costs have not been reduced. If we were to adopt the utilities' position we would accept the situation that a bundled customer and a direct access customer pay the same rates (plus the cost of PX energy) despite the fact that the utility does not provide procurement service for the direct access customer. This is an improper and unreasonable result which should be rectified by unbundling the commodity procurement service and associated costs from the balance of the utility's system. Unbundling itself leads to the anomalous situation that the direct access customer appears to save money on procurement, but the utility's costs are not reduced and may actually increase because of the unbundling. This anomaly will manifest itself in the utility's next revenue requirement application.

It is the concept of unbundling commodity procurement from all other services provided by the utilities that drives ARM's and ORA's presentations. While paying lip-service to LRMC methodology (as the utilities do, also) ARM has constructed a proxy procurement company using current costs from which they derive their PX credit, and ORA has done a comparable analysis. As their arguments are essentially similar, we will concentrate on ARM's.

ARM argues that utilities provide only a relatively small commodity credit to direct access customers. As long as the PX credit understates the potential long-term cost savings to the UDC from direct access, ARM believes that utility shareholders can profit from these potential over-payments. This is true, according to ARM, because a utility has the ability to reduce its operating cost without reflecting that reduction in the PX credit. This can provide substantial anti-competitive incentives to the utility. However, the passive profitability and the anti-competitive incentives of the UDC through procurement can be addressed through approval of an appropriate PX credit.

ARM asserts that inadequate or understated PX credits harm both ESPs and direct access customers. Customers are denied the credits which would enable them to incur greater energy cost savings by electing to utilize an alternate, direct access supplier. This provides a disincentive to participate in direct access because of the widespread perception among customers that direct access is not worth the trouble because the savings are so small. ESPs are harmed because this disincentive to customer participation in direct access reduces the potential market which is available. To have sustainable profit opportunities for ARM's members, there has to be an adequate PX credit which permits them to compete with the UDCs as one of many competitors. If direct access customers are forced to shoulder costs for which they are not responsible, the state's efforts to promote competitive markets may be compromised.

To create a model for the adequate PX credit, ARM developed the concept of the "Utility-Operated Energy Service Provider" (the UOESP). In effect, ARM believes that embedded in each of the utilities is an enormous UOESP that serves almost 98% of the customers in their service areas. In order for customers to make a fair comparison between ESP and UDC electricity prices, they need to see the costs of each utility's ESP as if it were a stand alone ESP business, operating with its own profit and loss statement.

According to ARM, the UOESP has the exact same cost areas that any other ESP would have. These costs include wholesale procurement, customer service functions, various corporate support functions, and various general and administrative costs, including those related to human resources professionals, payroll staff and accounting staff, information technology staff, educational materials for customers, public relations staff, a staff of attorneys and regulatory specialists, executive staff, and consultants. The UOESP must have cars, computers, telecommunications systems, telephones, pagers, personal communication devices, and furnished offices. None of these UOESP costs are currently included in the PX credit.

Examples of such additional costs include but are not limited to:

- Legal and regulatory costs.
- Local government account representatives.
- Costs of self-provision of ancillary services.
- Block forward market financing costs.
- Other risk management costs, such as firm transmission right acquisition costs.
- Advertising costs.
- Load research costs.
- Cash working capital costs.

ARM advocates that the only way to truly get at cost separation is to have the utilities functionally separate their retail energy function from their distribution function, so that these functions deal with each other on an arms-length basis. ARM recommends that the Commission order the UDCs to file new applications that explicitly separate UOESP costs from transmission and distribution costs. ARM believes that the Commission should order each UDC to either structurally separate its UOESP from its wires business or file a bottoms-up proposal for its UOESP business, both by no later than September 1, 2000. Using this approach, ARM also advocates elimination of the PX credit in the post-freeze market; adoption of a PX charge mechanism in this proceeding which would be applicable to SDG&E immediately and to Edison and PG&E when they end their respective rate freezes; and the building of rates using a bottoms-up approach which will ensure that direct access customers do not subsidize bundled service customers. In the meantime, ARM proposes that the Commission adopt ARM's conservative LRMC retail energy cost estimates in full.

We reject ARM's recommendation of a UOESP. ARM would have us create a proxy company, with proxy employees, and proxy costs in place of a real company, with real employees, and real costs, to increase the UDC's costs so that ESPs can compete. That is not competition, it is subsidization, which we are not prepared to authorize. ARM would have us ignore the economies of scale that the UDCs provide, ignore the default providers-of-last-resort function of the UDC, and especially, ignore the uncontroverted testimony that the marginal cost of a small increase or decrease in direct access customers has no appreciable effect on the UDCs' costs. Direct access customers should not have to pay for services not received, but that reduction in payment should be based on utility costs, not those of a fictional company. We also reject ARM's panoply of services that it would have us consider as part of the procurement function of a utility to the extent that they differ from Edison's.

ORA, although not recommending a UOESP, supports ARM's analysis. ORA points to the inconsistency between the showings of the three utilities. It believes that should this continue in future reviews of their procurement costs, the Commission would not be able to completely resolve the separation of procurement costs from distribution costs. ORA proposes that we avoid this situation in future proceedings by establishing a standard definition of pertinent functions with other pertinent activities added as identified by ARM. The utilities should then be expected to record their costs in a way that is directly translatable to the Commission's standard definition of procurement functions, so that audits can be conducted to verify that all pertinent costs have been recorded in this transparent manner.[4]

We reject ORA's proposal for the same reasons we reject ARM's; ORA proposes to include functions in the calculation of the PX credit that have no relationship to procurement or to utility costs of procurement. Nor are we prepared to order the three utilities to standardize their methods of determining the PX credit. A uniform system of accounts for procurement is not necessary. As we discuss below, the presentation of Edison with its categorization, is adequate to determine the proper PX credit.

Again, we use Edison's proposal as a reasonable model. We consider the comparable analysis of ARM and ORA and find they are so far removed from the real world of utility ratemaking as to render them useless.

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[4] The point of unbundling is to encourage competition, to reduce costs to benefit ratepayers. For example, in Public Utilities Code Section 330(a), the Legislature declared its intent that rates for residential and small commercial customers be reduced

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Comparison of Edison, ORA, and ARM Proposed PX Credit Adder[5]			
	EDISON*	**ORA****	**ARM*****
	LRMC ($)	LRMC ($)	LRMC of Serving All Customers ($)
Energy Supply and Marketing	3,970,000	12,300,000	6,316,289
Market Monitoring and Analysis	0		670,000
Customer Service	1,500,000	14,900,000	17,960,368
Customer Representatives	0		9,745,843
Capital – Demand Bidding	0		709,838
Capital - CIS System	0		5,955,841
Capital – Working Cash	0		9,913,540
Total	5,470,000	27,200,000	51,271,719
PX credit (cents/kWh, assuming a load of approximately 79,470 GWh)	.007	.040****	.067

* Edison, O.B., p. 56.

** ORA Exh. 49, pp. 6-10.

*** ARM, O.B., p. 37.

**** ORA increased its recommended PX Credit Adder from .034 to .040, to reflect its proposal to assign all procurement costs to serving bundled service customers. (ORA, O.B., p. 16.)

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by 20% from the rates in effect on June 10, 1996. Everything connected with the PX credit issue shows a substantial increase in costs.

[5] The parties denominated their costs as LRMC but from our analysis these costs apparently are current actual costs. (See, D.99-06-058, p. 24.)

We will discuss in detail Edison's Energy Supply and Marketing (ES&M) cost. The balance of the categories in procurement costs will be discussed in summary fashion to avoid repetition.

a) ES&M Costs

Edison's ES&M department performs many functions relating to both supply (generation) and demand including generation bidding and scheduling, real-time operations and dispatch, management of existing power and fuel (coal and gas) contracts, weather forecasting, demand forecasting and bidding, generation and demand meter data management, demand usage reporting, and PX/ISO settlements. Portions of some of these activities relate to Edison's procurement of PX energy. The major portion of these activities also support the distribution function of Edison.

An Edison witness testified that ES&M's 1999 Office and Maintenance (O&M) budget is $14.381 million. This amount includes all Pension and Benefit (P&B) payroll loadings and department overheads. Of this amount, $4.165 million is estimated to be demand related. To arrive at this value, the ES&M managers were interviewed individually and asked to estimate the amount of direct costs in their budgets dedicated to demand-related functions, supply-related functions, and transmission-related functions. These managers determined which of the employees reporting to them were dedicated to which functions and how they apportioned their time among various functions. P&B loaders were then applied to direct personnel costs. Department overheads such as administration costs and use of the general office were allocated to various functions in proportion to the number of personnel dedicated to each function. ES&M department expenses for computer services are included in the budget of the Systems Support division of ES&M. These costs were spread to various functions according to the estimates of the Systems Support manager on a project-by-project basis.

These interviews yielded the results set forth in the table below:

CATEGORY	BUDGET ($000)	PORTION PROCUREMENT RELATED	AMOUNTS RELATED TO PROCUREMENT ($000)
Energy Supply and Marketing			
Demand Forecasting and Bidding	1,209	80%	967
Management of Existing Power Contracts	837	0%	0
Day Ahead Scheduling	782	0%	0
Day Ahead Bidding	725	10%	72
Real Time	1,352	10%	135
Usage Metering	448	25%	112
Settlement	702	35%	246
Energy Planning	2,008	30%	602
Regulatory Support	588	30%	170
Gas Contracts	141	0%	0
Coal Contracts	1,059	0%	0
Finance and Administration	1,104	65%	718
Systems Support	2,674	30%	802
Management	674	0%	0
Weather Data, Inc. Consultant	46	100%	48
Systems Consultant	50	100%	50
Capital			48
Total ES&M	14,381		3,970[6]

[6] The difference between the $4.165 million of demand related costs referred to on the preceding page and the $3.970 million is that Edison reduced its demand forecasting

Footnote continued on next page

Edison's identification and classification of its ES&M costs is far superior to that done by ARM or ORA. ARM's knowledge of what the employees in this department actually do was limited. ARM's allocation is flawed. Where groups appeared to ARM to be working on both demand and supply, ARM simply allocated the costs in proportion to the kilowatt-hours of supply or demand bid.

Edison argues, and we agree, that ARM's inaccurate methodology yielded results that have no basis in reality. For example, ARM assigns about 55% of the costs of the Day Ahead Bidding and Real Time Bidding groups to demand. However, all of Edison's demand bidding is done by the Demand Bidding and Forecasting group. The Day Ahead Bidding and Real Time Bidding groups bid only supply sources into the PX and ISO. The reason that Edison attributed 10% of these costs to demand is that Edison bids its Eastwood Pumped Storage Hydro facility into the markets, and because sometimes this facility is a large load, the manager of the Day Ahead Bidding group coordinates with the Demand Bidding Manager.

ARM also makes the mistake of assigning all of the Demand Bidding group's costs to costs associated with PX procurement. As Edison explained in its testimony, this group also provides the long-term demand forecasts that Edison has always used for rate design, revenue budgeting, distribution planning, etc. Edison will always need to perform this task, even if Edison never procures another kWh for delivery to retail customers.

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and bidding estimate by 20% to account for demand forecasting that is required whether or not Edison procures any kWhs for retail customers.

Edison argues, and we agree, that ORA's analysis is also flawed. ORA used an "all or nothing" approach, allocating 0% of a few functions to supply and 100% or almost 100% of the remainder to demand. This results in 79% of ES&M costs being allocated to demand. Even ARM in its analysis determined only about 44% was demand related.

ORA notes that Edison performs bidding and scheduling of utility-owned resources and contract resources into the PX and ISO markets. Similarly, ORA notes that Edison models and analyzes utility resources. Despite these descriptions, ORA assigns 100% of the costs of these functions to procurement. Similarly, ORA assigns 95% of the costs of Settlements and Finance to demand, even though the number of Edison's transactions involving energy deliveries and ancillary service provisions by its generation plants and Qualifying Facilities (QF) and inter-utility contracts dwarfs the number of transactions with the PX involving energy procurement for bundled service customers.

b) Market Monitoring and Analysis

Edison maintains a regulatory function - PX Monitoring and Analysis - that interfaces with the PX and ISO. This function monitors the performance of the markets, interacts with all market participants interested in the success of not only these markets, but restructuring in general, and analyzes the performance, interaction and competitiveness of the PX and ISO markets. As explained in Edison's direct testimony, after assigning the proper overheads, the relevant 1999 budget for the PX monitoring function is $0.67 million. These costs can never be avoided as long as Edison is the default service provider of energy in its territory. These costs should not be in the PX credit because they are necessary for the efficient functioning of the market, to the benefit of all market participants.

c) CS&I and Customer Service Representatives

Perhaps the most seriously misunderstood component of the various PX credit proposals is CS&I costs, which Edison budgeted at $23.4 million. These costs are overwhelmingly related to the distribution function, not to procurement of energy from the PX. These costs are not avoided when customers choose direct access service, because the customers remain distribution customers of Edison. Nevertheless, Edison put $1.5 million of these costs into its list of procurement costs.

ARM's proposal for allocating 43% of Edison's CS&I costs to procurement has serious flaws. First, ARM ignores the obvious fact that CS&I costs are distribution-related. ARM allocates CS&I costs according to the ratio of PX revenues to total revenues less Competition Transition Cost (CTC) revenues, an allocator that is totally arbitrary and has nothing to do with LRMC or with the types of functions performed by CS&I employees. According to this method, ARM allocates 43% of CS&I costs to procurement. This means that Edison's customer service representatives spend 43% of their time marketing PX energy to customers; a conclusion with no basis in reality.

ORA's position - that the entire amount attributed to customer account managers and customer service representatives simply be included in the PX credit - is similarly devoid of substance. The evidence supports Edison's position that these employees devote almost no time to procurement activities.

3. The Uniform PX Credit

As discussed above, the optimum PX credit based on the evidence for Edison is .007¢/kWh. In our opinion, the public interest requires that the PX credit be identical for all three utilities - Edison, PG&E, and SDG&E. Although we have not discussed in detail the elements of PG&E's and SDG&E's original recommendations, they are sufficiently close to each other - PG&E's .002¢/kWh - SDG&E's .003¢/kWh - and close to Edison's original recommendation of .002¢/kWh - that we are confident that an analysis similar to that done for Edison would reach a comparable result. All three utilities have essentially the same structure, especially regarding procurement. While they differ in accounting categories and wage scales, those differences are negligible in comparison to the benefits received from a uniform state-wide credit.

For the ESPs, a uniform PX credit results in a more level playing field: between the ESPs and the utilities, competition will be based on actual commodity procurement costs; between ESPs, competition will be based on the individual ESP's costs and services, not the utilities' costs. There will be no ESP migration to the service area of the utility with the largest PX credit. This also benefits the direct access customer, who will not be slighted because he or she resides in the service area of a utility with a low PX credit. ESPs will compete for the direct access customer based on the ESPs' costs and services, not on the basis of the residence of the customer.

From our experience in this RAP and the prior RAP, it is clear that the PX credit issue is complex enough to require a separate proceeding and that the time span between PX credit adjustments should be greater than one year. Therefore, the PX credit issue is severed from the RAP. The utilities shall file new applications to adjust the PX credit in 2003.

III. Reliability Must Run (RMR)

RMR generation is generation the Independent System Operator (ISO) determines is required to maintain a reliable transmission system, including generation to meet reliability criteria, load demand in constrained areas, and voltage and security support needs. Before the Commission initiated restructuring of the California electric industry with D.95-12-063, energy users paid the costs of those same transmission support functions. The vertically integrated utilities used generation resources as a substitute for certain transmission facilities because generation and transmission could be planned and operated on a coordinated basis. The costs of such uneconomic dispatch of generating units for transmission reliability purposes were reflected in increases in the costs of energy.

After restructuring, with generation participating in markets rather than being subjected to cost-based regulation, it was necessary to mitigate the market power generating units might otherwise exert when needed for reliability purposes. The ISO designated RMR units and executed FERC-approved RMR contracts with generators to provide the reliability services that are now necessary due to the restructuring of the electric service industry in California.

Under FERC-jurisdictional tariffs, the ISO bills the utility for the costs of RMR units in the utility's service area. The ISO's tariff requires the utility to pay RMR costs invoiced to it by the ISO -- "Each Responsible Utility shall pay the amount due under each Responsible invoice by the due date specified in the Responsible Utility invoice…." (ISO tariff § 5.2.7.)

The utility's recovery of the RMR invoices it receives are governed by the FERC-jurisdictional Transmission Owner (TO) Tariff which specifies that the RMR costs charged to the utility by the ISO are to be recovered from "End

Users": "Must-run contract costs payable by a utility that is a Participating TO pursuant to Section 5.2.7 of the ISO Tariff shall be recovered from End-Users located in the Service Area of that utility." (TO tariff § 15.) Under the TO tariff, the term Service Area is not defined. As of December 20, 1995, Edison provided electric service to retail end-use customers in its service territory, but it did not provide direct electric service to the retail customers inside areas served by municipal utilities. However, Edison provided transmission service to the municipal utilities.

Edison claims it is authorized by this Commission to fully recover from Edison's own retail customers the RMR costs billed by the ISO to participating transmission owners in two decisions - D.97-12-109 and D.98-04-019:

> The Commission should grant the petition to modify D.97-08-056 filed by Edison with regard to must-run costs to the extent it would account for the costs in the TRA for purposes of calculating "headroom."[7]

Edison currently allocates 100% of RMR costs to retail customers, even though both retail and wholesale customers benefit from system wide voltage support and the mitigation of thermal loading of transmission facilities resulting from RMR generating unit reliability. ORA recommends that Edison promptly file at FERC proposals to recover RMR costs from its wholesale customers and in the event it fails to file, ORA recommends that the Commission impute an

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[7] D.97-12-109, mimeo. p. 11, Conclusion of Law 3. See also D.98-04-019: "[PG&E], [Edison], and [SDG&E] are authorized to recover must-run payments made to the [ISO] and authorized by the [FERC] to the extent that these payments are recovered from the revenues collected by each utility during the transition period and as described herein." (D.98-04-019, mimeo. p. 5, Ordering Para. 1.)

allocation of RMR costs to wholesale customers by limiting the level of RMR costs recorded in the TRA.[8]

Prior to D.98-04-019, the Participating TOs (PTOs) had filed at FERC TO tariffs which included a section relating to the "Recovery of Must-Run Contract Cost." TO tariff § 15 states:

> "Must run contract costs payable by a utility that is a participating TO pursuant to Section 5.2.7 of the ISO Tariff shall be recovered from End Users located in the Service Area of that utility. Such utility shall file with the Commission and/or the appropriate Local Regulatory Authorit(ies) a mechanism for such cost recovery."

ORA argues that the plain text of TO tariff § 15 states that RMR costs will be recovered from end-users, but most importantly, it does not state that they will be exclusively or as Edison asserts "strictly" recovered from retail transmission customers. The TO tariff further establishes the concurrent jurisdiction of FERC and/or the CPUC to determine the mechanism for RMR attributable cost recovery. Given what the TO tariff does not say, the express language of the TO tariff and the PTO's voluntary election to seek recovery of RMR costs at the CPUC, ORA contends that it is baseless for Edison to claim that the CPUC does not have regulatory jurisdiction over the TO tariff when in fact the TO tariff enables the CPUC to establish a mechanism for RMR attributable cost recovery if the PTOs so avail themselves of CPUC jurisdiction.

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[8] PG&E currently allocates 100% of RMR costs to its retail customers. But it has acceded to ORA's recommendation and has filed at FERC to allocate a portion of those costs to wholesale customers. SDG&E has already made such a filing.

ORA believes Pub. Util. Code § 451 is applicable to this issue. Section 451 states that "[e]very unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful." ORA claims the exemption of wholesale transmission customers from paying a fair share of RMR costs results in retail transmission customers footing the entire RMR bill. Because retail customers are subsidizing wholesale customers, the present RMR cost recovery mechanism is unjust and unreasonable. In addition, Pub. Util. Code § 453 states that "[n]o public utility shall establish or maintain any unreasonable difference as to rates, charges, service, facilities, or in any other respect … between classes of service." ORA asserts that by not paying anything toward RMR costs, Edison's wholesale customers receive unduly discriminatory and preferential rate treatment contrary to the proscriptions of § 453. Similarly, §§ 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824(d) and 824(e), prohibit unjust and unreasonable rates and unduly discriminatory or preferential rates

ORA recommends that the Commission require Edison to immediately file proposals at FERC to recover a fair allocation of RMR costs to its wholesale transmission customers, to apply to the remainder of the utility's rate freeze period.[9] If Edison does not make such a filing, ORA recommends that the Commission should impute an allocation that represents a proxy for what a FERC-adopted RMR cost allocation may achieve. This imputed allocation would be used to limit the amount of RMR costs debited to the TRA for ultimate recovery from retail customers. Under ORA's recommendation the imputed

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[9] ORA originally made this recommendation for both Edison and PG&E, but because PG&E has made the request filing at FERC, ORA's recommendation is now limited to Edison. (See Appendix C.)

allocation would limit Edison's recovery of future RMR costs to 87% of the total paid to the ISO and be applicable for the remainder of Edison's rate freeze period.

Edison claims that ORA's recommendations were previously raised by ORA and rejected by the Commission in D.97-12-109, in A.96-12-019. Edison reminds us that in A.96-12-019, ORA argued before this Commission that,

> "The beneficiaries of must-run generation in Edison's transmission service area may include wholesale customers as well as retail customers, but recovery of the ISO's must-run billings through retail rates would place the entire burden of these costs on retail customers. The Commission should not accept this result without further analysis."

Edison responded that,

> "However, the FERC Transmission Owners (TO) Tariff states that these costs '. . . shall be recovered from end-users located in the Service Area of that utility . . . .' (Revised Pro Forma Transmission Owners Tariff Section 15, August 15, 1997.) Wholesale customers are not end-users and will therefore not pay these costs."

However, when we issued D.97-12-109 granting permission to recover RMR costs from retail customers, we did not explicitly address this issue. Therefore, there is no basis for citing this discussion as a precedent.

Edison argues that both FERC and the federal courts have recognized that rate filings at FERC are the utility's to make, and the state regulatory authority cannot legally order the utility to make a particular rate filing at FERC. (Western Mass. Electric Co., 23 FERC ¶61,025 (1983), affirmed Mass. Dept. of Pub. Util. V. U.S., 72 F.2d 886 (1st Cir. 1984).) In addition, Edison contends that because FERC has set the wholesale rate that the ISO charged to Edison, and because FERC has assigned 100% of such costs to Edison's retail customers, this Commission cannot legally conclude that the FERC-jurisdictional rate is unreasonable nor can it change the FERC-authorized allocation. Further, Edison maintains that the "imputed" allocation to wholesale customers and accompanying limit on costs recovered from retail customers proposed by ORA would result in a disallowance of FERC-jurisdictional costs. Thus, Edison asserts that a Commission decision implementing ORA's recommendation would violate the filed-rate doctrine established by the U.S. Supreme Court. (See Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 966 (1986).)

However, this Commission does have jurisdiction over the costs Edison can recover from retail ratepayers. We are not convinced that these issues have been fully explained or litigated at FERC. FERC does set the RMR rates which are then charged to Edison, but FERC did not decide the RMR rates Edison could charge to others. In fact, there are no FERC-filed rates for which Edison can invoke the filed rate doctrine. Edison recovers its RMR costs (i.e., the charges assessed to Edison by FERC-imposed rates) by filing for recovery at this Commission. Therefore, we have jurisdiction over the costs Edison can reasonably collect from retail ratepayers. We can impute the amount of revenue that Edison could seek to recover from its wholesale customers. (Rochester Gas & Electric Corp. v. Public Service Commission of State of New York, 754 F.2d 99 (2d Cir. 1985).)

After a careful review of the facts presented in this proceeding, we are of the opinion that to exempt wholesale customers from paying their fair share of RMR costs is to give them a free ride to avoid paying for benefits received. The ISO has determined that certain generating units require RMR designation in order to ensure the reliability of the transmission system in a utility's service territory. Yet, while RMR units benefit the entire transmission system (given the interconnected nature of the transmission system all transactions become mutually interdependent) the utilities charge retail customers 100% of those costs. In simple terms, wholesale customers get the benefits from RMR service for free, even though in the case of Edison, about 13% of Edison's total transmission service revenue is recovered from wholesale transmission services. This allocation is unjust and unreasonable. Edison has not justified, nor can it justify, this allocation. The amounts in question are significant. Edison's RMR charges in 1998 exceeded $115 million and in 1999 exceeded $142 million.

Because we did not address this issue in previous decisions, we will not retroactively impute a portion of RMR costs to wholesale customers, nor disallow this recovery through the TRA. However, we put Edison on notice that it will no longer be able to prospectively recover 100% of its RMR costs in the TRA. In its next RAP application, we direct Edison to discuss the steps it has taken at FERC to address this situation. In light of this warning, we will seriously consider a disallowance of RMR costs attributed to wholesale customers in the next RAP.

IV. Other Contested Issues

A. The Distribution Energy Charge

Consistent with Commission policy, Edison adjusts distribution rates by increasing each rate component (customer, demand, and energy charges) by the PBR Update Rule, unless that increase would result in a particular charge exceeding the rate level in effect on June 10, 1996, in violation of the rate freeze. In the event a particular charge would exceed its June 10, 1996 level, Edison calculates the dollar amount of the differential and converts that to a per-kilowatthour adder to its distribution energy charge. FEA objects to this approach and contends that such a differential should be recovered through increases to all of the remaining rate components, as it is done by PG&E.

Edison's methodology has already been adopted by the Commission, even though it differs from PG&E's methodology, and has been in use in designing Edison's rates during the transition period. (D.97-08-056, p. 46.) There is no reason for us to change this methodology at this time. Accordingly, we reject FEA's recommendation and continue to adopt Edison's methodology.

B. Low Emission Vehicle (LEV) Programs

Pursuant to D.99-06-058 in the 1998 RAP, Edison reported on the implementation of its LEV programs and associated costs during the record period. This report demonstrates that Edison's record period costs and activities are reasonable and within the guidelines of the Commission's LEV decision, D.95-11-035.

FEA recommends that Edison be ordered to include in its next RAP filings a comprehensive analysis of the LEV programs from the inception to the present. FEA contends that the current filings do not provide a sufficient basis to allow an informed judgment of the overall effectiveness of the programs. We believe FEA's contentions are misplaced. There is no need for such additional data to be included in the next RAP. An annual RAP addresses Edison's program activities and associated costs within the record period of that particular proceeding. The RAP is not the proceeding to address the overall effectiveness of the programs or the continuation of the LEV programs beyond the current authorized period, December 21, 1995 through December 31, 2001. In D.95-11-035, we specifically set forth the information that should be provided annually and biannually. We also specified that those reports should be submitted to the Commission Advisory and Compliance Division (now the Energy Division).

Since the issuance of D.95-11-035, Edison has provided a detailed report of its program activities in every annual LEV report. In addition, Edison has provided a detailed report which also includes program expenditures in every Energy Cost Adjustment Clause (ECAC) proceeding and RAP for the record period covered by the particular proceeding. In the aggregate, these overlapping reports provide a complete and very detailed picture of the LEV program activities. We have reviewed this data and have found it reasonable. ORA was able to review Edison's LEV program for the current record period and concluded that Edison's implementation of its LEV program and associated expenditures are within the guidelines set forth in D.95-11-035 and that the recorded costs are reasonable.

The sum of information from these sequential reports is more than sufficient to allow an informed judgment of the overall effectiveness of the LEV programs. Edison should not be burdened with any additional analysis or compilation of the data.

V. Stipulations

A. Jurisdictional Allocation Stipulation

FEA, ORA, TURN, and Edison resolved their differences regarding the jurisdictional allocation factor issues in this proceeding. The agreement is set forth in the Jurisdictional Allocation Stipulation (Appendix B). The parties state that this stipulation represents a reasonable compromise of the parties' positions. It also promotes an efficient and optimal use of the parties' and the Commission's resources, and fairly reflects Commission decisions which govern the issues that are being considered in this proceeding.

The Stipulation provides that:

- The effective balance in the Jurisdictional Allocation Memorandum Account (JAMA) on February 15, 2000, approximately $24.1 million, including interest, will be removed from the account and not be recovered from ratepayers.
- Amounts recorded in the JAMA between February 15, 2000 and the effective date of a decision authorizing the stipulation will be transferred to the TCBA, and the JAMA will be eliminated.
- Beginning on the effective date of the decision approving this stipulation. Edison will apply the Recorded Energy Jurisdictional Factor to all transition and other generation-related costs to determine amounts recorded in the TCBA, and the Independent System Operator Revenue, Power Exchange Revenue, Unavoidable Fuel Contract Costs, and Hydro Generation Memorandum Accounts, and all other generation-related memorandum accounts that will transfer to the TCBA.

The stipulation recognizes: (1) the generation-related nature of the costs; (2) the diminishing amount of wholesale service Edison provides since its last GRC due to the restructuring of California's electric industry and associated impact on the jurisdictional-based allocation of its costs; (3) the need for consistency with the Commission's previously adopted methodology for similar costs reviewed in Edison's ECAC proceedings; and (4) the need for consistency with the treatment of generation costs and market revenues recorded in the TCBA. The methodology is also consistent with the decision in the 1998 RAP, which adopted a 100% retail allocation factor for the PBR exclusions, nuclear decommissioning, and public purpose programs revenue requirements. Accordingly, the Jurisdictional Allocation Stipulation will be adopted.

B. RMR Cost Allocation Stipulation

PG&E, ORA, and Aglet have compromised their differences regarding the allocation of RMR costs between retail and wholesale customers. This stipulation is Appendix C. PG&E has agreed to file with FERC, on or before April 28, 2000, a mechanism to recover RMR costs that includes a fair allocation of such costs to wholesale customers and to request that the filing be effective within 61 days of the filing date. In turn, ORA and Aglet agree that PG&E's commitment to make a filing at FERC resolves their concerns expressed in this proceeding with regard to allocating RMR costs between wholesale and retail customers, and that the stipulation supersedes the recommendations contained in ORA's testimony. The stipulation is reasonable and will be approved.

VI. Uncontested Issues

Issues which are uncontested by the parties will not be discussed but are adopted in the Findings of Fact. We have reviewed these uncontested issues and are satisfied that the utilities' proposals are appropriate and reasonable.

VII. Motion of SDG&E to File Advice Letter

In this RAP, SDG&E has calculated the LRMC of providing commodity procurement service to be .003¢/kWh. SDG&E asserts that because it had already ended its rate freeze it is necessary to split the .003¢/kWh between a PX credit of .001¢/kWh (to benefit direct access customers only) and a PX charge of .002¢/kWh (to be charged to bundled commodity service customers only). The result is that direct access customers will benefit by the .003¢/kWh differential compared to the amount paid by bundled customers.

Because SDG&E is proposing that a PX charge of .002 ¢/kWh be included in the existing electric energy change on its customer bills, it contends that a slight and minor rate increase could result. Normally, a formal application to increase rates is required by Commission rules. However, the Commission's GO 96-A, in Section VI, allows a utility to avoid a formal application to increase rates where the rate increase is minor in nature. Specifically, the rules states in pertinent part: "In cases where the proposed increases are minor in nature, the Commission may accept a showing in the advice letter provided justification is fully set forth therein, without the necessity of a formal application." Therefore, SDG&E moves the Commission, should it agree with SDG&E's proposal for a PX charge, to allow SDG&E to implement the PX charge by filing an advice letter pursuant to GO 96-A.

TURN objects to granting SDG&E's motion on the ground that it seeks relief beyond the scope of this RAP.

We will deny the motion. GO 96-A provides for review by our Energy Division. As we understand SDG&E's motion, if we were to grant it, the Energy Division review would be omitted. Our order in this proceeding authorizes an advice letter filing to implement the .007 ¢/kWh credit. Should SDG&E require further relief by way of a minor increase in rates it may file under GO 96-A for review by the Energy Division.

VIII. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311(d) of the Public Utilities Code and Rule 77.7 of the Rules of Practice and Procedure. Comments were received from Edison, PG&E, SDG&E, ORA, ARM, TURN, Aglet, and the Coalition of California Utility Employees, the California Department of General Services (DGS), the California Farm Bureau, and the Bay Area Rapid Transit District (BART). The active parties merely reiterated their positions taken in briefs, which will be disregarded. (Rule 77.3.)

BART proposes that the PX credit be provided to all UDC customers who procure energy supplies from sources other than that of the utilities, in addition to Direct Access customers. This proposal is rejected because it has no evidentiary basis and because it presents new factual information, untested by cross-examination, which should not be included in comments. (Rule 77.3.) Similarly, DGS's comments do not focus on factual or legal error, and are disregarded.

Edison and PG&E complain that this decision does not provide for recovery of energy procurement costs. Consideration of revenue requirements for any cost category is beyond the scope of a RAP. SDG&E seeks minor rate relief in this proceeding regarding PX issues. That request is denied.

IX. Motion of SCE to Sever the PX Credit Issue

On November 29, 2000, SCE filed a Motion to sever the PX Credit Issue from the Commission's decision in this case, seeking removal of all discussion and consideration of the proposed adder to the PX Credit and deferral of a decision on this question until the Commission issues a decision in Phase I of SCE's recently filed Rate Stabilization Plan, A.00-11-038. SCE argues that the Commission will decide in A.00-11-038 issues that have a direct bearing on the PX credit adder.

We will deny SCE's Motion. The PX credit adder issue is squarely before us in this docket. There is no schedule for A.00-11-038 as of yet, and it is speculative when, if or how the Commission will act on SCE's request in that proceeding.

Findings of Fact

A. Power Exchange Credit Issues

1. D.99-06-058 (the 1998 RAP Decision) required that the LRMC of the utilities' energy procurement services be calculated so that it could be added to the PX credit.

2. LRMC is the change in cost associated with a small change in output, over a long enough time that all factors of production that are capable of varying can be changed.

3. Even when allowing all factors of production to change, some costs – like most energy procurement costs – do not vary unless a firm exits the market entirely and thus will not vary with a small change in output. Moreover, if a firm is prevented from leaving the market, certain costs – whether marginal or total – cannot be reduced at all. This requires a short-run marginal cost analysis. The UDCs have performed what they call a long-run marginal cost analysis. In our consideration of marginal costs we would consider the UDCs presentation as short run.

4. The utilities have demonstrated that if they were to procure less energy, the workload would not change, as they would still have to submit a bid for every hour of the day regardless of load, and still have the same number of settlement statements; thus, the same number of employees would have to do the same amount of work.

5. The methodology proposed by ARM consists of calculating total costs, then dividing by total sales. This methodology is an average cost methodology, not LRMC nor short-run marginal costs.

6. Because the costs associated with procuring energy do not vary directly with the amount of energy procured, an average cost methodology is not appropriate to determine marginal costs.

7. Many of the costs which ARM and ORA sought to attribute to energy procurement relate primarily to distribution and to the total number of retail customers served by the utilities' transmission and distribution system, not to the proportion of direct access service customers. Those costs do not vary when the utilities decrease the amount of energy they procure.

8. Adding or subtracting the procurement function for slightly more than 2% of customers from the utility's panoply of functions has a marginal cost of zero or so near to zero as to be de minimis.

9. The utilities are required by law to be the default provider of electric commodity service to all retail customers within their respective service territories.

10. The default service obligation distinguishes the utilities from ESPs and influences the calculation of the PX credit.

11. ESPs are not legally required to provide service to every potential customer and can choose to serve only those electric commodity customers with fairly constant usage (which can decrease the complexity of the bids and reduce costs) and exit the market, or any segment of the market, at any time they believe it has become unprofitable.

12. The utilities, by contrast, cannot refuse service to any customer and cannot exit a particular segment of the market.

13. The default service obligation benefits all customers in that it provides them with something akin to an insurance policy.

14. The default service obligation is not cost-free and all electricity customers should pay for it.

15. The default service obligation serves as a constraint on the utilities' ability to reduce their procurement costs to zero.

16. Because a utility must always stand ready to provide energy procurement service, the utility can never reduce its costs to zero because it cannot vacate the market.

17. The divisor for calculation of any PX credit adder must be the total kWh usage of all UDC customers, not just bundled service customers' usage.

18. Costs associated with processing customer bill settlements and billing and metering costs, as well as the processing of meter data to determine customer consumption, do not belong in the PX credit and should be excluded from the procurement marginal cost calculation.

19. ARM's proposed PX credit adder for Edison of .067¢ per kWh is flawed because it: (a) improperly allocates Edison's Energy Supply and Marketing costs to procurement; (b) improperly attributes 100% of Market Monitoring and Analysis costs to procurement; (c) improperly allocates CS&I costs according to the ratio of PX revenues to total revenues less CTC revenues; (d) includes an amount for working cash that exceeds the total working cash requirement approved for Edison in its last general rate case; (e) improperly allocates a portion of Edison's customer information system to the LRMC of energy procurement and (f) improperly allocates capital costs to the PX credit.

20. ORA's proposed PX credit adder for Edison of .040¢ per kWh is flawed in that it: (a) improperly allocates nearly 80% of Edison's Energy Supply and Marketing costs to procurement;(b) improperly attributes 100% of Market Monitoring and Analysis costs to procurement; (c) improperly allocates 100% of

certain of Edison's customer service and mass market customer representatives costs to procurement; and (d) improperly divides procurement costs by bundled service kWh, rather than total kWh.

21. PG&E surveyed and interviewed employees in its PX operations, Utility Electric Supply, PX/ISO Relations, Customer Services, Account Services, and Call Center departments.

22. Those surveys and interviews asked whether the costs to operate those departments would decrease if PG&E lost 10%, 50%, or 100% of its procurement customers. The surveys and interviews also asked if those departments would avoid any of their capital costs if PG&E lost 10%, 50% or 100% of its procurement customers.

23. Those surveys and interviews constitute a valid marginal cost study, whether considered long run or short run.

24. PG&E demonstrated that the costs to operate those departments do not vary in response to a 10%, 50%, or 100% decrease in procurement customers.

25. The costs to operate those departments also do not vary in response to a 10%, 50%, or 100% increase in procurement customers.

26. If PG&E exited the procurement business entirely, the PX Operations, PX/ISO Relations, and Utility Electric Supply departments would save $2.53 million.

27. The costs of the Customer Services, Account Services, and Call Center Operations departments would not change even if PG&E existed the procurement business entirely.

28. Customer service representatives and customer account managers do not perform procurement-related activities.

29. PG&E would have to maintain the same customer information systems to serve PG&E's distribution customers regardless of the number of customers taking procurement service from PG&E.

30. SDG&E performed a traditional marginal cost calculation. ARM and ORA did not.

31. The specific activities which SDG&E performs currently that would not be avoided totally if SDG&E lost all its distribution customers to direct access include Customer Account Manager activities, load bidding to the PX, calculating Schedule PX Charges, interfacing with PX and ISO, programming for commodity service, capital lease system, and advertising.

32. ARM relied upon various allocation schemes to estimate SDG&E's commodity procurement-related costs which schemes were not shown to have any correlation to the actual procurement-related costs incurred by SDG&E.

33. The references by ARM to "shopping credits" in other states is irrelevant to this proceeding.

34. Direct access customers should not pay for utility commodity procurement services. Those services must be unbundled from distribution service.

35. Edison has properly categorized the commodity procurement services that are capable of being unbundled.

36. Based on Edison's categories and costs, the appropriate PX credit is .007¢/kWh.

37. To prevent discrimination among utilities and among customer location, the PX credit should be a uniform .007¢/kWh for Edison, PG&E, and SDG&E.

B. RMR Issues

38. In D.97-12-109 and D.98-04-019 the utilities were authorized to record RMR payments made to the ISO in the TRA, to the extent that those payments

are recovered from the revenues collected by each utility during the transition period.

39. D.97-12-109 and D.98-04-019 both contemplated that the RMR recovery mechanism established therein would end at the end of the transition period.

40. In A.96-12-019 the Commission did not address the propriety of retail customers paying 100% of RMR payments made by Edison to the ISO.

41. No party disputed that the RMR cost entries and related refund entries in the TRA by the utilities were inaccurate or reflected any amounts other than what was paid by the utilities or received in refunds by the utilities.

42. The rates, terms, and conditions of the ISO tariff and the Transmission Owner TO tariff are under FERC's jurisdiction.

43. The rates, terms, and conditions of the contracts under which various generators provide RMR service to the ISO are under FERC's jurisdiction.

44. Under the ISO tariff, the ISO invoices the utilities for the costs of RMR units located in their service area.

45. Under the TO tariff, the utilities can file to recover RMR charges from customers located in their service area, pursuant to either a FERC mechanism or a CPUC mechanism.

46. Edison has never filed at FERC for a mechanism to recover RMR costs from any of its customers, therefore, Edison does not have filed-rates for these costs.

47. As part of their regular operations, PG&E and Edison deliver electricity over their own transmission lines to wholesale customers. During that process wholesale customers benefit from the transmission system reliability added by RMR units, in the same way that retail customers benefit.

48. Wholesale customers benefit from RMR units whose costs are billed by the ISO to PG&E and Edison, but pay nothing toward those costs.

49. To exempt wholesale customers from paying their fair share of RMR costs is to give them a free ride to avoid paying for benefits received.

50. The FERC has never decided the allocation of RMR costs between Edison's retail and wholesale customers.

C. Other Edison Contested Issues

51. Edison's methodology of adjusting the Distribution Energy Charge so that an increase in the other distribution rate components does not violate the rate freeze is reasonable and consistent with Commission policy.

52. The administration and cost information Edison submits annually in the RAP regarding its LEV programs is reasonable and consistent with D.95-11-035.

53. Edison appropriately extended its Special Contracts with Mobil Oil Company and Dow Chemical Company in accordance with Pub. Util. Code § 372, and there is no reason to require Edison to submit additional information supporting these contract extensions in its next RAP.

D. Stipulated Matters

54. The "Stipulation Among the Federal Executive Agencies, the Office of Ratepayer Advocates, The Utility Reform Network, and Southern California Edison Company Regarding Jurisdictional Allocation Issues in the 1999 Revenue Adjustment Proceeding (Application No. 99-08-022)" is a reasonable compromise of the parties' positions, an efficient and optimal use of the parties' and the Commission's resources, and consistent with Commission decisions, and should be adopted.

55. The stipulation among PG&E, ORA, and Aglet regarding RMR costs is a reasonable compromise of the parties' positions, an efficient and optimal use of the parties' and the Commission's resources, and consistent with Commission decisions, and should be adopted.

E. Uncontested Edison Issues

56. Edison should be permitted to update its forecast revenue requirements provided in Table II-1 of its 1999 RAP Report to reflect the October 31, 1999 recorded balances in all memorandum and balancing accounts and should include the impact of all Commission decisions issued through the effective date of a decision in this proceeding.

57. Edison's entries into its TRA should be based on the PBR Distribution Exclusions revenue requirement, Transmission revenue requirement, Nuclear Decommissioning revenue requirement, and Public Purpose Programs revenue requirements, adopted as of the date of this decision.

58. Edison's PBR Distribution Exclusions revenue requirement is comprised of the following amounts which should be included in its 2000 Distribution revenue requirement:

a) A Reduced Capital Recovery Amount and Incremental Return authorized revenue requirement of ($57.098) million.

b) A portion of the Streamlining Residual Account (SRA) balance associated with the Non-Utility Affiliate Credits in the amount of ($22.639) million.

c) The Hazardous Waste Balancing Account balance of $16.522 million.

d) The Demand-Side Management (DSM) Incentives authorized revenue requirement adopted as of the date of this decision.

e) A portion of the SRA balance associated with the DSM Incentives in the amount of $1.781 million.

f) The portion of the PBR Distribution Rate Performance Memorandum Account associated with Edison's PBR net revenue sharing for 1997, including interest through April 6, 2000, authorized pursuant to Resolution E-3656. The amount to be returned to ratepayers through the distribution rate component will be included in Edison's compliance advice letter to be submitted on or before May 6, 2000.

g) The balance of the Affiliate Transfer Fee Memorandum Account in the amount of ($0.703) million, pursuant to D.97-12-088. Edison received notification on March 16, 2000 that Advice Letter 1289-E, which establishes the ATF Memorandum Account, was approved.

59. Edison's Transmission revenue requirement is comprised of the Base Transmission revenue requirement adopted as of the date of this decision and the Transmission Revenue Balancing Account Adjustment amount of ($32.494) million, and is appropriate.

60. Edison's Nuclear Decommissioning revenue requirement of $44.097 million is comprised of the following amounts and is appropriate:

a) The Nuclear Decommissioning Trust Fund revenue requirement of $25.0 million.

b) The San Onofre Unit No. 1 Shutdown Operation & Maintenance currently authorized amount of $11.522 million.

c) The Department of Energy (DOE) Decontamination & Decommissioning (D&D) Fee in the amount of $4.611 million.

d) A portion of the SRA balance associated with the DOE D&D Fees in the amount of $0.464 million.

e) The Spent Nuclear Fuel Storage (SNFS) Fee in the amount of $3.057 million.

f) A portion of the SRA balance associated with the SNFS Fees in the amount of ($0.557 million).

61. Edison's Public Purpose Programs revenue requirement of $191.925 million is comprised of the following amounts and is appropriate:

a) DSM, Research Development and Demonstration (RD&D), and Renewable amounts of $90.0 million, $28.5 million, and $49.5 million, respectively, as mandated by AB 1890.

b) The currently authorized amount of $7.360 million associated with Low Income Energy Efficiency (LIEE) Programs.

c) The currently authorized amount of $0.958 million associated with the administration of California Alternate Rates For Energy (CARE) programs.

d) The currently authorized amount of $1.214 million for RD&D programs administered by Edison.

e) The RD&D Royalties Memorandum Account balance in the amount of $1.705 million.

f) The Electric Vehicle Balancing Account balance in the amount of $9.427 million.

g) The Electric Vehicle Memorandum Account balance in the amount of $0.758 million.

h) A portion of the SRA balance associated with Intervenor Compensation payments in the amount of $0.837 million.

i) Franchise fees associated with the above listed Public Purpose Programs in the amount of $2.153 million.

62. The 1999 sales forecast proposed by Edison should be used to update the nongeneration Equal Percent of Marginal Cost (EPMC) factors utilized in allocating the PBR Exclusions and to convert those allocated revenues to a cents-per-kWh rate.

63. In the event that Edison's cost of capital Trigger Mechanism results in a cost of capital change, the resulting change in the Distribution revenue requirement calculated on a 1996 basis should be allocated to each customer class by their respective 1996 nongeneration EPMC percentages.

64. Edison's CARE surcharge amount of $0.00079 per kWh should be included in the Public Purpose Program charge.

65. Edison's proposed 2000 retail sales forecast of 79,470 GWh should be used to calculate the PBR Exclusions, Nuclear Decommissioning, and Public Purpose Programs rate levels.

66. Edison's Optional Pricing Adjustment Clause Balancing Account balance should be transferred to its TRA once the Commission reviews the 1998 Flexible Pricing Options Annual Report and determines that the shareholder contributions have been correctly calculated.

67. Edison should eliminate the following accounts as of the effective date of this decision:

a) Deemed Fossil Inventory Memorandum Account.

b) Disputed Arizona Property Memorandum Account.

c) Edison Pipeline and Terminal Company Tracking Account.

68. Edison's ISO/PX Implementation Delay Memorandum Account should be eliminated upon authorization of Edison's proposed disposition of any remaining balance pursuant to a Commission decision in Edison's 1999 Annual Transition Cost Proceeding, A.99-09-013.

69. Edison should eliminate the following balancing and memorandum accounts upon authorization of Edison's proposed disposition of any remaining

balances pursuant to a Commission decision in Edison's Direct Access Service Fee application, A.99-06-040:

a) Direct Access Discretionary Service Costs Memorandum Account.

b) Industry Restructuring Memorandum Account.

70. Edison should eliminate the following balancing and memorandum accounts upon authorization of Edison's proposed disposition of any remaining balances in this proceeding.

a) Electric Magnetic Field Balancing and Memorandum Account.

b) Jurisdictional Allocation Memorandum Account.

c) Women, Minorities & Disabled Veterans Memorandum Account.

71. Edison should be authorized to modify the Rate Group Tracking Memorandum Account to include the Trust Transfer Amounts and an imputed 10 percent rate reduction revenue amounts in the Rate Group CTC Revenue Memorandum sub-account each month.

72. Edison should be authorized to retain all of its existing balancing and memorandum accounts not addressed in these findings of fact.

73. Edison should be authorized to transfer the $1.069 million generation-related balance in the Catastrophic Event Memorandum Account to its TRA on the effective date of the decision in this proceeding.

74. On the effective date of this decision, Edison should be authorized to transfer residual balances recorded in the following balancing and memorandum accounts to its TRA, and adjust the appropriate revenue requirement in the

operation of its TRA to ensure that the residual CTC revenue is determined correctly without having to adjust rate levels:

a) CARE Adjustment Account.

b) EMF Balancing and Memorandum Account.

c) Catastrophic Event Memorandum Account.

d) RD&D Balancing Account (1995 GRC Unspent Balance portion only).

e) Women, Minorities & Disabled Veterans Memorandum Account.

75. Edison's Administration of its LEV Program and associated costs is reasonable for the May 1, 1998 through April 30, 1999 Record Period.

76. As of the effective date of D.99-09-070, adopting Edison's Gross Revenue Sharing Mechanism, all Other Operating Revenue (OOR) generated from Edison's LEV Program activities from September 16, 1999 forward will be subject to treatment under the adopted mechanism.

77. For OOR generated from Edison's LEV Program activities prior to September 16, 1999, Edison should credit back the OOR amounts to Edison's Electric Vehicle Adjustment Clause Balancing Account.

78. Edison's administration of its Self-Generation Deferral Rate Contracts during the Record Period is reasonable.

F. PG&E Findings

79. PG&E's administration of special electric contracts for the record period ending December 31, 1998, was reasonable.

80. PG&E's total costs recorded in the EVBA do not exceed the allocated budget under D.95-11-035.

81. PG&E files annual reports with the Commission providing detailed information on its LEV program, including accomplishments, projects, and expenditures.

82. PG&E's 1998 costs for its LEV program are reasonable.

83. It is not necessary to perform a review of PG&E's LEV programs from inception to the present.

84. PG&E proposed retention of six remaining IRMA subaccounts in its RAP application because the Commission had not yet specifically authorized PG&E to record unanticipated restructuring implementation costs PG&E incurred in 1999 in the Electric Restructuring Costs Account (ERCA).

85. In Resolution E-3648, the Commission authorized PG&E to record these unanticipated restructuring costs in the ERCA.

86. PG&E should address the six subaccounts of the IRMA in their next RAP application.

87. PG&E allocates performance-based ratemaking exclusion items such as the EVBA, the HSM, and SRA using the non-generation EPMC methodology.

88. PG&E's proposal to amortize the balances in the EVBA, the HSM and the SRA, by establishing rate components for these items on an equal ¢/kWh basis complies with Commission ratemaking requirements and is uncontested.

89. For the record period June 1998 through June 1999, PG&E correctly transferred all residual CTC revenue from the TRA to the TCBA.

90. PG&E's incorporation of real-time post settlement adjustments and block forward market costs into the PX credit calculation as required by Resolution E-3618 is reasonable.

91. PG&E's special electric contracts and entries to the EVBA are reasonable.

92. PG&E's proposals with regard to elimination of memorandum and balancing accounts are reasonable.

93. PG&E's entries in the TRA for the June 1998 through June 1999 periods are reasonable.

94. The consolidated and unbundled revenue requirements adopted by the Commission in other proceedings for entry into the TRA are reasonable.

95. PG&E's revenue allocation and rate design proposals are reasonable.

96. PG&E's request to consolidate the revenue requirements authorized in pending proceedings impacting test year 2000, including the Annual Earnings Assessment Proceeding (A.99-05-007), the Cost of Capital proceeding (A.99-11-003), the § 368(e) proceeding (A.99-03-039), and the Catastrophic Event Memorandum Account proceeding (A.99-01-011) is reasonable.

97. PG&E's request to update the illustrative 2000 revenue requirements presented in this proceeding to include the balancing and memorandum accounts' latest recorded balances for recovery in the TRA is reasonable.

Conclusions of Law

1. This Commission cannot legally order Edison to make a Federal Power Act Section 205 filing at FERC under Mass. Dept. of Pub. Util. v. U.S., 729 F.2d 886 (1st Cir. 1984). However, this Commission has jurisdiction to decide how much of Edison's RMR costs Edison may recover from its distribution customers.

2. The filed rate doctrine does not apply in this case because Edison elected to file for a mechanism to recover if its RMR costs at this Commission rather than at FERC.

3. Aglet's recommendation that the Commission allocate a percentage of total RMR costs incurred by Edison since April 1998 to wholesale customers and thereby disallow a portion of the RMR costs already paid to the ISO is denied.

4. Edison is put on notice that it will not be able to prospectively recover 100% of its RMR costs in its TRA.

5. SDG&E's request to segment the PX credit between a credit and a charge is denied.

6. SDG&E's request to increase rates is denied.

7. The stipulations set forth in Appendices B and C are adopted.

8. The uncontested issues described in the Findings of Fact are reasonable and are adopted.

9. The PX credit issue is severed from the RAP.

10. The utility distribution companies shall file their next PX credit adjustment proceeding September 2003.

O R D E R

IT IS ORDERED that:

1. The Power Exchange credit adder to be credited to the electricity bill of each direct access customer is .007 cents per kilowatt-hour. This adder shall be credited in addition to the credit that offsets the wholesale procurement of energy for bundled customers. This credit is applicable to customers of Southern California Edison Company (Edison), Pacific Gas and Electric Company, and San Diego Gas & Electric Company (the utility distribution companies).

2. Within 15 days after the effective date of this order the utility distribution companies shall file tariffs implementing Ordering Paragraph 1, and implementing all other provisions authorized in this decision.

3. In Edison's next RAP application, Edison shall delineate the efforts it has undertaken at the Federal Energy Regulatory Commission to recover a fair share of Reliability Must-Run Costs from its wholesale customers..

4. The utility distribution companies shall file their next Revenue Adjustment Proceeding (RAP) within 60 days after the effective date of this order.

5. The PX credit issue is severed from the RAP.

6. The utility distribution companies shall file their next PX credit application in September 2003.

7. Application (A.) 99-08-022, A.99-08-023, and A.99-08-026 are closed.

This order is effective today.

Dated January 4, 2001, at San Francisco, California.

LORETTA M. LYNCH
President
CARL W. WOOD
JOHN R. STEVENS
Commissioners

I will file a dissent.

/s/ RICHARD A. BILAS
Commissioner

I dissent.

/s/ HENRY M. DUQUE
Commissioner

Commissioner Bilas, dissenting.

Former Commissioner Neeper, in his alternate to this decision espoused correct economic theory in his analysis of the bulkiness or lumpiness of the long run marginal costs we use to arrive at a PX credit adder. Being a former professor of economics who has authored a textbook with a discussion of bulkiness, I could appreciate that the arguments advanced by the retail marketeers were not only pro-competitive, but also reflected good economic theory. The decision voted out by the majority today is neither pro-competitive nor economically sound. We cannot keep stymieing retail competition if we are seeking rational markets. ESPs have left the state in droves. More and more direct access customers have been returned to the UDCs. This only exacerbates their procurement financing problem. The alternate as modified by my alternate pages that specified utility specific PX credit adders would have encouraged ESPs to stay in California. These days they need all the encouragement we can give them. While on the surface an average PX credit across all service territories would appear to equally incent ESPs statewide, as an economist I believe in matching marginal revenues to marginal costs. The low uniform credit adopted by the majority fails to do so. Just as the proposed alternate order on a stand alone basis was, it is not reflective of rate differences among the utilities. Today's decision will be problematic in future long run marginal cost calculations in other unbundling proceedings.

I reiterate that the decision voted out today does nothing towards increasing a retail demand component relative to wholesale markets. I have long been warning my colleagues about the dangers of lack of a demand component to balance out the supply end of the market equation in California. Commissioner Neeper's alternate as modified by my alternate pages would have assisted the Commission to move forward in this area as our Market Surveillance advisors insist will help correct our market dysfunction problems. We must continue to support direct access as part of our reform of restructuring. Instead, today's decision is a step backward for direct access.

Finally, I believe it is important to foster direct access because many retail switches occur because of green power. As a former member of the California Energy Commission, I recognize the importance of renewal resources to the state of California and its citizenry. An opportunity to encourage marketing of green power has been lost.

Therefore, I dissent from the majority's decision.

/s/ RICHARD A. BILAS
RICHARD A. BILAS
Commissioner

San Francisco, California
January 4, 2001

(SEE CPUC FORMAL FILES FOR APPENDICES A-C)