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Decision 99-06-058 6/10/99

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of The Revenue Adjustment Proceeding (RAP) application of San Diego Gas and Electric Company (U 902-E) for approval of 1) Consolidated changes in 1999 authorized revenue and revised rate components; 2) the CTC rate component and associated headroom calculations; 3) RGTCOMA balances; 4) PX credit computations; 5) disposition of various balancing/memorandum accounts; and 6) electric revenue allocation and rate design changes,	Application 98-07-006 (Filed July 1, 1998)
Application of Pacific Gas and Electric Company for verification, consolidation and approval of costs and revenues in the transition revenue account,	Application 98-07-003 (Filed July 1, 1998)
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 and dispose of amounts in various balancing and memorandum accounts; 4) verify regulatory balances transferred to the transition cost balancing account on January 1, 1998; and 5) propose rate recovery for Santa Catalina Island diesel fuel costs.	Application 98-07-026 (Filed July 1, 1998)

(See Appendix A for List of Appearances.)

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OPINION

Summary

This decision resolves issues raised in the first "revenue allocation proceeding" (RAP) for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas and Electric Company (SDG&E). The purpose of the proceeding is to review entries to electric utility accounts which have been established to effect the provisions of Assembly Bill (AB) 1890 and previous Commission orders in pursuit of promoting competition in electric generation markets.

I. Background

In July 1998, PG&E, Edison, and SDG&E filed these applications pursuant to Decision (D.) 96-12-077 and the Coordinating Commissioner's Ruling dated March 14, 1998.

D.96-12-077 referred to the need for this proceeding as follows:

> "To streamline our proceedings while retaining our ability to carry out our remaining ratemaking obligations, we will establish a new annual proceeding, the Revenue Allocation Proceeding (RAP), to consolidate pending changes in authorized revenues and to track revenues collected at frozen rate levels. Authorized levels of revenue requirement will be established in other proceedings can be consolidated in the RAP."

D.97-10-057 provided further guidance regarding accounting during the rate freeze period and approved, among other things, a "transition revenue account (TRA)" for PG&E, which Edison and SDG&E later implemented as well. TRA tracks authorized costs and revenues for the purpose of calculating "headroom," that is, the revenues available to the utilities during the rate freeze period for recovery of costs associated with stranded generation investments. The entries into these accounts are subjects of this proceeding. The Assigned

Commissioner Ruling dated March 14, 1998 issued in Rulemaking (R.) 94-04-031 further specified that these applications would consider revenue allocation, rate design, the accuracy of the Power Exchange (PX) credit and other accounting issues.

Several parties filed protests to the utilities' applications, and the Commission held a prehearing conference to address related procedural matters. By ruling dated September 16, 1998, the Commission further specified the scope of this proceeding to include:

> Allocation of transition costs between customer groups;
>
> Allocation of Pub. Util. Code Section 376 costs between customer groups;
>
> The accounting treatment of Edison's fuel costs for service to Santa Catalina Island;
>
> The accuracy of PX calculations and PX credit components performed by the utilities; and
>
> The elimination or modification of balancing accounts and memorandum accounts.

Subsequently, the assigned Commissioner issued a ruling directing the applicants to file supplemental testimony addressing post-real time settlement costs, the California Alternative Rates for Energy (CARE) surcharge, and discount and residential minimum charges.

On December 18, 1998, the Office of Ratepayer Advocates (ORA) and PG&E filed a stipulation that would resolve a number of controversies between them. On December 22, 1998, ORA and Edison filed a stipulation, and ORA and SDG&E filed a stipulation. No party has opposed any of these three stipulations.

On January 8, 1999, applicant utilities Enron Corporation (Enron) and Western Power Trading Forum (WPTF) filed stipulations regarding certain elements of the PX credit calculation.

Numerous parties have been active in this proceeding, among them, ORA, The Utility Reform Network (TURN), the California Large Energy Consumers Association, the California Manufacturers Association, the California Industrial Users and the Energy Producers and Users Coalition (jointly, CLECA), California Department of General Services (DGS), Bay Area Rapid Transit District (BART), Enron, California Farm Bureau Federation (Farm Bureau), the United States Department of Navy representing all Federal Executive Agencies (FEA), Commonwealth Energy Corporation (Commonwealth), and WPTF.

The Commission held seven days of hearings in this proceeding during December 1998, one of which was attended by the assigned Commissioner. This order is issued within the eighteen-month period allotted for ratesetting proceedings by Senate Bill 960.

II. Cost Allocation and Rate Design

A. Allocation of Direct Access Implementation Costs

One objective of this proceeding is to allocate between customer groups the costs of implementing direct access or "restructuring" costs. These restructuring costs are addressed in Pub. Util. Code § 376 applications. The utilities have filed separate applications asking the Commission to find eligible costs that would receive special ratemaking treatment under § 376.[1] The utilities

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[1] Section 376 does not authorize recovery of restructuring implementation costs, but permits the utilities to recover uneconomic generation-related costs beyond December 31, 2001 to the extent the opportunity to recover these costs is reduced by Federal Energy Regulatory Commission (FERC)- or Commission-authorized recovery of unreimbursed implementation costs incurred by the utilities. (See D.97-12-042 at 4.)

have incurred costs for the following activities related to direct access: hourly interval meter installation and reading costs, billing system modifications, consumer education and electric education trust activities, customer information release to competitors, and PX start-up and development (or PX "initial charges").

Edison proposes recovering implementation costs through the TRA mechanism, arguing that such accounting treatment will obviate the need for an explicit cost allocation in this proceeding.[2] It would defer the matter to its post-transition period ratemaking application, which it filed on January 15, 1999.

PG&E proposes to enter pre-1999 restructuring costs into the TRA once and for all and to "functionalize" post-1998 restructuring costs into distribution, generation and transmission components for future recovery.

If the Commission allocates the costs in this proceeding, Edison, PG&E and SDG&E propose allocating these costs using Equal Percentage of Marginal Cost (EPMC) or a method referred to as the "system average percentage" (SAP) method. They believe this allocation is most consistent with the Commission's existing methods for allocating fixed costs. Edison observes that the Commission has endorsed EPMC because it most closely reflects the cost of service and promotes pricing which improves system efficiency.

ORA objects to Edison's proposal to defer the determination of appropriate cost allocation. It would have the Commission establish an accounting within the TRA mechanism that would track how various customer groups have contributed toward the payoff of transition costs. According to

[2] The existing method of debiting the TRA allocates the costs of implementation in proportion to the customer's share of the competition transition charge (CTC) or "headroom."

ORA, the Commission could then use this information in determining the mechanics of ending the rate freeze for each customer class.

ORA and TURN propose that the utilities allocate implementation costs on an "equal cents per kilowatt-hour"(kWh) basis.[3] Under this allocation method, each customer would pay a share of implementation costs according to the quantity of electricity used. TURN comments that such costs do not vary with system usage and therefore are not necessarily good candidates for the EPMC allocation the Commission has normally used. It compares implementation costs with those of the CARE program and the Commission's treatment of those costs. As TURN observes, D.96-04-050 allocated CARE costs using an equal-cents per kWh method on the basis that the CARE program was unrelated to energy consumption and that equity concerns should be the primary basis for determining appropriate cost allocation. In pursuing its argument for an equitable allocation of direct access implementation costs, ORA and TURN observe that utility customers are not benefiting equally from direct access. ORA demonstrates that industrial and large commercial customers purchase 95% of electricity sold in the direct access program. ORA observes that even under its allocation proposal, small customers would still pay for 34% of restructuring costs, even though they have consumed only 5% of the energy sold through the direct access program.

TURN observes that § 367(e)(1) limits shifting the burden of stranded generation costs between customer classes but does not affect the Commission's discretion to allocate implementation costs because the Commission has not heretofore allocated such costs.

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[3] TURN also proposed using generation EPMC to allocate the costs as an alternative but states a preference for ORA's proposed allocation method.

Enron, FEA, CLECA, DGS and Edison object to the TURN and ORA proposed method of allocation. Some observe that using an equal percent of kWh allocation is the equivalent of a "functionalization" of the costs, that is, a determination that the costs are associated with, in this case, generation. FEA points to uncontested utility testimony that demonstrates restructuring costs are related primarily to customer service and transmission. Enron, FEA and Edison observe that restructuring costs are fixed and therefore do not vary according to the amount of energy consumed. The costs should therefore not be recovered on the basis of energy consumption levels, as the ORA and TURN method would require. FEA believes the proposals of TURN and ORA violate the prohibition on cost shifting presented in AB 1890. Enron argues that functionalization is appropriately the topic of the § 376 proceeding, A.98-05-004, et al.

Discussion. We share the concern of TURN and ORA that using existing methods to allocate restructuring costs could be unfair to small customers. Large customers have been and are likely to be the primary beneficiaries of direct access for the foreseeable future. Existing cost allocation methods would not correspond to the distribution of benefits. Under existing methods, small customers in fact assume a share of costs that is wildly disproportionate to the benefits they have realized. Even the cost allocation methods ORA and TURN propose allocate considerably more restructuring costs to small customers than those customers have imposed on the system.

Our policy has consistently been that costs should be allocated to those customers who impose them. The methods the utilities propose for allocating restructuring costs do not accomplish that objective. Unfortunately, existing law limits our discretion to allocate implementation costs in this instance. As a preliminary matter, we do not agree with TURN that such costs are exempt from the cost shifting provisions of § 367 because they are "new." The fact that the costs have been incurred since the passage of AB 1890 does not exempt them from cost shifting provisions of the act. Section 367(e)(1) requires that transition costs be allocated "in substantially the same proportion as similar costs are recovered as of June 10, 1996..." The statute does not distinguish existing costs from new costs. However, § 367 applies only to transition costs. Restructuring implementation costs are not transition costs as defined by §§ 367 and 840. As the Commission found in D.97-12-042, restructuring costs are those costs which may be recovered pursuant to § 376 and only to the extent they displace recovery of transition costs and extend the period for recovery of transition costs.

Although § 367 does not identify restructuring costs as among those which must be allocated as they have been in the past, a departure from past practice is probably not permissible under the statute. As PG&E points out, changing the allocation of one type of cost affects the relative burden of the CTC among customer groups, indirectly changing the cost allocation in effect June 10, 1996 and in contravention of § 367. We are therefore constrained from adopting new cost allocations for restructuring costs.

For restructuring costs incurred through 1998, the utilities shall allocate restructuring costs using the total EPMC or system average percentage method through the transition period. We will determine treatment of post-transition period costs in the utilities' associated applications, as Edison proposes. In the interim, the utilities shall add a new column to the utilities' Revenue Sub-account in the Rate Group Transition Cost Obligation Memorandum Account, as ORA proposes, to track the costs allocated to each customer group. This accounting will permit flexibility in determining how to end the transition period for customer groups. These costs will not be included as separate rate components on customer bills because they would create customer confusion without a transparent corresponding benefit.

B. Allocation of Transition Costs

D.97-06-060 requires the utilities to track transition costs and payments by rate group.[4] The utilities include these costs in accounts we have titled Rate Group Tracking Memorandum Accounts (RGTMA). The utilities have so far allocated the costs between rate groups by the EPMC method.

ORA argues that the Commission has not yet determined whether the costs should be allocated based on EPMC, which reflects total marginal costs components, or marginal costs based on generation only. ORA proposes that allocation be based on an equal percentage of generation marginal costs (EPGMC) factor on the basis that it would most fairly and efficiently recognize the allocation of generation usage between customer groups.

The applicants, Farm Bureau, FEA, and CLECA, object to ORA's proposal to allocate transition costs based on generation marginal cost. These parties argue that ORA's proposal would constitute cost shifting between customer groups in violation of AB 1890 and contrary to previous Commission decisions. They observe that ORA's own analysis demonstrates that its proposal would reduce small customers' rates by millions of dollars and increase them for larger customers by a corresponding amount.

Discussion. Commission decisions have not been entirely clear on the subject of precisely how to allocate transition costs between customers. Early decisions stated that cost-shifting should be avoided. The Commission Preferred Policy Decision states:

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[4] Transition costs are those which, pursuant to § 367, are generation-related costs which the utilities would be unable to recover in an unregulated generation market at prevailing market rates.

> "Transition costs will be allocated to all customer classes using an equal percentage of marginal cost (EPMC) methodology, unless specific circumstances justify a different approach. Marginal cost pricing for electric services using the EPMC methodology is well established, and using this approach for the allocation of transition costs ensures a fair allocation among all customer classes and prevents inter- and intraclass cost-shifting. Using this approach also preserves the cost allocation that we have previously reviewed and approved " (D.95-12-063, p.142).

Although D.95-12-063 does not specify whether the EPMC allocation methodology is a factor of total EPMC or generation only, it refers to a "well established" methodology. The only well-established methodology in our ratemaking proceedings is that which the parties refer to as total EPMC.

Subsequently, D.96-12-077 reiterated Commission policy regarding the allocation of transition costs and cost shifting:

> "Since rates for each customer class are frozen, revenues will be allocated essentially as they were on June 10. Preserving the June 10 revenue allocation corresponds on the revenue side to § 367 (e)(1)'s directive that transition costs are to be allocated among the various customer classes, rate schedules, and tariff options, and recovered from these categories 'in substantially the same proportion' as similar costs were recovered in retail rates on June 10, 1996."(D.96-12-077, pp. 12-13).

Later, we hedged the issue to some extent prior to considering the impact of AB 1890 in the context of final allocations. D.97-12-039 found that we would use EPMC to allocate costs "unless specific circumstances justify a different approach." The order reinforces the Commission's established position by citing § 367(e)(1) but suggests the resolution of the matter was not necessarily final. Finding of Fact 9 states: "The transition cost allocation factors may be re-evaluated in the First Revenue Adjustment Proceeding."

Although our decision may have suggested an intent to consider departures from the traditional EPMC methodology, we find that AB 1890 prohibits such action. During the transition period, the Commission may not order the utilities to shift costs between customer classes. Specifically, Pub. Util. Code § 367(e)(1) mandates that transition costs:

> "Be allocated among the various classes or customers, rate schedules, and tariff options to ensure that costs are recovered from these classes, rate schedules, contract rates, and tariff options, including self-generation deferral, interruptible, and standby rate options in substantially the same proportion as similar costs are recovered as of June 10, 1996."

No party disputes that the cost methodology the utilities already have in place is based on total EPMC. No party suggests that the EPMC methodology is not the one used to allocate costs as of June 10, 1996, consistent with past ratemaking decisions. The allocation method ORA proposes would depart from established practice and constitutes unlawful cost-shifting, as the utilities and other parties argue. We reject ORA's proposal to apply a generation-only EPMC cost methodology for transition costs.

C. Allocation of SDG&E's Transmission and Distribution Revenue Requirements

ORA originally opposed the method used by SDG&E to allocate transmission and distribution revenue requirements, arguing that it contravened the Commission's order in D.97-08-056. Following discussions between ORA and SDG&E, the parties resolved their differences. SDG&E agrees to allocate these revenue requirements as follows: combining the FERC approved transmission revenue requirement and the Commission-approved distribution revenue requirement, allocating to customer classes using the individual class transmission and distribution marginal cost and calculating the final distribution revenue requirement by subtracting transmission revenues from the combined revenue requirement. This method of allocation is not opposed by any party and is consistent with D.97-08-056. We therefore adopt it here.

D. Distribution Revenue Requirement Allocation to Schedule E-20T

BART proposes that it should not pay distribution costs because the distribution marginal cost revenues associated with its rate schedule, E-20T, is zero. According to BART, PG&E's proposal to allocate distribution costs to schedule E-20T violates Commission policy with regard to rates reflecting EPMC and costs, thereby creating inappropriate price signals for customers like BART.

PG&E opposes BART's proposal, arguing that the distribution revenue requirement includes not only the cost of distribution but also the costs of metering, customer services and billing activities, services which BART continues to receive. PG&E observes that its stipulation with ORA on cost allocation matters reduces BART's distribution revenue requirement by 40%, which according to PG&E increases the distribution allocation to residential rates by $5.7 million. To go further, according to PG&E, would provide an unlawful and unfair advantage over other customers.

We deny BART's request to exempt schedule E-20T customers from distribution costs. As PG&E observes, doing so allocates costs on a "functional" basis, that is, based only on transmission and customer costs. We have rejected allocating EPMC on a functional basis for other customer groups, finding that it would violate provisions in AB 1890 which preclude cost allocation shifts during the rate freeze period.

E. Stipulation Between ORA and SDG&E

On December 22, 1998, SDG&E and ORA filed a stipulation in this proceeding with respect to several contested issues. The stipulation provides for the following:

1. For small and residential customers, Public Purpose Program (PPP) and nuclear decommissioning costs are allocated using the SAP method and the frozen rate levels without adjustment for the 10% rate reduction;

2. SDG&E will charge $4,600 to new customers on Schedules A-V1, A-V2, and A-V3 for the cost of signaling equipment used to measure peak-pricing periods;

3. Transmission, generation, nuclear decommissioning, and PPP components of the $5.10 residential minimum bill will be calculated based on average minimum bill usage.

4. Non-generation revenue requirement should be updated after December 31, 1998 to reflect the impact of Commission decisions issued after July 1, 1998, provided to all parties to this proceeding and incorporated in the decision issued herein; and

5. Certain balancing accounts and memorandum accounts will be eliminated as set forth in ORA's revised Table 2-1 with the exception that ORA and SDG&E remain at odds with regard to netting the balances in various accounts.

ORA and SDG&E propose that their stipulation is reasonable and consistent with the law. No party opposes it. We adopt it as a reasonable resolution of outstanding disputes that is consistent with our policies and the law.

F. Stipulation Between Edison and ORA

ORA and Edison filed a stipulation on December 22, 1998 resolving several issues as follows:

The CARE Discount and the CARE Surcharge. ORA originally recommended that the CARE discount be allocated to distribution rates. Edison proposed that the CARE surcharge and discount should continue to be allocated to the PPP charge. The stipulations require applicants to allocate the CARE discounts to distribution rates and to allocate the CARE surcharge to the PPP charge. As a result, the PPP charge would be reduced by an amount equal to the CARE surcharge for customers exempt from the surcharge.

Allocation of PPP and Nuclear Decommissioning Revenue Requirements. Under the stipulation, Edison would use the SAP method to allocate PPP and nuclear decommissioning revenue requirements between customers to adjust June 10, 1996 rate levels, without adjusting for the 10% rate reduction applicable to residential and small commercial customers.

Balancing and Memorandum Accounts. The stipulation provides that Edison would eliminate various balancing and memorandum accounts which are no longer useful, as set forth in ORA's revised Table II-1. It provides that those memorandum and balancing accounts reflecting generation costs which were or will be transferred to the Transition Cost on Balancing Account (TCBA) will be addressed in the ATCP. Upon completion of that review, the Commission would consider whether to eliminate or retain various accounts in the subsequent RAP.

Updated Revenue Requirements. The stipulation provides that the revenue requirements to be addressed in this proceeding should be updated after December 31, 1998 to reflect any Commission decisions issued and to account for final recorded balances.

Low Emission Vehicle Costs and Special Contracts. The stipulation provides that the costs associated with low emission vehicles and special contracts should be reviewed in the next RAP proceeding.

Costs Incurred by Edison to Serve Santa Catalina Island. ORA and Edison agree that Edison should be permitted to recover Santa Catalina fuel costs through the TRA. They also agree that the commodity cost should be reflected on Santa Catalina customers' bills at a rate of $.0685 per kWh for 1999 for informational purposes.

Discussion. The stipulation filed by ORA and Edison is reasonable and consistent with the law and the record, with one exception. The treatment of Santa Catalina fuel costs is not lawful. Edison and ORA agree that Edison should be permitted to recover Santa Catalina Island diesel fuel costs through the TRA mechanism. In its testimony, Edison demonstrated that it has not recovered its Santa Catalina diesel fuel expenses because the TRA does not currently account for Santa Catalina fuel costs. This occurs because the PX and Independent System Operator (ISO) do not provide power services to Santa Catalina as a result of its geographic isolation. The revenues available to offset stranded costs ("headroom") is therefore larger than it would otherwise be because Santa Catalina's fuel costs are not deducted from the total monthly billed revenues. Edison originally proposed to recover Santa Catalina diesel fuel costs in the TRA mechanism as a separate item. ORA did not address the matter in testimony but subsequently agreed to Edison's proposal in the stipulation filed on December 22, 1998.

Notwithstanding ORA's ultimate concurrence with Edison's proposal, the proposal is unlawful. Pub. Util. Code § 367(c) states that certain costs of fossil plant operation may be recovered only through the ISO or PX:

> "All going forward costs of fossil plant operation, including operation and maintenance, administration and general, fuel and fuel transportation costs, shall be recovered solely from independent Power Exchange revenues or from contracts with the Independent System Operator...." (Emphasis added).

Fuel costs for Santa Catalina Island which are incurred since the passage of AB 1890 are "going forward" costs and are therefore subject to the provisions of § 367(c). The statute does not make exceptions for the recovery of fuel costs in isolated regions, such as Santa Catalina.[5] Edison's proposal to recover them through the TRA would offset headroom, thereby effectively permitting their recovery in distribution rates. We have already stated that these costs may not be recovered in distribution rates (D.97-11-073).

Whether or not Edison should be able to recover Santa Catalina fuel costs through the TRA as a matter of fairness, the recovery of those costs from a source other than the PX or ISO is precluded by § 367(c). Assembly Bill (AB) 1890 is a complex set of statutes that guides the evolution of electric industry restructuring. Under its provisions, the utilities are presented with certain benefits and advantages as a tradeoff for certain sacrifices. We must presume the loss of Santa Catalina fuel costs is one of those sacrifices. On that basis, we cannot adopt the component of the stipulation that would provide for such recovery.

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[5] Resolution E-3564 authorized the establishment of the SCIDF memorandum account to track fuel costs on Santa Catalina. It did not, however, authorize recovery of the amounts, deferring the matter to later review: "Although the statute suggests that these costs should be recovered through revenue from the ISO or PX, merely tracking them in this account does not guarantee their recovery." The resolution goes on to say "... the establishment of that account does not allow for automatic recovery of the costs booked to it."

We adopt the stipulation between ORA and Edison as it is presented with the exception of the provision permitting Edison to recover Santa Catalina fuel costs in the TRA. We are not concerned that removing one element from the larger package unduly compromises the parties' agreement: each remaining component of the stipulation is reasonable, supported by the record and lawful.

G. Stipulation between PG&E and ORA

PG&E and ORA filed a stipulation resolving several cost allocation and rate design issues as follows:

Distribution Revenue Requirement Allocation. The stipulation establishes a method for calculating the distribution revenue requirement allocation;

CARE Discount and Surcharge. The CARE discount will be expressed as a reduction to distribution charges on customers' bills. The CARE surcharge will be included in the PPP amount shown on customers' bills. The CARE surcharge exemption will be expressed as a lower PPP amount on exempt customers' bills. PG&E will implement the mechanism in utility accounts by setting the authorized level for the distribution revenue requirement in the TRA at the amount for distribution before being reduced for the CARE discount. The authorized level for the PPP revenue requirement in the TRA will be set at the amount for PPP before the CARE surcharge revenue is added.

Allocation of PPP and Nuclear Decommissioning. The portion of PPP which does not include the CARE surcharge and amounts for nuclear decommissioning will be allocated based on the system average percentage method.

Residential Minimum Bill Calculation. No later than September 1999, PG&E will calculate the minimum bill according to the customer's average usage by function and assign the residual amount (the difference between the $5 minimum bill and the rates for functions other than distribution) to distribution.

Elimination of Memorandum and Balancing Accounts. PG&E and ORA agree to eliminate the balancing and memorandum accounts as proposed in ORA's revised Table 2-1. The parties agree to consider generation accounts and the TCBA in the ATCP.

Update to Revenue Requirements. PG&E will change its rates after the Commission has issued a decision in PG&E 1999 general rate case proceeding A.97-12-020 and will update other revenue requirements after December 31, 1998 to reflect the impact of relevant Commission decisions issued after that date.

BART objects to that portion of the stipulation which affects schedule E-20T. As discussed above, BART's argument in this regard is premised on the assumption that we may adopt functional cost allocations, a practice we have found to be unlawful during the transition period for all rates and customer groups. With this clarification, we adopt the settlement between ORA and PG&E.

III. PX Pricing Issues

A. Stipulation Between PG&E, WPTF and Enron

PG&E, Enron and WPTF filed a stipulation with regard to the direct access minimum bill and the public release of all inputs PG&E uses to calculate the PX credit.

With regard to the minimum bill, PG&E explains that all three utilities' tariffs provide that when a direct access customer's PX credit exceeds the amount of the otherwise applicable "bundled" bill (that is, a bill that includes charges for all utility services, such as distribution and transmission), the customer's total utility charges will be equal to zero. Thus, the customer would not receive a negative bill (or credit), even if the PX credit exceeds the total bill.

The Commission approved this provision in Resolution E-3510 finding that the zero minimum bill was essentially approved by D.97-08-056. In this proceeding, WPTF proposed eliminating the zero minimum bill arguing that it is a disincentive to direct access. Direct access customers will receive the benefit of PG&E's agreement to eliminate the direct access zero minimum bill from the effective date of this decision through bill credits. The settlement filed herein eliminates the zero minimum bill. PG&E will implement the change directly in bills as soon as its billing system is able to accommodate the change. PG&E also agrees to refund credits to the direct access customer's bill which would not have been charged in the absence of the zero minimum bill provision. Such refunds would not be necessary after the zero minimum bill is implemented on its billing system.

In this proceeding, Enron and WPTF also proposed that the utilities make public any information used to calculate the PX credit. The stipulation they reached with PG&E essentially withdraws this proposal and requires only that PG&E continue to make public that information which it currently provides to interested parties. That information is (1) load profile data; (2) hourly prices; (3) 30-day average prices for each rate schedule (or multiple week averages as the Commission requires); and (4) distribution loss factors.

No party opposes the stipulation between PG&E, Enron and WPTF. The stipulation reasonably resolves issues relating to PG&E's minimum bill and PG&E's disclosure of information used to calculate the PX credit. We therefore adopt it.

B. Stipulation Between Edison, Enron, and WPTF

The stipulation between Edison, Enron, and WPTF is essentially the same as that presented for PG&E, that is, that Edison will eliminate the minimum

Enron, Commonwealth, and WPTF contend that the PX credit as presently constituted needs to include additional cost items in order to reflect the costs utilities incur in providing bundled energy service. Enron believes omission of these costs from the PX credit places competitors in generation markets at a disadvantage because customers who use competitors' services must pay for costs of the utility's power supply, even though they do not use it. Hence, these direct access customers pay twice for power. DGS makes similar comments, arguing that the PX credit must include all costs that are relevant to power generation, including costs of marketing, customer service, rate design, and Administrative and General (A&G). If these costs are not included in the credit, DGS argues, direct access customers pay for them by way of distribution rates although direct access customers make no use of the utility's (generation) procurement services.

In enumerating the costs which it argues are being improperly omitted from the PX credit calculation, Enron distinguishes "internally managed" and "externally managed" costs. "Internally managed" costs are those incurred within a utility's operation, and "externally managed" costs are those billed to a utility by third parties, such as the PX.

1. Internally Managed Costs

Of the internally managed costs, Enron proposes that a share of the cost of forecasting load, dealing with the PX, A&G expenses, taxes, customer service, rate design, and advertising expenses should be reflected in the PX credit. Enron relies on company data to estimate PG&E's annual revenue requirement for procurement activities at $12 million and procurement-related A&G at $7.5 million. Enron states it is unable to calculate comparable figures for Edison and SDG&E because the data was not available in the course of the proceeding. Commonwealth adds that some portion of customer service costs bill provisions of its tariffs and will not be required to disclose more information about the PX calculation than it already makes public. We adopt the stipulation.

C. Stipulation Between SDG&E, Enron, and WPTF

The stipulation between SDG&E, Enron, and WPTF is essentially the same as that presented for PG&E, that is, that SDG&E will eliminate the minimum bill provisions of its tariffs and will not be required to disclose more information about the PX calculation than it already makes public. We adopt the stipulation.

D. PX Credits

Under the restructured electricity market in California, customers may subscribe to "bundled service" from the utility distribution company 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. Customers who elect direct access service receive a credit on their bills called the PX Credit. The credit offsets the energy costs included in the bundled rate.

Issues relating to the calculation of the PX credit were the source of substantial controversy among several parties. Generally, Enron, Commonwealth, and WPTF advocate substantial changes to the existing PX credit. These parties seek modifications to the cost components of the credit, the methodology employed in its computation, and the handling of input data to the calculation. Other intervenors, including DGS, TURN, and ORA, advocate less extensive changes to the credit. Edison, PG&E, and SDG&E defend the existing structure of the credit, but seek certain changes in computation methodologies, as well as Commission authorization for the inclusion of "ex-post market" costs in the PX credit.

Discussion. As a preliminary matter, we find that the proposals of Enron, Commonwealth and WPTF are appropriately considered in this proceeding. We agreed to consider these matters in the scoping memo of this proceeding. Moreover, contrary to the utilities' assumption, our findings in D.97-08-056 did not suggest the matter was resolved once and for all. D.97-08-056 addressed the components of the PX calculation there in only the most cursory fashion. Were we to limit ourselves to an arithmetic verification of the utilities' calculations, we could not take up even the modest changes the utilities propose.

The question for resolution here is whether certain utility direct and overhead costs should be recognized in the credit for the PX or be assumed solely by utility generation customers. 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.

No party disputes that energy competitors incur the types of costs Enron would have included in the PX credit or that competitors must ultimately recover those costs in order to remain viable. 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. As part of that strategy utility pricing must eliminate any "competitive advantage created by an institutionalized removal of costs otherwise intrinsic to the provision of a should be considered energy-related and therefore allocated to the PX credit. WPTF and DGS join Enron and Commonwealth in advocating that such "procurement costs" be included in the PX credit.

Edison, PG&E and SDG&E oppose the inclusion of any additional categories of ongoing costs in the PX credit. SDG&E argues that D.97-08-056 and Resolution E-3510 specified the costs to be included in the PX credit. Although the Commission did not use the term "avoided costs" in those documents, SDG&E argues, all of the costs the Commission directed the utilities to include in the PX credit are, in fact, avoidable costs. Similarly, PG&E observes that Enron proposes approval of a fully allocated costing methodology for the PX credit, methodology which the Commission rejected for revenue cycle services in D.98-09-070, finding that such pricing methods were not necessary to assure market entry by competitors.

SDG&E observes that if it were to include a share of internally managed costs in the PX credit, it would have to compete for energy customers. SDG&E argues this would represent a marked departure from the Commission's current market framework, which presumes the utilities are default providers without a competitive role in energy markets. PG&E adds that, if the Commission were to find that additional costs should be included in the PX credit calculation, the record in this proceeding is inadequate to adopt any final calculations.

Edison objects to a review of the PX calculation on the basis that the Coordinating Commissioner's Ruling of May 14, 1998 stated an intent to "expand the scope of the RAP to consider issues which address the accuracy of the PX credits." Edison argues that the term "accuracy" in this context precludes the types of modifications proposed by Enron and others.

service," as DGS' comments describe the utilities' proposals. Future rate design should recognize changes which might occur with regard to the utilities' obligation to serve.

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 cost 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.

The record in this proceeding does not permit us to establish rates which recognize long run marginal costs. We adopt the utility proposals with the understanding that they are interim and subject to revision in the next RAP proceeding. There, we will set the PX credit recognizing policy determinations made in other proceedings, such as the post-transition ratemaking applications, the distribution rulemaking, or a rulemaking on market structure should we initiate one in the near future.

2. Externally Managed Costs

Enron proposes that externally managed costs ought to be reflected in the PX credit. Such costs include ongoing expenses such as the ISO Grid Management fee, and a variety of related charges. Other external costs are those related to PX start-up and development expenses, which are not considered ongoing. Enron estimates these costs to be about $45 million for PG&E, a similar amount for Edison, and $10 million for SDG&E through the year 2001.

The utilities do not dispute the appropriateness of including externally managed costs that are ongoing. PG&E claims that all of these costs are either already reflected in the PX credit, or will be if Advice Letter 1781-E-A is approved. Edison and SDG&E also state that their PX crediting procedures recognize these costs. Enron does not contest these claims. The remaining issue is whether the PX startup and development costs should be included in the PX credit.

Enron observes that all energy providers must pay for start-up costs. Under current utility rate design, according to Enron, customers of competitive energy providers pay twice for these costs, once to their energy providers and again to the utilities by way of distribution rates. Commonwealth and WPTF support Enron's proposal. CLECA/CMA argue that including PX startup expenses in the PX credit would be consistent with D.97-08-056 and Resolution E-3510.

Edison, PG&E and SDG&E oppose including PX start-up costs in the PX credit. They assert that the PX is an integral part of the state's restructured electric industry and that, accordingly, all customers should share the expense of creating the PX. The utilities point out that all customers have the option of purchasing power from the PX, and that the PX is the default supplier of energy to all customers. Edison notes that competitors may use the PX as a scheduling coordinator. PG&E observes that, although any scheduling coordinator may purchase power through the PX, only the utilities pay the PX start-up charges.

Edison proposes that, should the Commission find that only bundled customers should bear the PX startup expenses, the Commission also should direct the utilities to recover the costs of Direct Access Service Request (DASR) processing entirely from direct access customers. Presently, all customers share these costs. Enron says there would be no need for such a quid pro quo, because DASR expenses benefit all customers by making it possible for customers to select an energy provider.

TURN, DGS and ORA oppose including PX start-up costs in the PX credit. They argue that all customers should share these costs because the costs were incurred as part of the creation of the restructured, competitive electricity market in California. ORA adds that the position of the PX as the default energy provider in the state distinguishes it from competitive energy providers and from other scheduling coordinators, which are free to enter and leave the market, and which be selective regarding the customers they serve.

Discussion. The implementation of direct access would not have been possible without the implementation of the PX. In D.95-12-063, we found that the PX would "foster and sustain the development of a transparent spot market for the generation of electricity" in order to provide price signals to generators, buyers and consumers. The PX is a source of market price information that may be used in forming direct access contracts. The PX acts as a scheduling coordinator and energy broker. All of these activities benefit direct access customers as well as those purchasing power from the distribution utility. Commission policy provides generally that customers who benefit from a cost should assume liability for the cost. Accordingly, all customers should assume liability for start-up expenses. We will not require the utilities to modify their PX credit calculations to reflect the PX start-up and development costs.

E. Post-Real Time Settlement Costs

On June 29, 1998, PG&E filed Advice Letter 1781-E in which PG&E proposes to include "Post-Real Time Settlement Costs" in the PX credit. On August 27, 1998, PG&E amended Advice Letter 1781-E-A to specify the post-settlement costs that would be included in the PX credit. The advice letter would incorporate into the PX credit amounts billed to PG&E by the PX after the settlements process for a given day is finished (91 days following the trading day), or amounts billed to PG&E as lump-sum dollar amounts (not identified with a particular day's energy costs). The advice letter specifies charges for black start capability, PX administration, and ISO grid management.

The Assigned Commissioner's Ruling Supplementing Scoping Memo, issued September 24, 1998, incorporated this matter into this proceeding. The advice letter was not protested and no party has opposed the proposed changes here. ORA believes PG&E's existing tariff language already encompasses the "ex-post" costs, but supports the proposed new tariff language as a useful clarification.

Edison states that its existing tariff language is broad enough to include all the costs that are the subjects of PG&E's advice letter. Therefore, Edison states that its tariff will not require any modifications. SDG&E makes the same observation, although SDG&E seeks to alter how it computes these elements of the credit, as discussed below.

D.97-08-056 approved Edison's methodology for the recovery of these "ex-post market" costs in the PX credit. While the utilities' computations may differ, the cost components of the PX credit should be the same for the three companies. Accordingly, we adopt the changes proposed by PG&E in

Advice Letter 1781-E-A, except for the inclusion of PX start-up costs in the PX rate, which PG&E is no longer proposing.

F. Audits of PX Credit Calculations

In its testimony, PG&E proposed to sponsor an independent audit of the PX credit calculations to be performed monthly by a neutral auditor chosen by the utilities and approved by the Commission. Enron and WTPF raised concerns that the audits would not go far enough to assure correct calculations. SDG&E and Edison did not object to PG&E's proposal as it would affect their own calculations.

After submission of the record, on March 11, 1999, PG&E, Edison, SDG&E and WPTF filed a stipulation in this proceeding with a request for its approval and motion for waiver of the Commission's procedural rules which guide the review of settlements.

With regard to waiver of our rules, the parties explain that their late filing resulted from ongoing collaboration and compromise. They ask the Commission to permit parties to address the stipulation in their comment on the proposed decision rather than pursuant to the procedures outlined in Rules 51.1, 51.2 and 51.4. We grant this motion for waiver and have permitted the parties to comment on the stipulation in comments to the ALJ's proposed decision.

The substantive elements of the stipulation set forth a procedure for auditing the utilities' calculation of their respective PX credits. Specifically, it provides that the Commission would select an auditor from a list developed by the utilities and three competitors. The auditor, who would be paid by the utilities, would review the PX calculations for consistency with Commission decisions and provide a monthly report to the Commission in this regard. The utilities will modify the PX credits according to the audit report with the understanding that neither the utilities nor other parties waive their right to challenge the calculation in subsequent revenue adjustment proceedings.

The stipulation does not resolve whether the audit procedure would end with the termination of the rate freeze or continue after that time.

We adopt the stipulation. In doing so, we do not delegate our authority or responsibility to a third party to assure the PX credit calculations are consistent with our orders and are otherwise lawful. The audits will provide additional confidence in the utilities calculations but they will not affect the rights of the Commission, its staff or other parties to review the calculations as the stipulation specifies. We find that this procedure should continue until and unless the Commission directs otherwise and with the understanding that the process for calculating the PX credit may change or be eliminated.

G. Estimating Ex-Post Market Costs

SDG&E proposes to modify the mechanism for ex-post market costs[6] by estimating certain inputs. SDG&E says its proposed procedure will improve the accuracy of the PX credit by reducing the effects of the time lag. The time lag occurs because the PX settlements process, which establishes ex-post costs, can take several months. SDG&E provided an example in which ex-post costs incurred in April and based on April demand, are recovered in August when demand is considerably higher. As a result, prices are inaccurate and the utility recovers either too much or too little, depending on the circumstances. SDG&E comments that the problem is worsened by the fact that ex-post costs are much

[6] SDG&E states ex-post market costs include Day-Ahead Ancillary Services, Hour-Ahead Ancillary Services, Replacement Reserve, Real Time Energy, Imbalance Energy, Unaccounted-For Energy, and management charges from both the PX and ISO.

higher than the utilities expected, constituting 10% to 30% of SDG&E's total PX price.

To address the problem, SDG&E proposes to estimate ex-post costs in setting the PX price rather than relying entirely on actual data. The estimates would be calculated using actual unit prices and estimated volumes. The data is available soon after the trading day. SDG&E would incorporate the actual costs into a later month's PX.

No party opposed SDG&E's proposal. Commonwealth, DGS, ORA, and TURN support the SDG&E proposal. Enron and WPTF support the change for SDG&E, and also advocate its use by Edison and PG&E. Edison and PG&E agree in principle with the SDG&E proposal, and are willing to study it. However, PG&E says the PG&E data processing system cannot accommodate such a method. Edison states that the SDG&E proposal would require forecasting certain charges.

Edison's objection to the SDG&E calculation is not compelling. The change would require Edison to estimate only quantities, not prices. Even poor estimates would represent an improvement over existing practice and would be subject to a true up based on actual data, as it becomes available. PG&E's problem is familiar based on its representations in other proceedings with regard to the limitations of its current operations. The SDG&E proposal represents an improvement in the seasonal price signals of the PX rate. We adopt it for SDG&E. We direct Edison to incorporate the change to its PX rate calculations no later than the end of 1999. PG&E already incorporates ex post expenses in its PX credit calculation on a time of use basis.

H. Calculating Ex-Post Expenses Based on Time of Use

The parties addressed whether in calculating the PX credit, the utilities should incorporate ex-post expenses based on time of use. PG&E assigns these costs to specific hours of the day, corresponding to billing by the PX. Edison and SDG&E have spread these costs across all hours of the day. Edison offers to switch to the time-of-use methodology. SDG&E advocates retaining its existing method for incorporating these costs into the PX credit.

Commonwealth and TURN recommend that the Commission adopt a time-of-use method. TURN argues that averaging costs across all hours in the month, "means that high ancillary service and imbalance energy costs incurred during peak summer afternoon demand periods end up spread to consumption that takes place in off-peak night and weekend periods. This creates another pricing distortion..."

SDG&E argues that time-of-use treatment of PX bills also introduces distortions, because the PX bills some costs in ways that do not correspond to the time incurred. SDG&E observes, for example, that some PX charges are billed to the first hour of the last day of the month, even though the corresponding services were provided over periods of a month or more.

The PX credit should reflect corresponding costs so far as is practical. Ideally, the utilities would be able to treat "ex-post" costs in ways that avoid any type of pricing distortions. We will direct PG&E and Edison to incorporate the change to the calculation to correspond to time of use. We will not order SDG&E to do so at this time but recognize that the issue may come up in subsequent proceedings as the utilities refine the methods they use to calculate the PX credit.

IV. Other Ratemaking Issues

A. Devers Palo Verde 2 Costs

Devers Palo Verde 2 (DPV2) is a transmission project Edison abandoned before completing construction. The cost of the abandoned project is $6.704 million. Pursuant to D.97-11-073, Edison entered the amount into its ERAM, now TCBA, for recovery in rates. The $6.704 million was subject to refund pending the FERC's review of the costs. FERC subsequently approved $3.352 million of the costs for recovery in transmission rates and found that the remaining costs of the plant should be assumed by Edison's shareholders. By Advice Letter 1301-E, Edison asked the Commission to include the $3.352 million in transmission rates that FERC approved for the project. Resolution E-3547 approved the amount in the transmission portion of Edison's rates, consistent with D.97-11-073 and the FERC decision.

In this proceeding, Edison seeks recovery of $3.352 million in costs associated with DPV2, which have been disallowed by the FERC. TURN opposes Edison's request here for recovery of the amounts the FERC disallowed and allocated to shareholders. The Commission, TURN argues, should not include in rates costs which a federal agency has disallowed. DGS makes similar comments in its reply brief.[7]

Edison's request to recover funds disallowed by the FERC is effectively a request that we vacate the order of a federal agency. We could only approve Edison 's proposal here by ignoring the FERC's explicit requirement that shareholders assume liability for half of DPV2-related costs. While the Commission did state in D.97-11-073 that "If the FERC does not permit them to be included in transmission rates, we will permit their recovery in Commission jurisdictional rates..." (mimeo, p. 11), in our view, FERC did permit recovery of these costs based on precedent of only allowing 50% recovery for canceled plant costs. We decline to take action in defiance of a federal order for costs that are subject to FERC's exclusive jurisdiction. Moreover, we never intended that

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[7] TURN argues that the TCBA should be adjusted by $6.704 million to avoid double recovery of the amounts associated with the project. Edison would reduce the TCBA $3.352 million so as to allow it to recover the amounts disallowed by FERC.

Edison would recover transmission costs in distribution rates or other CPUC-jurisdictional rates. Edison does not demonstrate or even argue that the subject costs are anything but transmission costs. D.97-08-056 stated our uncontested view that "FERC will have sole responsibility to set transmission revenue requirements" and deference to the provisions of § 368(b) requiring "the identification and separation of individual rate components such as charges for energy, transmission, distribution, public benefit programs, and recovery of uneconomic costs." By including transmission costs in any other rate, Edison would ignore this requirement of AB 1890 and our decision. Edison shall reduce its TCBA $6.704 million and may continue to recover the $3.352 million approved by the FERC and included in its transmission rates.

B. Reliability Must Run (RMR) Costs

All three applicant utilities include in their CTCs those costs relating to "reliability must run" contracts. RMR generation costs arise from contracts entered into by the ISO with all types of generation providers for the purpose of ensuring the reliability of the transmission system.

Enron argues that including RMR costs in the CTC gives customers the false impression that the costs will be eliminated at the end of the transition period, although they are ongoing. Enron proposes that the Commission require the utilities to unbundle these costs and include them on customer bills as a separate rate component.

Edison opposes Enron's recommendation, arguing that the Commission has already resolved the issue in D.97-12-109. Edison believes it cannot readily implement an alternative to the existing convention prior to the end of the transition period. It comments that these costs will be included in transmission rates at a later date. PG&E makes similar comments.

We will not require the development of a separate rate element at this time, as Enron proposes, because it may cause additional customer confusion without creating offsetting benefits. As we stated in D.97-12-109, RMR costs are those associated with either transmission or generation. They are currently recovered through a separate accounting in the TRA. After the transition period ends, however, we will have no jurisdiction to set transmission rates. The utilities will need to take steps to recover the amounts by way of transmission rates. Alternatively, we will consider including the costs in generation rates, depending on whether and how we set those rates, if the utilities are able to demonstrate that the costs are related to generation.

C. SDG&E's Proposal to Cancel Rate Options

SDG&E proposes to eliminate certain residential and small customer rate options, effective at the end of the rate freeze period. Enron supports SDG&E's proposal on the basis that the utilities should not provide optional rates schedules.

ORA objects to SDG&E's proposal, arguing that the Commission has not yet determined the extent to which a utility should be required to offer various rate options to small customers. ORA would defer the matter to SDG&E's post-transition period ratemaking application.

The utilities have filed post-transition period ratemaking applications in which we will consider limited rate design following the transition period. SDG&E has proposed a comprehensive rate design proceeding at a later date. We decline to consider the matter piecemeal here and accordingly deny SDG&E's request to eliminate rate options for small customers effective at the end of the transition period.

D. SDG&E's Balancing Account Overcollections

SDG&E has collected about $8 million more than its costs in various balancing and memorandum accounts and proposes to credit the TRA accordingly. The accounts in question track Demand Side Management (DSM), Research, Development and Demonstration (RD&D) and CARE costs and revenues prior to January 1, 1998. Specifically, SDG&E would offset a $28 million shortfall in the industry restructuring memorandum accounts, the DSM pilot bidding program and a handful of smaller accounts with a $35 million over collection in DSM, CARE, and RD&D accounts. Alternatively, SDG&E proposes to transfer the overcollections to the TCBA to reduce transition costs.

ORA opposes SDG&E's proposal to aggregate balances because doing so would allow SDG&E to recover certain costs for which it has not received approval. ORA prefers that the Commission defer the disposition of overcollections to the Energy Division's pending review of existing account balances.

We agree with ORA that this proceeding is not the appropriate forum to consider the reasonableness of the costs in these accounts. We are also concerned that SDG&E's proposal as it is presented may overlook the requirements of Section 367 which, as we have found previously in this decision, limits the Commission's discretion with regard to changes in cost allocation between customer groups. Specifically, SDG&E recovered the CARE, DSM and RD&D costs on an equal cents per kilowatt hour basis, consistent with the cost allocation method in effect on June 10, 1996. To refund the amounts according to the cost allocation method used for the TCBA would constitute a change in cost allocation method. The cost allocation method applied to the TCBA is EPMC. In our discussion regarding restructuring implementation costs, we found that Section 367 does not permit a change in cost allocation from past practice even for those costs which are not specifically identified as transition costs. This interpretation is consistent with SDG&E's view on the matter. SDG&E's proposal as presented may also violate Section 381, which requires that public purpose funds are not "commingled with other revenues."

In order to comply with the Section 367 and Section 381, we will permit SDG&E to transfer the balances to the TCBA but require SDG&E to refund the amounts in proportion to how they were collected from each customer group. Therefore, SDG&E would credit its RGTCOMA subaccounts using the equal cents per kilowatt hour method of cost allocation.

In addition, the reasonableness of the costs remain subject to review, audit, and potential disallowance even though we authorize this transfer. We are comfortable with this approach because, if disallowances were identified, such disallowances would only serve to increase the amount of overcollection, thus increasing the amount transferred to the TCBA. With these conditions, we see little risk to ratepayers of authorizing transfer of existing overcollections at this time.

E. PG&E's Incremental Tax Memorandum Account

PG&E proposes the creation of a new memorandum account for tax liabilities. TURN opposes it on the basis that it is "a remnant of the era of balancing account ratemaking" and therefore contrary to the Commission's current ratemaking policy.

As TURN observes, PG&E may gain or lose in any given category of costs. We decline to create new balancing accounts to shield the utilities from the risks that all businesses must assume, such as those relating to changes in tax law. We reject PG&E's proposal to create an Incremental Tax Memorandum Account.

F. Edison's Wholesale Contract Costs

Enron recommends that Edison be required to remove from the TRA costs associated with inter-utility contracts and resale city wholesale contracts. Edison agrees that it inappropriately included those costs in the TRA and will adjust the TRA accounts accordingly.

G. Calculating Residual Revenues Transferred to the TCBA

Enron recommends that each utility use the same methodology for calculating residual revenues transferred to the TCBA. Edison and PG&E reply that each utility is performing the calculation in compliance with Commission-approved tariffs. We agree that the Commission may have adopted slightly different methods for calculating the TCBA revenues. We find no compelling reason to change them here in order to make them consistent across the utilities.

V. Uncontested Matters Raised by the Applications

A. PG&E

PG&E asks the Commission to approve the following uncontested proposals which would permit PG&E to:

1. Consolidate and unbundle the 1999 revenue requirement;
2. Include shareholder incentives in the 1999 revenue requirement if a decision is rendered on A.98-05-001 before a decision in the current RAP proceeding or, alternatively, recovery through the 1999 RAP;
3. Transfer balances in the Streamlining Residual Account, Hazardous Substance Mechanism and Electric Vehicle Balancing Account to the distribution revenue requirement;
4. Finalize entries to the TRA for the record period, January 1 through May 31, 1998, subject to any adjustment required by the Commission's December 31, 1998 headroom audit;
5. Transfer funds for the CARE discount from the PPP to the distribution function;

6. Include shareholder participation credit amounts recorded to the TRA for the record period, January 1, 1998, through Mary 31, 1998, subject to future adjustment as a result of the review that will occur in the 1999 RAP; and

7. Implement proposals for interim rates and functional rate design.

We find PG&E's uncontested proposals reasonable at this time and adopt them herein with the condition that all changes to revenue requirements which have not been the subject of a reasonableness review will be authorized on an interim basis pending the Commission's findings with regard to the audit conducted by the Energy Division or pursuant to decisions issued in future proceedings.

B. Edison

Edison asks the Commission to adopt the following uncontested proposals with regard to revenue requirements:

1. Update its forecast revenue requirement provided in Table II-1 of its report to reflect December 31, 1998 recorded balances in all accounts and Commission decisions issued through the effective date of this order;

2. Update 1999 PBR exclusions, nuclear decommissioning, and public purpose programs revenue requirement to reflect use of a 100% retail allocation factor;

3. Include in the 1999 distribution revenue requirement the PBR exclusions adopted in D.96-09-092 and D.97-08-056 for balances related to the Reduced Capital Recovery Amount and Incremental Return, the Base Rate Performance Memorandum Account, the Electric and Magnetic Fields, the Affiliate Transfer Fee Memorandum Account, Non-Utility Affiliate Credits, the Hazardous Waste Balancing Account and the Catastrophic Event Memorandum Account (CEMA);

4. Include in the Nuclear Decommissioning revenue requirement the updated balance, the annual revenue requirement of $104.426 million, the San Onofre Nuclear Generating Station Unit No. 1 Shutdown O&M revenue requirement of $11.522 million, the Department of Energy Decontamination and Decommissioning Fee revenue requirement amount of $4.642 million, the balance in the SRA, the Spent Nuclear Fuel Storage fee revenue requirement amount of $3.27 million and the balance in the SRA associated with Spent Nuclear Storage Fees; and

5. Include in the PPP revenue requirement costs associated with RD&D royalties, low emission vehicles, $7.36 million in Low Income Program Plans, the $0.958 million cost of administering the CARE, the balance of the costs and revenues in the CARE Adjustment Account, and the balance in the SRA associated with intervenor compensation costs.

Edison asks for approval of several proposals concerning revenue allocation, rate design, balancing accounts, and sales forecasts:

1. Update the nongeneration EPMC percentages used to allocate the PBR exclusions with Edison's 1999 sales forecast and convert those allocated revenues to a cents-per-kilowatt hour rate;

2. Change the distribution revenue requirement to reflect the cost of capital trigger mechanism and allocate the change using EPMC;

3. Include in the PPP charge the CARE surcharge amount of $.00079 per kilowatt hour;

4. Use Edison's 1999 retail sales forecast of 77,300 gigawatthours to calculate the PBR Exclusions, Nuclear Decommissioning, and PPP rates;

5. Transfer the Optional Pricing Adjustment Clause Balancing Account balance to the TRRA following review of the 1997 Flexible Pricing Options Annual Report and a

determination that the shareholders contributions have been correctly calculated;

6. Approve the recorded entries to the TRA and the RGTMA for the period January 1998 to May 1998 subject to the Energy Division's audit; and

7. Include the balancing and memorandum account balances in the TCBA subject to the Commission's further review of the Energy Division's audit.

We adopt the uncontested proposals of Edison with the following conditions. Those increases in distribution rates which are attributable to CEMA costs shall be limited to those for which the Commission has issued a decision finding the costs to be reasonable and associated with distribution facilities, consistent with D.97-08-056 and D.97-12-109. Similarly, changes in rate components associated with balancing accounts for which the Commission has not issued a finding of reasonableness are authorized on an interim basis pending the Commission's findings with regard to the audit conducted by the Energy Division or pursuant to decisions issued in other proceedings.

C. SDG&E

SDG&E asks the Commission to approve the following uncontested proposals:

1. Adoption of SDG&E's proposed revenue requirement which is derived from D.97-08-056, updated to account for Commission orders in various subsequent and pending proceedings;

2. Adoption of SDG&E's proposed revenue allocation as set forth in rebuttal testimony for the distribution revenue requirement and in its stipulation with ORA for various other functions;

3. Termination of certain generation related rate schedules which SDG&E states are currently unused, including A-

V6,AL-TOU-C,RTP-1,1-2, and the "signaled period " rate option with AL-TOU;

4. Inclusion of a new option for metal halide lamps in Schedule LS-1 and LS-2, with rates equal to those used for unit charges for existing metal halide rate options;

5. Adoption of the calculation of "headroom," which is based on a methodology already approved by the Commission; and

6. Adoption of SDG&E's entries into its RGTCOMA, which tracks transition cost obligations by rate group pursuant to D.97-06-060.

We find these proposals for SDG&E to be reasonable, and we adopt them with the conditions described for Edison and PG&E.

VI. SDG&E's Post-Rate Freeze Rate Design and Cost Allocation

Since the submittal of this proceeding, the Commission issued an order in A.99-02-029 approving a settlement that would guide accounting and ratemaking after SDG&E's rate freeze period ends, on or about July 1, 1999. In the process of reviewing the settlement, SDG&E informed the Commission and active parties of rate changes forecasted to occur with the end of the rate freeze period. SDG&E estimated that rates for industrial customers and large commercial customers are likely to decrease substantially but does not expect residential rates to fall. The circumstance concerns us and we wonder what underlying facts cause it. We add to this concern our view that SDG&E's rates and costs should be reviewed for the post-rate freeze period. This decision declines to modify cost allocations on the basis that AB 1890 precludes any modifications at this time. The law does not circumscribe our actions in this regard following the rate freeze, however. Accordingly, we direct SDG&E to file an application to revise its rates and cost allocations. This rate design application will include review of SDG&E's

marginal costs and the allocation of various costs between customer classes, including costs associated with implementing direct access and the liabilities which will remain recoverable by way of the CTC.

Comments on Proposed Decision

The Assigned ALJ issued a proposed decision for comment pursuant to Section 311. Several parties filed comments on the proposed decision, including all three applicants, ORA, TURN, Enron, CMA/CLECA, DGS, and BART. This decision includes a number of minor changes and corrections to the proposed decision on the basis of the parties' comments. The decision also adopts a long run marginal cost method for calculations of the PX credit in future RAP applications.

Findings of Fact

1. Changing the allocation of one type of cost affects the relative burden of the CTC among customer groups, indirectly changing the cost allocation in effect June 10, 1996, which would be in contravention of § 367(e)(1) during the transition period.

2. The rates in effect on June 10, 1996 were allocated between customer groups using a total EPMC methodology, also known as system average percent methodology.

3. The utilities' proposed allocation of transmission and distribution costs is reasonable and consistent with § 367.

4. BART's proposal to exempt customers on schedule E-20T from assuming some distribution costs would require a functional allocation in contravention of § 367's requirement that the Commission retain allocation in effect June 10, 1996.

5. ORA and SDG&E filed a stipulation that resolves certain disputes regarding cost allocation and rate design matters. The components of the stipulation are reasonable and uncontested.

6. ORA and Edison filed a stipulation that resolves certain disputes regarding cost allocation and rate design matters. With the exception of the stipulation's treatment of Santa Catalina Island fuel cost recovery, the components of the stipulation are uncontested and reasonable.

7. Santa Catalina Island fuel costs are "going forward" costs of operating and maintaining fossil plants and therefore may not be recovered through the TRA mechanism pursuant to § 367(c).

8. ORA and PG&E filed a stipulation that resolves certain disputes regarding cost allocation and rate design. The stipulation's components are reasonable.

9. Enron and WPTF filed stipulations jointly with each of the applicants that resolve certain issues regarding the direct access zero minimum bill and the confidentiality of data used to calculate the PX credit. The stipulations are uncontested and reasonable.

10. Applicants do not include all costs in their PX credit calculations that may be avoidable when customers choose alternative energy providers or those marginal costs which they must incur in the long run. DGS, Enron, and ORA make reasonable arguments that the costs of customer account managers, customer service representatives, self-provision of ancillary services, and financing costs for purchasing power from the PX are avoidable and should therefore be included in the PX credit calculation. An accurate estimate of long run marginal costs would also include certain overhead costs.

11. Direct access would not have been possible without the creation of the PX, which facilitates the formation of direct access contracts, creates a transparent spot market for electric generation, and provides scheduling coordination and energy brokerage.

12. The PX initial charge represents costs that benefit all electric consumers.

13. PG&E's Advice Letter 1781-E-A proposes to modify tariff language to clarify treatment of post-real time or "ex-post" settlement costs billed by the PX. The tariffs of SDG&E and Edison already provide for treatment of such costs.

14. The stipulation of applicants and WPTF, filed March 11, 1999, to conduct an audit of its PX credit calculations is reasonable to the extent it does not delegate Commission regulatory authority to third-party auditors or abridge the rights of Commission staff or parties to review the calculations.

15. SDG&E's proposal to estimate ex-post market costs to avoid the effects of a time lag would improve the accuracy of the PX credit.

16. Applicants' respective proposals for calculating ex-post expenses based on time of use are reasonable at this time.

17. Edison requests to recover from distribution customers' costs associated with DPV2 and which have been disallowed by the FERC. Granting Edison's request would effectively defy a federal order with regard to costs that are within the FERC's exclusive jurisdiction.

18. Enron's proposal to create a new rate element for RMR costs may create customer confusion without providing offsetting benefits to customers.

19. SDG&E requests the elimination of rate schedules after the transition period, a matter which is more appropriately considered in A.99-01-019, SDG&E's application for post-transition period ratemaking mechanisms.

20. SDG&E implicitly requests that the Commission find reasonable certain costs in DSM, RD&D and CARE accounts. This application is not the appropriate forum for determining the reasonableness of such account balances.

21. Transferring overcollections from the DSM, RD&D and CARE accounts to the TCBA results in limited risk to ratepayers.

22. PG&E's proposal to create an incremental tax memorandum account is contrary to Commission policy and otherwise unsupported.

23. The applicants' methods for calculating residual revenues to be transferred to the TCBA have been reviewed and found reasonable as a result of advice letter filings.

24. The utilities make various proposals which are within the scope of the proceeding and uncontested. This proceeding is not the forum in which the Commission has reviewed or will find reasonable amounts entered into balancing accounts for such items as nuclear decommissioning costs, CEMA costs or CARE costs.

Conclusions of Law

1. During the transition period, § 367(e)(1) bars changes to the allocation of transition costs and restructuring implementation costs between customer groups from the allocation in effect June 10, 1996.

2. Section 367(c) provides that all "going forward" costs associated with fossil plant operation and maintenance be recovered solely from the ISO or PX. The statute does not make exceptions for geographic areas in which competition is not expected to develop or for any other circumstances. The recovery of Santa Catalina Island fuel costs through the TRA mechanism is contrary to § 367(c) and therefore unlawful.

3. Applicants should be required to identify in their 1999 RAP Proceedings the long run marginal costs of customer account managers, customer service representatives that result from customers choosing direct access, the costs of self-provision of ancillary services, the financing costs for purchasing power from the PX, and a methodology for the inclusion of these costs into their respective Schedule PX. The PX credit calculation should also include an estimate of other expected long run marginal costs.

4. All customers should bear the costs of creating the PX. Those costs should therefore not be reflected in the PX credit.

5. The Commission should adopt the proposals outlined by PG&E in Advice Letter 1781-E-A and included in the record of this proceeding.

6. The Commission should adopt the stipulation of PG&E and ORA regarding rate design and revenue allocation.

7. The Commission should adopt the stipulation among PG&E, Enron, and WPTF regarding the direct access zero minimum bill and the confidentiality of data used to calculate the PX credit.

8. The Commission should adopt the stipulation of applicants and WPTF to conduct independent audits of PX credit calculations.

9. In determining the PX credit, applicants should be required to calculate ex-post market costs using estimated volumes and actual unit prices.

10. The Commission should deny Edison's request for recovery of DPV2 costs which the FERC has disallowed and should require Edison to credit the TCBA $6.604 million to reflect that denial and the fact that the FERC has included $3.352 million of the total cost in transmission rates.

11. SDG&E's request for the elimination of certain rate schedules following the transition period should be denied and SDG&E should be permitted to revisit the request in A.99-01-019.

12. SDG&E's request to transfer various balancing account overcollections to the TCBA should be granted. SDG&E should not be permitted to close the DSM, RD&D, and CARE accounts until the balances have been determined to be reasonable.

13. The Commission should deny PG&E's request to create an incremental tax memorandum account.

14. The Commission should approve the uncontested proposals of the applicants as set forth herein with the exception that such approval does not imply a finding of reasonableness of any costs which are or should be the subject

of other proceedings and all entries to balancing accounts recognized in rates herein are subject to the Commission's findings with regard to audits conducted by the Commission staff or decisions issued in other proceedings.

ORDER

IT IS ORDERED that:

1. The application of Pacific Gas and Electric Company (PG&E) is granted to the extent set forth herein and with the following exceptions and conditions: (a) PG&E shall conduct an independent audit of Power Exchange (PX) credit calculations as set forth herein; (b) PG&E shall continue to calculate the PX credit by incorporating ex-post expenses based on time of use; (c) PG&E's request to create an incremental tax memorandum account is denied; (d) approval of PG&E's uncontested proposals does not imply a finding of reasonableness of any costs which are or should be the subject of other proceedings, and all entries to balancing accounts recognized in rates herein are subject to the Commission's findings with regard to audits conducted by the Commission staff or decisions issued in other proceedings. PG&E shall file tariffs to carry out this order within 15 days of the effective date of the Commission's order in PG&E's pending 1999 test year general rate case. The tariffs shall implement the provisions of this order and shall not include any proposals that are not authorized by this order. The tariffs shall become effective after Energy Division determines that they are in compliance with this decision.

2. The application of Southern California Edison Company (Edison) is granted to the extent set forth herein and with the following exceptions and conditions: (a) Edison shall not recover Santa Catalina Island fuel costs through the transmission revenue account mechanism; (b) Edison shall credit the Transition Cost on Balancing Account $6.704 million to reflect a denial of

Edison's request to recover costs associated with Devers Palo Verde 2 costs disallowed by the Federal Energy Regulatory (FERC) and to recognize that the FERC has included $3.352 million of the total cost in transmission rates; (c) Edison shall conduct an independent audit of PX credit calculations; (d) approval of Edison's uncontested proposals does not imply a finding of reasonableness of any costs which are or should be the subject of other proceedings, and all entries to balancing accounts recognized in rates herein are subject to the Commission's findings with regard to audits conducted by the Commission staff or decisions issued in other proceedings. Edison shall file tariffs to carry out this order within 15 days of the effective date of this order. The tariffs shall implement the provisions of this order and shall not include any proposals that are not authorized by this order. The tariffs shall become effective after August 2, 1999 or after Energy Division determines that they are in compliance with this decision, whichever is later.

3. The application of San Diego Gas and Electric Company (SDG&E) is granted to the extent set forth herein and with the following exceptions and conditions: (a) SDG&E's request for the elimination of certain rate schedules following the transition period is denied; (b) SDG&E's proposal to aggregate various balancing accounts for purposes of ratemaking is denied but SDG&E's alternative proposal to transfer overcollections to the Transition Cost Balancing Account (TCBA) is granted with the conditions that (1) the balancing accounts not be closed and remain subject to review, audit, and potential disallowance and, (2) SDG&E shall credit each customer group a share of overcollections using the same cost allocation method used to collect the revenues in rates; (c) SDG&E shall conduct an independent audit of PX credit calculations; (d) approval of SDG&E's uncontested proposals does not imply a finding of reasonableness of any costs which are or should be the subject of other proceedings and all entries

to balancing accounts recognized in rates herein are subject to the Commission's findings with regard to audits conducted by the Commission staff or decisions issued in other proceedings. SDG&E shall file tariffs to carry out this order within 15 days of the effective date of this order. If SDG&E's rate freeze ends on or before July 1, 1999, the rate impacts of this order shall be consolidated with the rate changes resulting from Application (A.) 99-02-029. SDG&E shall file an advice letter consistent with the provisions of the decision in A.99-02-029 to reflect the rate changes resulting from this order. If SDG&E expects that the rate freeze will end after July 1, 1999, within 5 days of that determination but not later than June 30, 1999, SDG&E shall file an advice letter consolidating the rate impacts of this order with the rate changes resulting from the decision in A.98-05-019. These tariffs will be effective 30 days after filing subject to Energy Division determining that they are in compliance with this decision. SDG&E shall include in this advice letter filing workpapers clearly delineating rate changes due to this order and the decision in A.98-05-019.

4. PG&E, SDG&E, and Edison 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.

5. On or before December 31, 1999, PG&E, Edison, and SDG&E shall file tariffs applicable to the PX credit calculation which calculate ex-post market costs using estimated volumes and actual unit prices and which incorporate ex-post expenses based on time of use. The tariffs shall become effective after Energy Division determines that they are in compliance with this decision.

6. The stipulation filed March 11, 1999, by PG&E, Edison, SDG&E and Western Power Trading Forum regarding audits of utility PX calculations is adopted.

7. Consistent with the stipulation between Edison, SDG&E, Western Power Trading Forum and PG&E, the Commission's Energy Division staff shall, within 30 days of the effective date of this order, select three energy service providers to coordinate with the utilities to provide to the Commission a list of auditors from which to choose the auditor that will perform the PX Credit Auditing Procedure.

8. The stipulation filed December 18, 1998 by PGE& and ORA regarding cost allocation and rate design is adopted.

9. Each Applicant shall file its 1999 revenue adjustment proceeding application no later than 60 days from the effective date of this order.

10. SDG&E shall file, no later than 45 days from the effective date of this order, an application proposing changes to rate design and cost allocation, as set forth herein.

11. Application (A.) 98-07-003, A.98-07-006, and A.98-07-026 are closed.

This order is effective today.

Dated June 10, 1999, at San Francisco, California.

RICHARD A. BILAS
President
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

I abstain.

/s/ LORETTA M. LYNCH
Commissioner

I abstain.

/s/ JOEL Z. HYATT
Commissioner

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