Decision **PROPOSED DECISION OF ALJ MINKIN** (Mailed 3/11/99)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Pacific Gas and Electric Company, to establish the eligibility and seek recovery of certain electric industry restructuring implementation costs as provided for in Public Utilities Code Section 376.	Application 98-05-004 (Filed May 1, 1998)
San Diego Gas & Electric Company, for (1) a determination of eligibility for recovery under Public Utilities Code Section 376 of certain cost categories and activities, (2) a finding of reasonableness of the costs incurred through 12/31/97, (3) approval of an audit methodology for verifying the eligibility of Section 376 costs for recovery from 1998 through 2001, and (4) approval of a section 376 balancing account mechanism to recover eligible costs.	Application 98-05-006 (Filed May 1, 1998)
Southern California Edison Company, to address restructuring implementation costs pursuant to Public Utilities Code Section 376, in compliance with Ordering Paragraph 18 of D97-11-074.	Application 98-05-015 (Filed May 1, 1998)

(See Appendix A for list of appearances.)

INTERIM OPINION REGARDING PUBLIC UTILITIES CODE SECTION 376 AS APPLIED TO PACIFIC GAS AND ELECTRIC COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY

Summary

In this decision, we consider the settlement proposals presented to us by Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) regarding issues related to restructuring implementation costs to which Pub. Util. Code § 376[1] treatment applies. In an accompanying decision in this docket, we have adopted a set of principles or guidelines for considering program eligibility for the implementation costs of Southern California Edison Company (Edison). The goal of these guidelines is to distinguish between those costs that can be properly classified as eligible for § 376 treatment and costs that are not so eligible. In that decision, we also set forth cost recovery principles for eligible costs.

We find that the same principles that we have adopted for Edison should apply to PG&E and SDG&E. Because these guidelines have implications for approving the proposed settlement agreements of PG&E and SDG&E, we address the proposed settlements in this decision. We reject the proposed settlements, without prejudice, and order PG&E and SDG&E to either renegotiate the settlements based on the principles outlined herein or to request alternative relief, consistent with Rule 51.7.

Procedural History

In Decision (D.) 97-11-074, we ordered Edison, PG&E, and SDG&E to file applications to identify restructuring implementation costs incurred under § 376.

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

On May 1, 1998, PG&E, SDG&E, and Edison filed Application (A.) 98-05-004, A.98-05-006, and A.98-05-015, respectively, to identify such costs.[2] Protests were filed by the Office of Ratepayer Advocates (ORA); Enron; jointly by the California Association of Cogenerators (CAC) and the Energy Producers and Users Coalition (EPUC); jointly by the California Manufacturers Association (CMA), the California Large Energy Consumers Association (CLECA), and the California Industrial Users (CIU). PG&E, Edison, and SDG&E replied to these protests. PG&E, Edison, ORA, Enron, and The Utility Reform Network (TURN) filed prehearing conference statements.

On January 1, 1998, Senate Bill (SB) 960 became effective. SB 960 established various procedures for our proceedings. These rules are set forth in §§ 1701, *et seq.* and Article 2.5 of our Rules of Practice and Procedure. In accordance with the SB 960 rules, this proceeding has been categorized as ratesetting (Resolution ALJ 176-2993, as noticed in the Daily Calendar of May 26, 1998).

The first prehearing conference in this proceeding was held on June 25, 1998. On July 10, Commissioner Bilas issued a scoping memo that designated Administrative Law Judge (ALJ) Minkin as the principal hearing officer and set forth the issues to be included in this proceeding. The scoping memo established a procedural schedule under which the Commission would resolve Phase 1 issues by April 30, 1999, and would conclude these proceedings no later than 18 months from the date of filing of the application, pursuant to SB 960, Section 13.

[2] D.97-11-074 ordered the utilities to file these applications by March 31, 1998. This date was extended to May 1, 1998 by authorization of the Executive Director on March 25, 1998.

The Assigned Commissioner's Ruling (ACR) established the scope of this proceeding:

> "In Phase 1, the Commission must determine which programs are necessary to accommodate implementation of direct access, the Independent System Operator (ISO), and the Power Exchange (PX) and thus which costs are potentially eligible for § 376 treatment. Phase 1 will look closely at defining implementation and will focus particularly on cost categorization, i.e., whether the costs claimed should be categorized as costs of implementing electric restructuring and should receive § 376 treatment or whether these expenditures should be categorized as distribution costs, the costs of competing in the new market, or some other cost category, and how cost recovery should occur. In defining implementation, it will be helpful to consider the range of estimates the utilities have provided for 1998 through 2001. While Phase 1 will not review these estimates or adopt any particular dollar figure associated with these forecasts, such estimates will be helpful in understanding the programs the utilities believe are necessary to implement direct access, the ISO, and the PX."

As directed by the ACR, several parties to this proceeding attended a meet and confer session on August 11 and filed a joint case management statement on August 24. At the request of parties, the scoping memo was amended to revise the procedural schedule to allow more time to prepare testimony and rebuttal and to delay the beginning of evidentiary hearings. A second prehearing conference was held on October 8, 1998. ORA submitted testimony on August 31. TURN, Enron, CLECA and CMA (jointly), and CAC and EPUC (jointly) submitted testimony on September 14. Edison, PG&E, SDG&E, ORA and TURN submitted rebuttal testimony on October 5.

Informal discussions among the parties led to two settlement conferences, in conformance with Rule 51, held in San Francisco on October 23 for PG&E and October 20 for SDG&E. PG&E, ORA, CLECA, CMA, EPUC, and CAC filed a motion for adoption of settlement agreement on November 13. On December 3, PG&E filed a supplement that added CIU and University of California/State University of California (UC/CSU) as signatories to the proposed settlement. On November 12, SDG&E, ORA, Federal Executive Agencies (FEA), CMA, CLECA, CAC, EPUC, and UC/CSU filed a motion for adoption of settlement agreement. Enron and TURN filed comments contesting PG&E's proposed settlement. Enron also contested SDG&E's settlement. Evidentiary hearings on the contested issues in the settlements were held on January 4 and 6, 1999. Commissioner Bilas attended the closing arguments on January 13. PG&E's and SDG&E's applications were submitted upon reply briefs filed on February 18, 1999, respectively. PG&E, ORA, CLECA, CMA, and CIU filed joint opening and reply briefs, as did SDG&E, ORA, CMA, CLECA, and FEA. Edison, TURN, and Enron also filed opening and reply briefs. ORA also filed a separate reply brief. The principal hearing officer completed and issued the proposed decision on a timely basis, 21 days after submission.

Framework for Considering § 376 Treatment

Section 376 provides, as follows:

> "To the extent that the costs of programs to accommodate implementation of direct access, the Power Exchange, and the Independent System Operator, that have been funded by an electrical corporation, and have been found by the commission or the Federal Energy Regulatory Commission to be recoverable from the utility's customers, reduce an electrical corporation's opportunity to recover its utility generation-related plant and regulatory assets by the end of the year 2001, the electrical corporation may recover unrecovered utility generation-related plant and regulatory assets after December 31, 2001, in an amount equal to the utility's cost of commission-approved or Federal Energy Regulatory Commission approved restructuring-related implementation programs. An electrical corporation's ability to collect the amounts from retail customers after the year 2001 shall be reduced to the extent the Independent System

> Operator or the Power Exchange reimburses the electrical corporation for the costs of these programs."

Because the costs of establishing the infrastructure underlying the new market structure were not included in rates as of June 10, 1996, the Legislature provided an opportunity for the utilities to be made whole in terms of transition cost recovery. This important concept was discussed in D 97-12-042, in which we articulated the extended nature of transition cost recovery, to the extent such costs are displaced because of recovery of approved restructuring implementation costs.

> "As an initial matter, it is important to understand that § 376 does not directly authorize recovery of [Power Exchange] PX and [Independent System Operator] ISO implementation costs. [footnote omitted.] Rather, it extends the period for recovery of "generation-related plant and regulatory assets" [footnote omitted] to the extent that the opportunity to recover them has been reduced by the collection of specified implementation costs. Thus, § 376 by itself does not authorize recovery of any costs; rather, it permits utilities to recover uneconomic generation-related costs (*see* § 367) beyond the December 31, 2001 deadline set in § 367(a), 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." (D 97-12-042, mimeo. at p. 4.)

PG&E's Proposed Settlement

PG&E and the settling parties ask that we approve a proposed settlement that resolves the issues in both Phase 1 and Phase 2 of this proceeding. The proposed settlement addresses recovery of 1997 and 1998 restructuring implementation costs as well as the maximum amount that PG&E can claim for § 376 treatment, i.e., amounts that might lead to an extension of transition cost recovery after the rate freeze ends.

Under the proposed settlement, costs would be separated into two categories. Externally managed restructuring costs consist of FERC-approved ISO and PX start-up and development costs and Commission-approved consumer education program costs. Internally managed restructuring costs consist primarily of the costs of direct access implementation and demand PX bidding and settlement systems. The settlement proposes that 1) only externally managed costs be eligible for § 376 treatment, 2) these costs are fully recoverable, and 3) PG&E agrees to cap this treatment at $95 million, i.e., to the extent that recovery of externally managed costs displace generation-related transition cost recovery by December 31, 2001, only $95 million will be recovered in the post-transition period.

The settling parties agree that PG&E will waive § 376 treatment of all internally managed implementation costs, including all such costs included in its 1999 General Rate Case (GRC) application (A.) 97-12-020. These costs consist primarily of the costs of direct access implementation and demand PX bidding and settlement systems. For 1997 and 1998, the settling parties agree that 1997 and 1998 internally managed costs are recoverable, but that PG&E will forgo $10 million or approximately 20% of the internally managed costs for 1997 and 1998.

The proposed settlement recommends that generation-related restructuring expense will be eligible for recovery through the Transition Cost Balancing Account (TCBA) mechanism, specifically through the non-must-run and must-run memorandum accounts as going forward costs. Therefore, these costs are not treated as transition costs, but as costs of operating in the market. Generation-related capital costs would either be recoverable in this fashion or as capital revenue requirements based on the results of PG&E's capital additions proceeding, A.98-07-058.

The settling parties propose that the externally managed costs and the internally managed costs be recovered through the Transition Revenue Account (TRA), with cost allocation and verification of entries considered in the Revenue Allocation Proceeding (RAP), A.98-07-006, et al.

The settlement recommends that a new account be established. The Electric Restructuring Costs Account (ERCA) would have two purposes: 1) to allow for the recording and recovery of unanticipated restructuring costs not forecast in PG&E's 1999 GRC and 2) to require the Commission to consider the costs of new restructuring programs before it requires the utilities to incur the costs. Finally, the settling parties propose that PG&E can track in ERCA any costs incurred in its role of scheduling coordinator for municipal utilities and governmental agencies under pre-existing wholesale transmission service contracts which FERC does not allow PG&E to pass on to the contract holders. In effect, this issue is deferred to some future proceeding. Parties take no position on the reasonableness of these costs and reserve the right to oppose any future PG&E request for recovery of these costs.

The parties contend that the settlement is in the public interest and reaches a fair compromise of the disputed issues in this proceeding. The settling parties believe that the public interest is served by establishing three simple eligibility principles and by resolving the reasonableness and recovery issues. For 1997 and 1998, PG&E expects to incur $114.3 million in restructuring implementation expensed costs and $11.6 million in capital costs, for a total of $125.9 million. Out of this total, PG&E has subtracted $13.6 million for which it expects to seek recovery in other forums, externally managed costs of $62.2 million for 1997 and 1998, and a settlement reduction of $10 million. This results in a total of $40.065 million, to which is added $1.2 million in interest and franchise fees and uncollectible expenses (FF&U), for a revenue requirement of $41.279 million in internally managed costs to be recovered through the TRA for 1997 and 1998. PG&E states that it expects to overspend its 1998 estimates by several million dollars. Parties agreed to settle based on the forecast amount, because these forecasts were based on several months of recorded data and the forecast amount would discipline PG&E's expenditures for the remainder of the year. Externally managed costs would continue to be recovered through the TRA on a recorded basis throughout the transition period.

Parties also contend that the settlement is in the public interest because it identifies and addresses the overlap issues with other proceedings and provides a clear roadmap for their resolution. Parties believe that close coordination is required between this proceeding and the GRC. The settlement does not resolve the issue of whether, starting in 1999, PG&E should be authorized to include restructuring implementation costs in base rates or whether such implementation costs should be removed from base rates in the GRC and recovered as incurred, subject to an after-the-fact reasonableness review. If the Commission determines in the GRC that such implementation costs should be removed from base rates in the GRC, then these costs would be eligible for recording in the ERCA. Cost allocation and recovery of implementation costs found reasonable in this proceeding will be addressed in the RAP. The settling parties also propose that recovery of the generation capital additions costs for 1997 and 1998 will be addressed in A 98-07-058, PG&E's capital additions proceeding. Recovery of the costs of Western Power Exchange (WEPEX)-related projects for 1998 will be addressed at FERC and recovered in the transmission revenue requirement. Finally, the settling parties recommend that recovery of expenses related to the generation settlement, billing, and bidding systems for 1997 and 1998 would be recovered as generation going forward costs in 1998 through the TCBA's memorandum accounts. Review of these costs will be addressed in the 1999 Annual Transition Cost Proceeding (ATCP).

SDG&E's Settlement

SDG&E's proposed settlement defines externally managed costs (EMCs) as the actual amounts expended for the PX initial charge, the start-up and development portion of the ISO grid management charge, and the Consumer Education Program and Electric Education Trust costs. Upon approval of the proposed settlement, these EMCs would be deemed to be funded by SDG&E and recoverable from customers pursuant to § 376.

SDG&E defines internally managed costs (IMCs) as direct access implementation costs, PX load bidding and demand settlement costs, ISO/PX interfaces, hourly interval meter installation and reading costs, utility distribution company (UDC) billing systems modification costs, customer information release system costs, and environmental impact report costs. The settlement proposes to fix the revenue requirement for these costs at $35.7 million. The settlement proposes that § 376 IMCs are the portion of IMCs which is eligible to displace generation-related transition cost recovery during the transition period and is fixed at $16.8 million (41.7% of total IMCs). The total amount of transition costs that could be displaced by § 376 recovery is defined as the EMC amount plus the fixed § 376 IMC amount. The settling parties agree that SDG&E should be authorized to recover the full, actual amount of EMCs on a dollar-for-dollar basis. Parties predict that EMCs will total approximately $32.5 million from 1997 - 2001.

In A.98-01-014, SDG&E's distribution PBR proceeding, SDG&E and various parties agreed in a settlement agreement related to SDG&E's 1999 cost of service study, that certain specified costs should be considered for recovery in this proceeding. The settling parties to this proceeding agree that these costs are reflected in the IMCs and are recoverable. Parties further agree that the cost recovery mechanism for IMCs should continue through the later of the end of 2002 or the Commission's resolution of SDG&E's next cost of service study, to be filed no later than December 21, 2001.

The settling parties propose that SDG&E file an annual advice letter to establish the rate recovery for the IMC and EMC revenue requirements. The parties state that these costs, except for those costs covered by the ISO grid management charge, are not currently recovered in SDG&E's rates and are not to be included in SDG&E's distribution rate. SDG&E proposes establishing a Consolidated Restructuring and Section 376 account, with subaccounts of Internally Managed Cost Account (IMCA) and Externally Managed Cost Balancing Account (EMCBA). The settlement proposes that separate rate components be set annually through the end of 2002 for the IMCA revenue requirement and through the end of 2001 based initially on the EMCBA revenue requirement, which represents a forecast of projected EMCs not recovered elsewhere in FERC or Commission rates. If SDG&E's request to establish a TRA is approved in the RAP proceeding (A.98-07-006, *et al.*), the total of the billed revenues recorded in the Consolidated Restructuring and Section 376 Account will be transferred to the TRA.

On a monthly basis, SDG&E proposes to compare billed revenues from the EMC rate component to actual EMCs. Any over- or under-collection resulting from this comparison will be reflected in the subsequent year's EMC rate component and would receive the three-month commercial paper interest rate. The rate set to cover EMCs and IMCs for calendar year 1999 would recover EMCs forecasted for 1999 as well as recorded costs for 1997 and 1998. The parties also agree that the methodology for determining revenue fluctuations due to sales will be consistent with the methodology adopted in D.98-12-038 regarding SDG&E's cost of service settlement in A.98-01-014.

The settlement proposes that SDG&E track the total amount of EMCs and 376 IMCs in a new "Competition Transition Charge (CTC) Displacement Tracking Account" and to compare the total to the TCBA to evaluate SDG&E's reduced opportunity to recover its transition costs.

The EMCs are not subject to further reasonableness reviews. SDG&E agrees to track its IMCs during the transition period until such time as ORA indicates to SDG&E that such tracking is no longer necessary. However, the IMCs are not subject to further review, investigation, and adjustment.

The settlement also defines "substantial future regulatorily required restructuring costs" as those costs for new restructuring-related programs that represent a substantial departure from the current restructuring-related programs. These costs would be imposed by either a FERC or Commission decision and must amount to costs of $1 million or more in annual revenue requirements for programs lasting longer than one year, or $2 million or more in revenue requirements for a single "restructuring-related, ISO, or PX program." (SDG&E settlement, p. 8.)

TURN's Position

TURN does not necessarily oppose adoption of PG&E's settlement as long as two issues of concern are satisfactorily resolved and TURN's proposed conditions are adopted. TURN recommends that Commission policy should be consistent across utilities in the same industry, especially where the Commission is implementing a specific statute. "The resolution of common policy and legal issues must be consistent across utilities, regardless of whether their individual cases are litigated or settled. To act otherwise would open up the Commission to justifiable criticism that its decisionmaking is unpredictable, unfair, and even arbitrary." (TURN's opening brief, p.1.) TURN advocates that the same principles it recommends applying to Edison should also be adopted for PG&E and SDG&E. TURN recommends that these principles be adopted in conjunction with PG&E's settlement, if that approval is conditioned as TURN recommends.

TURN's comments relate to where and how costs potentially eligible for § 376 treatment should be reviewed and recovered. TURN has recommended both in this proceeding and in PG&E's general rate case (GRC) application (A.97-12-020) that costs associated with the implementation of direct access, the ISO, and the PX should not be included in base rates for test year 1999.

In PG&E's testimony in this proceeding, PG&E stated that:

> "PG&E will incur costs related to the continuous maintenance and operation of a new system or function that was required by electric industry restructuring. PG&E believes it is appropriate to recover through GRC-authorized base revenues such expenses associated with any new system or modification necessary to implement restructuring. Also, the annual revenue requirement for the capitalized portion of any new system or modification required by restructuring would be recovered through GRC-authorized base revenues. This is consistent with traditional treatment of costs necessary to provide service to PG&E's electric retail customers." (Exhibit 54, p.1-18)

In contrast, TURN contends that restructuring implementation costs must not become part of distribution base rates, must be limited to actual costs incurred, and must be subject to after-the-fact reasonableness review. TURN recommends that the principles established for § 376 eligibility and recovery should apply to all of the utilities, whether they have entered into a settlement or not. TURN argues that restructuring implementation costs should be declared to be eligible for § 376 recovery or not recovered in monopoly rates at all. TURN maintains that these costs are largely not under the control of utilities and are not readily predictable; therefore, if these costs are included in base rates or distribution PBR, forecasts will be overestimated. In addition, TURN states that including capital costs in rate base will artificially inflate the distribution rate base. TURN urges that we reject PG&E's proposal to include restructuring implementation costs in base revenues in the GRC, because these costs are very different from the ongoing provision of utility electric services. PG&E has described these activities as related to "new responsibilities [that] are still being developed in the direct access proceeding, and once determined, are likely to evolve over time." (Exhibit 2, p.2-8 in A.97-12-020.) TURN recognizes that such uncertainty increases the difficulty of accurately forecasting future ongoing costs and states that because there is a significant risk of guessing wrong, use of the traditional GRC forecast process would encourage high estimates of these cost elements.

TURN also contends that use of the ERCA to record any unanticipated costs arising from unanticipated implementation activities is inappropriate. TURN believes that ERCA represents an underlying shifting of the risks of cost recovery, because no mechanism exists for any other area of utility activity where costs of that activity were included in setting the utility's base revenues. TURN argues that PG&E is seeking to retain a safety net by including these costs in forecast ratemaking.

All parties agree that in order to be eligible for recovery under § 376, the recovery of approved restructuring implementation costs must delay the recovery of transition costs beyond the end of the transition period. TURN recommends that the following additional principles be adopted for PG&E, Edison, and SDG&E:

1. Identification and recovery of all restructuring implementation costs should be addressed in this proceeding. Implementation costs should not be included in distribution rates or distribution PBR mechanisms.

2. An arbitrary cut-off date for implementation should not be imposed. Such an approach would lead to costs being recovered in another forum where they would be recovered based on dubious forecasts and would result in ratepayers overpaying.

3. Restructuring implementation costs should be recorded in a memorandum or balancing account as incurred and then reviewed for reasonableness. Such costs should not be recovered on a forecast basis because of the uncertainty of the future level of these costs.

4. The Commission should retain an independent auditor to conduct an ongoing review of the implementation costs, addressing the accuracy of the accounting and whether such costs are prudently incurred.

5. The costs of implementing revenue cycle services should not be automatically excluded from § 376 eligibility.

6. Costs eligible for § 376 treatment must be incremental to costs already reflected in base rates. Any savings associated with net staff reductions, more efficient systems, or discontinued activities that result from restructuring implementation should be recognized and should offset such costs.

7. Capital-related restructuring implementation costs should be amortized over the remainder of the transition period at the utility's reduced transition cost rate of return and should not be included in distribution rates either before or after 2001.

8. All generation-related costs should be recovered through spin-off or divestiture of generation assets or as going forward costs, but not given § 376 treatment.

9. PX start-up and development costs are eligible for § 376 treatment, as are the utilities' costs of developing systems to bid default customer load into the PX. All customers should pay for these costs. Ongoing costs of PX operation and utility load bidding functions should not be so eligible.

10. No recovery should be allowed which imposes costs on retail ratepayers associated with the utilities' wholesale contract responsibilities.

11. No recovery of costs should be allowed under § 376 until it is determined, that these costs will not be recovered through some other mechanism, e.g., FERC-approved rates or directly from customers.

12. Section 376-eligible costs should be recovered from all customers, regardless of their procurement choice, absent some compelling evidence to the contrary.

13. Restructuring implementation costs should be recovered through a debit entry to the TRA and should not be functionalized into separate cost categories such as transmission, distribution, etc.

Enron's Position

Enron believes functionalization, or cost assignment to particular services or function, is necessary to facilitate continued restructuring efforts. Enron recommends that this approach would assist in the transition to competitive markets, prevent subsidization of utility-offered competitive and potentially competitive services by captive ratepayers, and ensure that alternate service providers have the ability to compete with the utilities in the provision of competitive services. Because neither the PG&E nor the SDG&E settlement recommends functionalization of restructuring implementation costs, Enron recommends that the settlements be rejected, in part.

Enron contends that because the implementation costs are associated with the functions of distribution, transmission, generation, and procurement, the costs must be identified with the service for which they were incurred and recovered through that service. Enron asserts that Commission policy requires functionalization. In D.96-10-074, we ordered the UDCs to separate their most recent authorized rate base and revenue requirements into the functions of generation, transmission, and distribution. This was confirmed in D.97-08-056, in which we also ordered that costs be separated into nuclear decommissioning and public purpose programs.

Enron disputes PG&E's recovery of IMCs through a one-time debit to the TRA and recovery of approved EMCs through monthly debits to the TRA. Enron believes this recovery mechanism results in recovery of costs which runs counter to established policy favoring unbundling of costs for recovery in order to facilitate efficient markets and customer choice.

Similarly, Enron contends that SDG&E's cost recovery mechanism does not reflect established Commission policy. SDG&E proposes to establish two separate rate components based on IMC and EMC revenue requirements, to be set annually and to remain in effect through the end of the year 2002 (IMC) and 2001 (EMC). These separate rate components will be assessed on all customers for recovery and, therefore, Enron contends that this settlement does not comply with Commission policy. The revenue requirements for these rate components would be subtracted from total billed revenues prior to the determination of CTC residual revenues.

Enron also contends that SDG&E's proposed recovery of IMCs raises issues of statutory interpretation, because the proposed settlement provides for recovery of IMCs in part on a forecasted basis. Thus, it is not clear that the costs have met the § 376 hurdle of being funded by an electrical corporation. The settlement's proposed recovery of EMCs may lead to double recovery because of the inclusion of start-up and development portion of the ISO grid management charge. Enron believes this charge is already recovered as average PX revenues in the PX charge assessed to SDG&E's bundled service customers.

Enron proposes that its functionalization proposal be reflected in customers' rates by increasing the PX credit for 1997 and 1998 costs for the procurement function. Enron believes this true-up would be similar to the true-up to the PX charge or credit currently calculated by the UDCs in order to correct inaccuracies. Enron contends that the absence of language regarding functionalization in § 376 does not preclude such a means of recovery. Moreover, Enron argues that its position in the RAP pertains solely to procurement costs, particularly which procurement costs currently embedded in the UDCs' rates as well as ongoing costs of procurement should be reflected in the PX credit. Enron explains that its proposal in the RAP does not address the other five functional categories it has developed here for the UDCs' restructuring implementation costs.

Edison's Position

Edison's briefs are limited to one issue: ORA's benchmarking proposal for reasonableness reviews as described in Exhibit 34. In that proposal, ORA recommends that, to determine reasonable forecasts of future costs, each utility be required to provide data in a common format and to provide testimony comparing itself to the other two utilities and explaining why it was necessary to exceed the lowest-cost utility in three program areas: direct access implementation, hourly interval meters, and billing system modifications. Edison disputes the efficacy of this proposal and believes it is unworkable. ORA recommends that Edison's brief be accorded no weight, as the issue was fully litigated in Phase 1 of the Edison phase of this proceeding.

Because we have determined that 1) implementation is limited to 1997 and 1998 costs and 2) implementation costs not allowed § 376 treatment and associated cost recovery are not recoverable from ratepayers in any other form, the issue of future proceedings is moot.

Discussion

Rule 51.1(e) provides that the Commission must find a settlement "reasonable in light of the whole record, consistent with the law, and in the public interest" in order to approve the settlement. These are the criteria that we must apply to the settlements before us.

In D 92-12-019, we set forth criteria by which we would consider an all-party settlement. The first criterion is that the settlement must enjoy "the unanimous sponsorship of all active parties to the instant proceeding." All active parties in this proceeding do not sponsor the settlements; therefore, we need not address the other criteria set forth in D 92-12-019. We will consider the settlements under the criteria set forth in Rule 51.1(e). This is a more stringent standard of review, as we have recognized in previous decisions:

> "However, the standard of review here is somewhat more stringent. Here, we consider whether the settlement taken as a whole is in the public interest. In so doing, we consider individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law." (D 96-01-011, 64 CPUC2d, 241, 267, citing D 94-04-088.)

We do not believe that the settlements before us are reasonable in light of the whole record, consistent with the law, and in the public interest. In the accompanying decision in this docket we have established various principles regarding Edison's implementation costs to guide our consideration of the eligibility of costs for § 376 treatment. We agree with TURN that Commission policy should be consistent across utilities in the same industry, particularly in these proceedings where we are implementing a specific statute. It would not be reasonable to adopt particular standards for Edison but different standards for PG&E and SDG&E. These applications were consolidated because they address similar issues of policy and law.

Therefore, we will discuss the policies guiding our consideration of the principles established for considering costs for § 376 treatment. We will then discuss the reasonableness of the proposed settlements in light of these principles. Finally, we discuss the aspects of the settlements that comply with our principles. This decision provides guidance to the parties regarding our expectations for resolving settlement issues.

Pursuant to Rule 51.7, we invite the parties to renegotiate the settlement terms which we have found are not in the public interest and ensure that the proposed settlements are consistent with our adopted guidelines. We agree with parties that the externally managed restructuring costs should be recovered on a recorded, as incurred basis, because such costs will either be reviewed by FERC or have been deemed reasonable by this Commission.[3] If such renegotiations fail, parties should propose alternative relief.

[3] For the Consumer Education Program, an Assigned Commissioners' Ruling issued on September 14, 1998 in R.94-04-031/I.94-04-032 determined that no further proceedings were necessary with respect to the disallowance mechanism provided for in D.94-08-064, because the aided awareness target of 60% for the total of all target audiences was met.

Implementation of the new market structure has occurred as of December 31, 1998

Defining implementation for purposes of § 376 treatment is a pivotal determination in establishing our principles for cost eligibility. This determination has crucial ramifications for § 376 eligibility, and by extension, cost recovery and impacts on the competitive market.

We find that implementation of programs to accommodate direct access, the ISO, and the PX that are eligible for § 376 treatment are the reasonable and necessary costs incurred for such programs as of December 31, 1998. Section 376 does not define implementation and we cannot find that implementation and the transition period are one and the same. Since the Legislature determined the length of the transition period and was aware of the residual nature of CTC recovery, the Legislature could easily have prescribed that the implementation period was the same as the transition period. It did not do so. As we have previously determined in D 97-12-042, because the costs of establishing the infrastructure underlying the new market structure were not included in rates as of June 10, 1996, the Legislature provided an opportunity for the utilities to be made whole in terms of transition cost recovery.

Defining implementation in this manner ensures that we are properly considering the intent of § 376, as we discussed in D 97-12-042. The Legislature determined that there were certain costs to be expended on new programs to implement the PX, the ISO, and direct access. The Legislature afforded the utilities the opportunity to recover assets that might become uneconomic in the new competitive generation market by providing for a rate freeze and subsequent recovery of such transition costs during the transition period. It would be inequitable to require that these new programs be established and provide the opportunity for full transition cost recovery, without providing for some mechanism to ensure that the costs of implementing the new programs do not interfere with transition cost recovery:

> "The Legislature was aware of the residual nature of the CTC and recognized that the size of the CTC would be affected by the levels of the other rate components. Because the total rate is frozen, the portion of the rate available to offset transition costs, the CTC, decreases as other components increase. The consequence of a lower CTC is a slower pace of recovery of the utilities' uneconomic costs.
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> "Seen in this light, it becomes clear why the Legislature provided for special treatment for the 'costs of programs to accommodate implementation of direct access, the Power Exchange, and the Independent System Operator.' These are three new major programs that we created to carry out our plan for industry restructuring, described in our Preferred Policy Decision (D 95-12-063, as modified by D 96-01-009). The Commission required the utilities to bear actual or potential additional costs to implement these new programs. None of these additional costs were reflected in the frozen rates, and recovery of these costs during the transition period would necessarily displace other cost recovery. The residual nature of the CTC meant that recovery of these implementation costs jeopardized the Legislative plan for offsetting the utilities' uneconomic costs.
>
> "The solution codified in § 376 is to allow the utilities to recover the implementation costs they incur but in effect to extend the period for recovery of uneconomic costs to the extent necessary to restore the balance of risks of the initial concept of cost recovery. Utilities remain at risk for recovering their uneconomic costs during the transition period, but that risk is not increased by FERC- or Commission-authorized recovery of implementation costs." (D 97-12-042, mimeo. at p. 5.)

Approved implementation costs displace headroom and have the potential to significantly lengthen transition cost recovery and thus impact the onset of competition. As we have previously stated, an important goal of electric restructuring is to protect competition - not individual competitors. No greater competitive advantage should be afforded the incumbent utilities than any other competitor in the new market. (D.97-11-074, mimeo. at p. 50.) In fact, since March 31, 1998, the ISO has been managing the power grid that is under its control, consumers are opting to purchase electricity through direct access, and the utilities have procured energy through the PX. Allowing § 376 treatment for the costs of implementation of such programs as of year-end 1998 is generous, but provides for necessary post-operation experience and modifications.

Eligible restructuring implementation costs must receive § 376 treatment; they are otherwise not recoverable from ratepayers

Costs incurred by PG&E or SDG&E that are not spent on approved implementation activities, as defined in this decision, should not be recoverable from ratepayers in any other form. We must carefully evaluate costs to determine if the utilities incurred particular costs to 1) establish the new market structure as of December 31, 1998, i.e., accommodate the implementation of the ISO, the PX, and direct access, 2) operate as a distribution utility, or 3) allow the utility to operate as a competitor in the new market structure.

We agree with TURN that these costs should not be included in distribution base rates. Because we authorize implementation costs only for 1997 and 1998, the issue of recovering internally managed costs in PG&E's GRC becomes moot. Contrary to PG&E's belief, it is not appropriate to recover through GRC-authorized base revenues the expenses associated with any new system or modification necessary to implement restructuring. These are not distribution costs and should not be included in distribution rates. Recovery of implementation costs is limited to those incurred in 1997 and 1998, consistent with our adopted guidelines. We will not treat the general category of restructuring costs in the same manner as distribution costs. These costs relate to activities that are very different from the ongoing provision of electric services.

Under a traditional rate case approach, shareholders are protected if costs are less than anticipated because shareholders reap the benefits of savings between rate cases. However, in return, shareholders should also bear the burden of additional expenses incurred during a rate case cycle. (D.96-12-066, mimeo. at p. 4.) Allowing such recovery through distribution rates or a distribution PBR would allow cross-subsidization and impede competition.

This is particularly important since PG&E's distribution revenue requirement will be used to develop a distribution PBR (A.98-11-023). When we adopted PBR as a preferred ratemaking methodology to cost-plus regulation, we broke the link between costs and rates. In doing so, we recognized that the tasks and functions of the utility distribution company are not static, but will change over time. In addition, by adopting PBR regulation, we explicitly expect that productivity will increase and that the utility will achieve significant cost efficiencies. We will not now go back to a form of cost-plus regulation by allowing the utility to recover costs associated with operating in the new market in the PBR. Allowing recovery for such costs via the PBR would skew PBR incentives. While we may be excluding various costs from § 376 treatment, they cannot be recategorized as distribution costs and therefore cannot be recovered in base rates or through the PBR mechanism.

We recognize that significant costs may be incurred to operate in the new market structure. Neither this Commission nor the Legislature contemplated that the costs of competing in the new competitive generation marketplace would be recovered from existing ratepayers. These costs must be recovered from market revenues, not from ratepayers. Such costs must be carefully evaluated to determine if other market competitors must incur similar costs associated with various activities. If so, these activities are required to function in the new marketplace. The associated costs are simply a cost of operating in that competitive market and must be recovered from market revenues. To determine otherwise would harm competition because monopoly distribution rates would subsidize costs of competing in the new market.

Only Incremental Costs May Receive § 376 Treatment

All parties agree that costs eligible for § 376 treatment must be incremental to those costs covered in current rates. These costs must also be incremental to those costs that relate to ongoing utility business. Neither PG&E nor SDG&E should seek to recover such costs as employee transition costs, to the extent personnel who would otherwise have worked on discontinued functions staff new activities.

Avoided Costs and Associated Cost Savings Must be Considered in Approving Reasonableness of Costs

Certain features of implementation may reduce costs for the utilities. It is reasonable to incorporate these avoided costs and any associated cost savings into a final determination of costs receiving § 376 treatment. We direct PG&E, SDG&E, and parties to their respective settlement agreements to consider this principle in renegotiating the settlements.

Costs will not be given § 376 treatment if it is determined that those costs will be recovered from customers in another way

Only those costs not recovered in any other way will receive § 376 treatment. To the extent such costs are recovered in FERC-approved rates, are reimbursed through the ISO and the PX, or are recovered directly from customers through fees, there is no need to allow such costs to also receive § 376 treatment.[4]

Costs categorized as eligible for § 376 treatment benefit all customers and must be paid for by all customers

We have long held to the standard that the purchaser or user of a service should bear responsibility for those costs. We have consistently recognized the importance of providing accurate price signals, and pricing based on the principle of cost causation. (D 97-04-082 mimeo. at p. 123.) Similarly, all customers must pay for costs that benefit all customers. (D 97-12-112, mimeo. at p. 14.) We adopt these principles for costs receiving § 376 treatment. To the extent that all customers benefit from establishing the new market structure, all customers must pay. If only certain customers benefit from a particular service, those customers must bear responsibility for those costs.

As proposed by Enron, functionalization can be defined as cost assignment by service or program, which can be distinguished from cost allocation. Cost allocation assigns cost responsibility by customer group. As we determined in our accompanying decision in this docket, we will not further functionalize restructuring implementation costs at this time. We have adopted stringent criteria for allowing § 376 treatment of restructuring implementation costs. As delineated herein, these costs have been incurred to create the new market structure. All customers, whether bundled or direct access, benefit from the

[4] We will not address the issue of fees for DASR processing or fees for discretionary services. Pursuant to an Assigned Commissioner's Ruling issued on February 5, 1999, in R 94-04-031/I 94-04-032, PG&E, Edison, and SDG&E are ordered to file applications on April 30, 1999 to address such fees.

creation of the new competitive regime and therefore, consistent with cost causation principles, must bear the burden of these costs.

Eligible costs should be recovered through the TRA or similar ratemaking mechanism

D.97-12-042 allowed the utilities to establish a tracking account for costs deemed eligible for § 376 treatment.

> "When eligible costs are recovered (*i.e.*, when collected revenues are allocated to offset eligible costs), the affected utility should record the amount recovered in a tracking account. When we approach the end of the transition period, we will determine whether and to what extent collection of the CTC should be continued past December 31, 2001 to compensate for the reduced opportunity to recover uneconomic costs. [footnote omitted] Obviously, § 376 comes into play only if uneconomic costs are not fully recovered by December 31, 2001."

PG&E's request to recover eligible costs in the TRA is reasonable. However, we do not agree that it is necessary to establish the proposed ERCA account. Given our adopted guidelines in this proceeding, there is no need to track IMCs beyond 1998. Therefore, PG&E's cost recovery mechanism must be revised in order to be consistent with our adopted guidelines.

Should SDG&E be granted its request to establish a TRA in the RAP, SDG&E should recover eligible implementation costs in the same fashion as Edison. SDG&E's settlement proposal must be revised to be consistent with our guidelines for cost recovery for eligible costs for 1997 and 1998.

Both PG&E and SDG&E should record these § 376-eligible costs in a memorandum account to compare with transition cost recovery as we draw closer to the end of the rate freeze. We will develop a methodology to compare these costs and the necessity for extending CTC in A.99-01-016, *et al.*, the proceedings we have established to review post rate freeze ratemaking methodology. As we discuss below, § 376 treatment will not be triggered for SDG&E.

Once final costs are approved for § 376 treatment, headroom revenues should be allocated to these costs according to the principles established in the RAP, A 98-07-006, *et al.* Costs related to restructuring activities that are not eligible for § 376 treatment cannot be recovered from ratepayers, as discussed above, and shall not be recorded in any accounts that result in ratepayer funding of these costs.

Eligible capital costs should be treated as expensed items for ratemaking purposes

To the extent capital costs are found reasonable and approved for recovery in Phase 2, we must determine how these costs should be amortized. In our accompanying decision, we determined that because capital costs have been incurred to accommodate implementation as of December 31, 1998, they should be treated as expensed items for ratemaking purposes, which is consistent with both tax and accounting practices. It is incumbent upon the utility to delineate the costs of such capital projects between those costs eligible for § 376 treatment and those costs not so eligible. Since we granted § 376 treatment only to those costs incurred in 1997 and 1998, we required Edison to expense these items for ratemaking purposes. This means that these costs need not be grossed up for return and tax purposes.

Adopted Guidelines

In the accompanying decision in this docket that considers Edison's implementation costs, we have adopted the following guidelines regarding § 376 treatment and cost recovery:

1. Identification and recovery of all restructuring implementation costs shall be addressed in this proceeding. Implementation costs shall not be included in distribution rates or distribution PBR mechanisms.

2. Only those costs incurred to establish the ISO, PX, and direct access shall be determined to be recoverable as costs to accommodate implementation and receive § 376 treatment. Therefore, costs incurred after 1998 are not eligible for § 376 treatment and the costs of operating these programs on an ongoing basis are not eligible for § 376 treatment.

3. Eligible 1997 and 1998 implementation costs for direct access shall be reviewed for reasonableness. Costs incurred for the start-up and development of the ISO, the PX, the CEP, and the EET need no further reasonableness review.

4. The costs of implementing revenue cycle services are not eligible for § 376 treatment.

5. Costs eligible for § 376 treatment must be incremental to costs already reflected in base rates. Any avoided costs or any savings associated with net staff reductions, more efficient systems, or discontinued activities that result from restructuring implementation shall be recognized and must offset such costs.

6. All customers benefit from establishing the new market structure, therefore all customers must pay for these costs. Section 376-eligible costs shall be recovered from all customers, regardless of their procurement choice.

7. Capital-related restructuring implementation costs shall be recovered as expensed items for ratemaking purposes and shall not be grossed up for return or taxes.

8. All generation-related costs should be recovered through spin-off or divestiture of generation assets or as going forward costs, but shall not be given § 376 treatment.

9. Costs expended on implementation activities that would allow the utilities a competitive advantage in the new market shall not be allowed recovery from other than market revenues.

10. PX start-up and development costs are eligible for § 376 treatment, as are the utilities' costs of developing systems to bid default customer load into the PX. All customers should pay for these costs. Ongoing costs of PX operation and utility load bidding functions shall not be so eligible and must be recovered from market revenues.

11. No § 376 treatment and no recovery shall be allowed which imposes costs on retail ratepayers associated with the utilities' wholesale contract responsibilities.

12. No recovery of costs shall be allowed under § 376 until it is determined that these costs will not be recovered through some other mechanism, e.g., FERC-approved rates or directly from customers (for instance, in fees for discretionary services).

13. Restructuring implementation costs shall be recovered through a debit entry to the TRA and shall not be assigned to separate cost categories such as transmission, distribution, etc.

Proposed Settlements and Conformance with Adopted Guidelines

In this section, we address the proposed settlements and consider whether these proposed agreements conform to our adopted guidelines. The externally managed costs that are discussed in both PG&E's and SDG&E's settlements allow § 376 treatment and cost recovery for ISO and PX start-up and development costs, CEP costs, and EET costs. This approach is consistent with the guidelines and principles that we have adopted for Edison. We determined that these costs are eligible for § 376 cost recovery, and should be presumed reasonable.

Consistent with the proposed settlements, we agree that PG&E's and SDG&E's shares of both the ISO and PX start-up and development costs are eligible for § 376 treatment. Pursuant to D.97-12-042 and D.98-12-027, we have determined that these costs are eligible for § 376 treatment, whether assessed as a one-time charge or as a volumetric charge. Moreover, funding of these costs has been defined to occur regardless of when the contribution to the development costs is made. We have confirmed that the term "funded" does not imply a specific time when costs are paid for, nor is there a requirement that the financial contribution take place through specific mechanisms. (D.98-12-027, mimeo. at p. 11.)

Costs associated with the PX's start-up and development are assessed through the Initial Charge. The costs associated with the ISO's start-up and development are assessed through the Grid Management Charge. Costs associated with the ISO and PX start-up and development must be incurred by year-end 1998, but payments made by PG&E and SDG&E can be made after 1998, to the extent these occur. These payments to the ISO and PX are not assessed to any market competitor, other than PG&E, Edison, and SDG&E.

In D.97-03-069, we approved the Consumer Education Program (CEP) to be funded by PG&E, Edison, and SDG&E. The October 30, 1996 Direct Access Working Group (DAWG) Report recommended that utilities be permitted to recover their costs associated with the development and implementation of the CEP. This report stated that such funding was consistent with § 376. We adopted this recommendation and determined that funding requirements for the joint CEP would be allocated among PG&E, Edison, and SDG&E in proportion to each utility's share of actual 1996 sales. We authorized these utilities to establish memorandum accounts under IRMA to track these expenditures. We concluded that the CEP efforts were critical to direct access implementation in order to educate residential and small commercial customers about choices involved in the new market structure and to overcome the mindset of dealing only with the incumbent monopoly utility.

We therefore determined that these costs are recoverable from their customers pursuant to § 376, but left the details of this recovery to other proceedings. A total amount of $23 million was authorized for all three utilities for the joint CEP effort. In D 97-08-064, we authorized a total budget for the joint CEP, Commission outreach activities, and community-based education and outreach activities of $89.3 million (of which $23 million was previously authorized). The utilities' budget for the joint CEP efforts was not to exceed $74.5 million, with Commission and community-based outreach not to exceed $15.8 million. The consumer education program is required by statute (see § 392(b))[5] and we affirm that the costs of the CEP program are eligible for § 376 treatment. Again, PG&E, Edison, and SDG&E are required to fund this program and no other market participant expends costs for this program.

We made similar determinations for the Electric Education Trust (EET) for consumer education activities to take place after the CEP effort concluded. The role of the EET is to promote consumer education in helping customers to understand the changes to the electric industry during the transition period to direct access. We determined that the EET should have a limited lifespan and

[5] Section 392(b) requires that the electric corporations, in conjunction with and subject to the approval of this Commission, implement a consumer education program prior to the implementation of the CTC.

should sunset as of June 30, 1999 unless extended by the Commission or by statute. (D 97-03-069, mimeo. at p. 39.)

After considering various funding options, we determined that public policy would best be served by considering the EET to be part of the implementation costs associated with direct access. We authorized an initial amount of $3 million, to be recoverable from ratepayers pursuant to § 376. In D 98-07-098, we extended the life of the EET to December 31, 2001, pursuant to SB 477 (Stats. 1997, Ch. 275, Section 31). In D 98-12-085, we adopted the recommendation to extend the EET's funding to cover the life of the EET until its scheduled termination date of December 31, 2001. A total of $13.1 million has been allocated for EET funding through 2001, which consists of a $3.1 million education plan and a $10 million community-based organization outreach plan.

These funds were allocated under the same terms and conditions as the original funding and therefore EET costs are eligible for § 376 treatment. This is not inconsistent with our adopted policy, because, similar to funding for the ISO and PX start-up and development, the costs are required by statute and the obligation has been established prior to year-end 1998.

Therefore, we find that the it is appropriate to grant cost recovery and § 376 treatment for the EMC costs identified in both the PG&E and SDG&E settlements. This aspect of both settlements conforms to our adopted guidelines.

The IMC costs recommended for § 376 treatment in the proposed settlements do not comport with our adopted guidelines; nor is the proposed cost recovery of IMCs consistent with those guidelines.

We have adopted guidelines for Edison determining that direct access costs are eligible for § 376 treatment only to the extent these costs are required to implement the program and only through December 31, 1998, with the exception of the uniform node identifier system (UNIS) costs.

In D 97-05-040, we adopted implementation procedures regarding direct access. In this decision, we addressed fundamental procedures and rules to be in place for the provision of direct access. We determined that the availability of direct access mitigated the exercise of market power in the PX and that no technical or operational constraints barred direct access. (D 97-05-040, mimeo. at pp. 15, 18-19.) Therefore, we implemented direct access for all customers as of January 1, 1998, and recognized that the market itself would allow for a gradual development of an interest in customer choice. Of course, as circumstances dictated, the ISO and the PX were not functional until March 31, 1998; therefore, direct access was not initiated until that date.[6] Therefore, all of the elements necessary to allow customer choice were in place as of January 1, 1998, although direct access itself did not begin until March 31, 1998, simultaneously with the implementation of the ISO and the PX.

In D 97-05-040, we observed that PG&E, Edison, and SDG&E had not provided a comprehensive scope of the costs they proposed to include as direct access implementation costs. PG&E and Edison commented that these activities would include, but would not be limited to, consumer education and protection efforts, customer information costs, UDC systems development, implementation, and testing for new capabilities required to interface with the ISO, the PX, and others, installation and reading of real-time pricing meters, UDC billing system modifications required to interface with the ISO, Power Exchange, and others.

We determined that these cost categories were too broad to distinguish which specifically could be attributed to implementation of direct access, but

[6] See D 97-12-031 and Coordinating Commissioner's Ruling in R 94-04-031/I 94-04-032, dated March 30, 1998.

allowed the utilities to track these costs. We directed the utilities to establish memorandum subaccounts to track these costs. We did not guarantee recovery of such costs, but left it to other proceedings to establish procedures to examine whether these tracked costs should be recovered, the reasonableness of these costs, and the recovery of such costs.

In our accompanying decision regarding Edison's implementation costs, we determined that only certain costs should be eligible for direct access implementation and will receive § 376 treatment in 1997 and 1998, to the extent these costs are found reasonable. Costs incurred under the guise of implementing direct access, but which are required of all market competitors are not eligible for § 376 treatment. Certain costs must and will be incurred by all market competitors and therefore must be recovered from market revenues.

We have also determined that costs associated with wholesale contract responsibilities are not eligible for § 376 treatment. We will not adopt a settlement that allows the possibility of these costs to be deferred. We agree with TURN that if FERC denies recovery of these costs, we cannot assume that these costs are reasonable for inclusion in wholesale rates. At any rate, given our approach to implementation costs, we do not see how such costs could be presumed to accommodate the implementation of the ISO, the PX, and direct access.

In D 98-11-044, we determined that UNIS costs are eligible for § 376 treatment. We concluded that the reasonable costs of such expenditures are recoverable from ratepayers and should receive § 376 treatment, because the costs are being incurred to implement direct access. In D 97-12-090, which set up this working group, we stated that we agreed with the California Energy Commission and Enron that 1998 provided a window of opportunity to adopt and implement such a numbering system. At that time, we hoped that a decision could be adopted in March 1998. Events, unfortunately, overtook this decision. Therefore, we must find that the UNIS costs can be determined to be eligible for § 376 recovery only through December 31, 1999. This is the one exception to our general principles.

Voluntary Cap

Both settlements propose a voluntary cap on the amounts that will be eligible for transition cost recovery after the transition period. Because we have defined implementation narrowly, consistent with the mandate of § 376, we stated that the need for Edison's voluntary cap is greatly diminished. We will not make such a determination here, but will leave it to the renegotiations of the parties to determine if a cap is still necessary.

Impact of A.99-02-029

On February 19, SDG&E filed A.99-02-029, informing the Commission that it expects to have completed full recovery of Commission-authorized costs for utility generation-related assets and obligations as early as June 30, 1999, thereby meeting the statutory condition for termination of its electric rate freeze. For SDG&E, it is clear that none of the restructuring implementation costs need be given § 376 treatment, i.e., recovery of these costs obviously will not displace recovery of generation-related transition costs. However, cost recovery is still an issue to be determined in this proceeding. Any renegotiated settlement must be consistent with the cost recovery principles adopted for Edison and the guidance provided in this decision.

Parties may renegotiate the terms of the settlements or request alternative relief

In this decision, we adopt guidelines for costs eligible for § 376 treatment and cost recovery. We will allow PG&E and SDG&E 30 days from the effective date of this decision to renegotiate their settlements, consistent with the guidelines adopted herein. If they accept these guidelines, PG&E and SDG&E should notice settlement conferences and submit revised settlements consistent with our policies. Other parties may comment on the revised settlements 15 days after they are filed. If PG&E or SDG&E do not renegotiate the settlements, each utility must request alternative relief.

Findings of Fact

1. Because the costs of establishing the infrastructure underlying the new market structure were not included in rates as of June 10, 1996, the Legislature provided an opportunity for the utilities to be made whole in terms of transition cost recovery.

2. In A.98-05-004 and A.98-05-006, PG&E and SDG&E, respectively, seek to establish the eligibility of particular cost categories for which § 376 treatment is appropriate and the applicable ratemaking and rate recovery mechanisms.

3. On November 13, 1998, PG&E and various parties filed a Motion for Approval of Settlement that would resolve Phase 1 and Phase 2 reasonableness issues in this proceeding.

4. On November 12, 1998, SDG&E and various parties filed a Motion for Adoption of Settlement that would resolve Phase 1 and Phase 2 reasonableness issues in this proceeding.

5. Both proposed settlements would separate costs into externally managed restructuring costs and internally managed restructuring costs.

6. Externally managed restructuring costs consist of FERC-approved ISO and PX start-up and development costs and Commission-approved Consumer Education Program and Electric Education Trust costs.

7. PG&E's internally managed costs consist of the costs of direct access implementation and demand PX bidding and settlement systems.

8. PG&E's settlement proposes that only externally managed costs are eligible for § 376 treatment. PG&E agrees to cap this treatment at $95 million.

9. PG&E proposes to waive § 376 treatment for all internally managed implementation costs, including those costs requested in the 1999 GRC proceeding, A 97-12-020.

10. Parties agree that PG&E's 1997 and 1998 internally managed costs are recoverable through the TRA and cap this amount at $41.3 million.

11. PG&E's settlement recommends establishing the ERCA to allow for the recording and recovery of unanticipated restructuring costs not forecast in the GRC, to track any unrecovered costs associated with PG&E's wholesale contracts that FERC does not allow PG&E to recover from the contract holders, and to require the Commission to consider the costs of new programs before ordering the utilities to incur these costs.

12. SDG&E's settlement defines internally managed costs as direct access implementation costs, PX load bidding and demand settlement costs, ISO/PX interface costs, hourly interval meter installation and reading costs, UDC billing systems modification costs, customer information release system costs, and environmental impact report costs. The settlement proposes to fix the revenue requirement of these costs at $35.7 million, $16.8 million of which would be granted § 376 recovery.

13. D 98-12-038 adopted a cost of service settlement in SDG&E's PBR proceeding, A 98-01-014. Parties propose that costs related to direct access O&M costs and rate base additions, which were deferred to the instant proceeding, be recovered in this proceeding.

14. Parties propose that SDG&E establish separate rate components to recover the IMC and EMC revenue requirements through the end of 2002 and 2001, respectively.

15. TURN conditionally opposes PG&E's settlement, because TURN recommends that costs associated with implementation of direct access, the ISO, and the PX not be included in base rates for test year 1999 and because of the proposed approach to recovery of costs associated with wholesale contracts.

16. TURN also recommends that approval be conditioned upon adopting the same principles for § 376 treatment and cost recovery it advocates for Edison.

17. Enron contests both PG&E's and SDG&E's settlements, because neither settlement includes functionalization of restructuring implementation costs.

18. We adopted guidelines and principles for § 376 treatment and cost recovery in an accompanying decision in this docket.

19. Commission policy should be consistent across utilities in the same industry, particularly where we are implementing a specific statute.

20. We find that implementation of programs to accommodate direct access, the ISO, and the PX that are eligible for § 376 treatment are the reasonable and necessary costs incurred for such programs as of December 31, 1998.

21. Approved implementation costs displace headroom and have the potential to significantly lengthen transition cost recovery and thus impact the onset of competition.

22. Since March 31, 1998, the ISO has managed the power grid that is under its control, the PX has received and awarded bids and developed and mailed invoices, and consumers are opting to purchase electricity through direct access.

23. Allowing implementation of such programs as of year-end 1998 is generous, but allows for necessary post-operation experience and modifications.

24. We will carefully evaluate costs to determine if they were incurred to 1) establish the new market structure as of December 31, 1998, i.e., accommodate the implementation of the ISO, the PX, and direct access, 2) operate the

distribution utility, or 3) allow the utility to operate as a competitor in the new market structure.

25. Costs claimed as restructuring implementation costs that are not eligible for § 376 treatment should not be recategorized as distribution costs and therefore cannot be recovered in base rates or as part of the distribution PBR mechanism.

26. While significant costs may be incurred to operate in the new market structure, these costs must be recovered from market revenues, not from ratepayers.

27. Costs of operating in the new market are costs incurred by other market competitors.

28. Eligible costs that receive § 376 treatment must be incremental to those costs covered in current rates and incremental to those costs that relate to ongoing utility business.

29. It is reasonable to incorporate any avoided costs and associated costs savings into a final determination of costs receiving § 376 treatment.

30. Only those costs not recovered in any other way will receive § 376 treatment.

31. PG&E's and SDG&E's share of both the ISO and PX start-up and development costs are eligible for § 376 treatment.

32. CEP efforts were critical to direct access implementation in order to educate residential and small commercial customers about choices involved in the new market structure and to overcome the mindset of dealing only with the incumbent monopoly utility.

33. The costs of the CEP program are eligible for § 376 treatment.

34. EET costs are eligible for § 376 treatment.

35. In D.97-03-069, we concluded that expenditures incurred by the utilities for purposes of the statewide Consumer Education Program (CEP) should be eligible for § 376 treatment because these costs are necessary to implement direct access.

36. In D.97-08-064, we adopted a final CEP budget of $73.5 million, but linked reasonableness of expenditures to the utilities' success in achieving a goal of 60% awareness of direct access.

37. On September 14, 1998, an Assigned Commissioner's Ruling was issued that determined no further proceedings were necessary, since the CEP achieved the necessary awareness target of 60%.

38. In D.97-03-069, we found that funding the initial level for the Electric Education Trust (EET) by approving § 376 recovery was appropriate.

39. In D.97-08-064, we increased the EET funding level to $13 million.

40. No recovery should be allowed which imposes costs on retail ratepayers associated with the utilities' wholesale contract responsibilities.

41. We implemented direct access for all customers without a phase-in because we determined that no technical or operational constraints existed that would require a phase-in.

42. We recognized that the market itself would allow for a gradual development of an interest in customer choice.

43. Because the ISO and the PX were not functional until March 31, 1998, direct access was not initiated until that date.

44. We adopted guidelines and principles for § 376 treatment and cost recovery in an accompanying decision in this docket.

45. Eligible restructuring implementation costs must receive § 376 treatment and cost recovery. These costs are not otherwise recoverable from ratepayers.

46. Allowing recovery of implementation costs through distribution rates or a distribution PBR would allow cross-subsidization and impede competition.

47. Only incremental costs may receive § 376 treatment.

48. Avoided costs and associated cost savings must be considered in approving reasonableness.

49. Costs will not be given § 376 treatment if it is determined that these costs will be recovered from customers in another way.

50. To the extent that all customers benefit from establishing the new market structure, all customers must pay. If only certain customers benefit from a particular service, those customers must bear responsibility for those costs.

51. As used in this decision, functionalization can be defined as cost assignment by service or program, which can be distinguished from cost allocation, which assigns cost responsibility by customer group.

52. We will not further functionalize restructuring implementation costs at this time.

53. We have adopted stringent criteria for allowing § 376 treatment of restructuring implementation costs and these costs have been incurred to create the new market structure.

54. All customers, whether bundled or direct access, benefit from the creation of the new competitive regime and therefore, consistent with cost causation principles, must bear the burden of these costs.

55. Costs related to restructuring activities that are not eligible for § 376 treatment cannot be recovered from ratepayers and shall not be recorded in any accounts that result in ratepayer funding of these costs.

56. We will develop a methodology to compare these costs and the necessity for extending CTC in A.99-01-016 et al., the proceedings we have established to review post rate freeze ratemaking methodology.

57. Because capital costs have been incurred to accommodate implementation as of December 31, 1998, they should be treated as expensed items for ratemaking purposes.

58. Comparison of costs among utilities is not necessary in reviewing reasonableness of eligible costs.

59. SDG&E's A 99-02-029 informs the Commission that SDG&E's rate freeze is expected to end in June 1999. Therefore, § 376 treatment of these costs is not relevant; however, cost recovery is still an issue to be determined.

Conclusions of Law

1. The settlements before us are not reasonable in light of the whole record, consistent with the law and in the public interest, and should be rejected.

2. These proceedings were consolidated because they address similar issues of fact and law.

3. It is reasonable to adopt the same guidelines for PG&E, Edison, and SDG&E regarding cost recovery and § 376 treatment of implementation costs.

4. Section 376 does not directly authorize recovery of PX and ISO implementation costs, but extends the period for recovery of generation-related plant and regulatory assets to the extent that the opportunity to recover these assets has been reduced by the collection of specified implementation costs.

5. If the utilities fully recover their generation-related transition costs before December 31, 2001, § 376 will never be triggered.

6. Section 376 does not define implementation and we do not find that implementation and the transition period are one and the same.

7. Since the Legislature determined the length of the transition period and was aware of the residual nature of CTC recovery, the Legislature could easily

have prescribed that the implementation period was the same as the transition period, but did not do so.

8. Limiting § 376 treatment to the reasonable costs of implementation of the PX, the ISO, and direct access in 1997 and 1998 ensures that we are properly considering the intent of § 376.

9. The Legislature determined that there were certain costs to be expended on new programs to implement the Power Exchange, the Independent System Operator, and direct access.

10. In §§ 367 and 368, the Legislature afforded the utilities the opportunity to recover assets that might become uneconomic in the new competitive generation market by providing for a rate freeze and subsequent recovery of such transition costs during the transition period.

11. It would be inequitable to require that these new programs be established and provide the opportunity for full transition cost recovery, without providing for some mechanism to ensure that the costs of implementing the new programs do not interfere with transition cost recovery.

12. An important goal of electric restructuring is to protect competition - not individual competitors.

13. Neither this Commission nor the Legislature contemplated that ratepayers would fund recovery of the costs of competing in the new competitive generation marketplace.

14. To allow monopoly distribution rates to subsidize the costs of competing in the new market structure would harm competition.

15. Pursuant to D 97-12-042 and D 98-12-027, we have determined that these costs are eligible for § 376 treatment, whether assessed as a one-time charge or as a volumetric charge.

16. Funding of ISO and PX start-up and development costs has been defined to occur regardless of when the contribution to the development costs is made.

17. In D.98-07-098, we extended the life of the EET to December 31, 2001, pursuant to SB 477 (Stats. 1997, Ch. 275, Section 31). In D.98-12-085, we adopted the recommendation to extend the EET's funding to cover the life of the EET until its scheduled termination date of December 31, 2001.

18. Similar to funding for the ISO and PX start-up and development, the costs are required by statute and the obligation has been established prior to year-end 1998.

19. The proposed settlements' treatment of externally managed costs is consistent with our adopted guidelines.

20. PG&E's proposed settlement's recommendation to recover externally managed costs through the TRA is reasonable.

21. PG&E's proposed ERCA account is not reasonable and should not be adopted.

22. SDG&E's proposed ratemaking for recovery of externally managed costs must conform to the guidelines adopted for cost recovery.

23. In D.97-05-040, we adopted implementation procedures regarding direct access, addressed fundamental procedures and rules to be in place for the provision of direct access, and determined that the availability of direct access mitigated the exercise of market power in the PX.

24. All of the elements necessary to allow customer choice were in place as of January 1, 1998, although direct access itself did not begin until March 31, 1998, simultaneously with the implementation of the ISO and the PX.

25. We did not guarantee recovery of costs when we allowed the utilities to establish memorandum subaccounts in D.97-05-040 to track costs attributed to implementation of direct access.

26. The Legislature not provide for costs incurred by ESPs to be recovered from the general body of incumbent utility ratepayers. Such costs are simply a cost of doing business for the ESP. These costs must be similarly recovered for the UDC.

27. PG&E's proposed treatment of internally managed costs is not consistent with our adopted guidelines, and therefore, its settlement should be rejected.

28. SDG&E's proposed treatment of internally managed costs is not consistent with our adopted guidelines, and therefore, its settlement should be rejected.

29. We have long held to the standard that the purchaser or user of a service should bear responsibility for those costs. Similarly, all customers must pay for costs that benefit all customers. It is reasonable to adopt these principles for costs receiving § 376 treatment.

30. Restructuring implementation costs benefit all customers and must be paid for by all customers. Enron's functionalization proposal should be rejected.

31. Allowing amortization of capital costs over the transition period or beyond would result in intertemporal inequities and incorrect pricing signals.

32. In D 98-11-044, we determined that UNIS costs are eligible for § 376 treatment. These costs should be recoverable in 1999 only.

33. In our accompanying decision regarding Edison's § 376 costs, we have prescribed specific guidelines for § 376 eligibility.

34. Consistent with Rule 51.7, this decision proposes alternative terms to the settlements. Parties may renegotiate the settlements so that they are consistent with the guidelines adopted for Edison and outlined in this decision.

35. This order should be effective today in order to allow renegotiation of the settlements to proceed expeditiously.

INTERIM ORDER

IT IS ORDERED that:

1. The motion of Pacific Gas and Electric Company's (PG&E), the Office of Ratepayer Advocates, California Large Energy Consumers Association, California Manufacturers Association, the Cogeneration Association of California, the Energy Producers and Users Coalition, the University of California, the State University of California, and California Industrial Users for Approval of Settlement Agreement, filed on November 12, 1998, is denied without prejudice to PG&E's ability to file either a renegotiated settlement, consistent with this decision, or a request for alternative relief. Parties may file comments on PG&E's proposal within 45 days of the effective date of this decision.

2. The motion of San Diego Gas & Electric Company (SDG&E), the Office of Ratepayer Advocates, Federal Executive Agencies, California Large Energy Consumers Association, California Manufacturers Association, the Cogeneration Association of California, the Energy Producers and Users Coalition, the University of California, and the State University of California for Adoption of Settlement Agreement on Issues related to San Diego Gas & Electric Company's Application, A.98-05-006, Under Pub. Util. Code § 376, filed on November 12, 1998, is denied without prejudice to SDG&E's ability to file either a renegotiated settlement, consistent with this decision, or a request for alternative relief. Parties may file comments on SDG&E's proposal within 45 days of the effective date of this decision.

3. The renegotiated settlement agreements shall comply with the following guidelines, as adopted for determining eligibility for Pub. Util. Code § 376

treatment of restructuring implementation costs incurred by Southern California Edison Company (Edison):

a. Identification and recovery of all restructuring implementation costs shall be addressed in this proceeding. Implementation costs shall not be included in distribution rates or distribution performance-based ratemaking (PBR) mechanisms.

b. Only those costs incurred to establish the independent system operator (ISO), Power Exchange (PX), and direct access shall be determined to be recoverable as costs to accommodate implementation and receive § 376 treatment. Therefore, costs incurred after 1998 are not eligible for § 376 treatment and the costs of operating these programs on an ongoing basis are not eligible for § 376 treatment.

c. Eligible 1997 and 1998 implementation costs for direct access shall be reviewed for reasonableness. Cost incurred for the start-up and development of the ISO, the PX, the Consumer Education Program, and the Electric Education Trust need no further reasonableness review.

d. The costs of implementing revenue cycle services are not eligible for § 376 treatment.

e. Costs eligible for § 376 treatment must be incremental to costs already reflected in base rates. Any avoided costs or any savings associated with net staff reductions, more efficient systems, or discontinued activities that result from restructuring implementation shall be recognized and must offset such costs.

f. All customers benefit from establishing the new market structure, therefore all customers must pay for these costs. Section 376-eligible costs shall be recovered from all customers, regardless of their procurement choice, absent some compelling evidence to the contrary.

g. Capital-related restructuring implementation costs shall be recovered as expensed items for ratemaking purposes and shall not be grossed up for return or taxes.

h. All generation-related costs should be recovered through spin-off or divestiture of generation assets or as going forward costs, but shall not be given § 376 treatment.

i. Costs expended on implementation activities that would allow the utilities a competitive advantage in the new market shall not be allowed recovery from other than market revenues.

j. PX start-up and development costs are eligible for § 376 treatment, as are the utilities' costs of developing systems to bid default customer load into the PX. All customers should pay for these costs. Ongoing costs of PX operation and utility load bidding functions shall not be so eligible and must be recovered from market revenues.

k. No § 376 treatment and no recovery shall be allowed which imposes costs on retail ratepayers associated with the utilities' wholesale contract responsibilities.

l. No recovery of costs shall be allowed under § 376 until it is determined that these costs will not be recovered through some other mechanism, e.g., Federal Energy Regulatory Commission-approved rates or directly from customers.

m. Restructuring implementation costs shall be recovered through a debit entry to the transition revenue account and shall not be assigned to separate cost categories such as transmission, distribution, etc.

This order is effective today.

Dated ________________________, at San Francisco, California.

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