Decision **ALTERNATE DECISION OF COMMISSIONER BILAS** (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 D 97-11-074.	Application 98-05-015 (Filed May 1, 1998)

(See Appendix A for list of appearances.)

INTERIM OPINION REGARDING PUBLIC UTILITIES CODE SECTION 376 AND SOUTHERN CALIFORNIA EDISON COMPANY'S RESTRUCTURING IMPLEMENTATION COSTS

Summary

In this decision, we consider the Phase 1 issues related to restructuring implementation costs for Southern California Edison Company (Edison) to which Public Utilities Code § 376[1] treatment applies. In Phase 1, we develop a set of principles or guidelines for considering program eligibility. 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. We also set forth cost causation and recovery principles for costs eligible for § 376 treatment.

We find that the costs of programs to accommodate implementation of direct access, the Independent System Operator (ISO), and the Power Exchange (PX) that are eligible for § 376 treatment are the reasonable and necessary costs incurred for such programs as of December 31, 1998. We recognize that certain costs may necessarily be incurred in 1999 to ensure that the new market structure is well established. Therefore, we will allow Edison to request recovery of 1999 programs for eligible categories on a case-by-case basis in a 1999 reasonableness review proceeding. Edison's request must be consistent with the guidelines we establish in this decision. We consider the costs incurred for start-up and development of the ISO and the PX reasonable, because these costs are established and approved by the Federal Energy Regulatory Commission (FERC). We also consider the costs incurred for the Consumer Education Program (CEP) and the Electric Education Trust (EET) to be reasonable, because

[1] All statutory references are to the Public Utilities Code, unless otherwise noted.

this funding has been pre-approved by prior Commission decisions. We direct Edison to file a new application to consider the reasonableness of all other eligible costs for 1997 and 1998. The principles set forth in this decision apply to Edison. The restructuring implementation costs incurred by Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) are the subject of separate proposed settlement agreements and are addressed in an accompanying decision.

Procedural History

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

[2] Decision (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.

accordance with the SB 960 rules, this proceeding has been categorized as ratesetting (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. On July 10, Commissioner Bilas issued a scoping memo which designated the assigned Administrative Law Judge (ALJ) as the principal hearing officer, 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 to conclude these proceedings no later than 18 months from the date of filing of the application, pursuant to SB 960, Section 13.

The 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), 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. Separate motions for adoption of settlement agreements for SDG&E and PG&E were filed on November 12 and November 13, respectively. At the parties' request, PG&E's and SDG&E's cases in chief were not the subject of the first round of evidentiary hearings.

Edison's Phase 1 issues were addressed in seven days of evidentiary hearings held from October 21 through November 3. Commissioner Bilas was in attendance for opening statements on October 21 and closing arguments on November 3. Phase 1 of Edison's application was submitted upon reply briefs, filed on December 15, 1998. Edison, ORA, CLECA/CMA, CIU, CAC/EPUC, TURN/UCAN, Enron, and Farm Bureau filed opening briefs. Edison, ORA, CLECA/CMA, CIU, Enron, and Farm Bureau filed reply briefs. The principal hearing officer completed and issued the proposed decision on time on March 11, 1999, 86 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 PX and 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.)

Edison's Request

In A.98-05-015, Edison seeks to establish the eligibility of particular cost categories for which § 376 treatment is appropriate and the applicable ratemaking and rate recovery mechanisms. Edison requests that the actual, reasonable costs incurred be afforded rate recovery and § 376 treatment. Because the costs of establishing this infrastructure were not included in frozen rates, Edison maintains that § 376 is an important part of the balance of risks and rewards established by Assembly Bill 1890 (Stats. 1996, Ch. 854).

Edison forecasts that approximately $430 million will be spent over the period 1997 to 2001 on restructuring implementation, as defined in § 376, but voluntarily agrees to limit § 376 treatment to $275 million of that total.[3] Of the $275 million, Edison contends that the Commission has already approved approximately $150 million for § 376 treatment. These costs have been approved for ISO development, PX, development, the consumer education program, and the electric education trust. Therefore, Edison seeks approval of an additional $125 million for § 376 treatment, assuming that all of these costs are incurred. Edison states that a significant portion of the $125 million has been spent on programs to accommodate direct access.

Edison maintains that implementation must necessarily occur throughout the transition period and plans to spend significant amounts in 1999, 2000, and 2001 to accommodate the implementation of the new market structures. Edison believes it is fundamentally unfair to limit implementation to those costs

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[3] When Edison refers to restructuring implementation costs, it refers to both capital expenditures and operations and maintenance (O&M) expenditures. The annual capital expenditures do not close to plant-in-service accounts until they have been completed and are operational. Therefore, the annual spending amounts must be converted into a revenue requirement by identifying the capital closed to plant, the annual amortization of such capital, and the gross-up of those amounts to reflect return and taxes. The amounts identified in this decision are costs rather than revenue requirements.

incurred in 1997 and 1998. Moreover, Edison contends that the dates related to implementation are contained in the statute itself, which references costs incurred before 2001. Edison reminds us that this debate is somewhat hypothetical if the utilities fully recover their generation-related transition costs before December 31, 2001, § 376 will never be triggered. Edison explains that it is not possible to demonstrate that recovery of restructuring implementation costs will reduce its opportunity to recovery generation-related transition costs until close to year-end 2001.

Edison claims that the following programs are instrumental to restructuring implementation, in addition to the start-up and development costs of the ISO, the start-up and development costs of the PX, and costs of the consumer education program and electric education trust:

- ISO/PX and other Wholesale Market Interface
  - ➜ PX Demand Forecast, Bidding and Settlement Program
  - ➜ Generation ISO/PX Systems Interface Program
  - ➜ Power Systems Controls and Management Program
- Direct Access
  - ➜ Customer Service Program
  - ➜ Energy Service Provider (ESP) Service Division Program
  - ➜ Implementation Support Program
- Hourly Interval Meter Installation and Reading Costs
  - ➜ Usage measurement Program
  - ➜ QF Payment Systems Change Program
- Utility Distribution Company (UDC) Billing Systems Modification Costs
  - ➜ Energy Cost Accounting Program
  - ➜ Retail Billing, Credit, and Collections Program

- Customer Information Release Systems

We will briefly summarize the purpose of each program, as Edison has presented it, and provide an overview of recorded and forecast costs for each program.[4] As directed in D.97-05-040, Edison established various subaccounts under the Industry Restructuring Memorandum Account (IRMA) to track these costs.

ISO Development and Start-up Costs

The costs associated with the ISO's start-up and development are recovered through the Grid Management Charge, which is a volumetric charge. The ISO's operating budget consists of two elements: the start-up and development costs to establish the ISO's basic infrastructure and operating systems, and its ongoing operating budget. FERC has approved a 1998 Grid Management Charge of $0.7831 per megawatt-hour. Edison now seeks § 376 treatment for the portion of the Grid Management Charge related to start-up and development costs, which total $65.7 million from 1998 - 2001.

PX Development and Start-up Costs

Edison's costs related to the start-up, development, and initial working capital costs of the PX result from the initial charge payments Edison makes pursuant to a FERC tariff of the PX. In a proposed settlement agreement pending before FERC, PG&E, Edison, and SDG&E would each pay a share of the initial charge payments in four installments, due on April 15, 1998, January 4, 1999, January 3, 2000, and January 2, 2001. According to this proposed

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[4] As stated in the ACR, Phase 1 does not discuss reasonableness issues associated with 1997 and 1998 costs, nor the forecasts of restructuring implementation costs. However, we provide such costs for information purposes.

agreement, Edison's share of each of the installments is $11.3 million, for a total of $45.4 million.

ISO/PX and Other Wholesale Market Interface Costs

In addition to providing funding for the start-up and development costs of the ISO and the PX, Edison is incurring costs associated with procuring energy, which involves PX demand forecasts, bidding, and settlement, generation ISO/PX systems interface, and modifications to Edison's power systems controls systems and voltage support installations. Edison spent $4.4 million in capital expenditures on these tasks in 1997 and projects spending $5.7 million in expenses and $39 million in capital expenditures over the 1998 - 2001 time frame, with the bulk of these costs attributed to the PX demand, bidding, and settlement area.

Edison has developed business processes and automated systems in order to purchase power from the PX on behalf of its bundled customers. In broad terms, these functions involve ordering the appropriate quantity of energy at the best prices in the PX market, which involves econometric and statistical knowledge, and reconciling the bid quantity and market clearing price of energy, which requires accounting and auditing skills. Edison asserts that costs incurred for these functions are specifically for the design, development, testing, and implementation of business practices and software programs related to the PX and also help to accommodate the implementation of direct access. Edison maintains that § 376 treatment is appropriate because the PX was created as a state-chartered institution to conduct a daily energy auction and because the Preferred Policy Decision required that the utilities must bid all their generation into the PX and purchase power on behalf of the utility's customers from the PX. In other words, Edison is required to use the Power Exchange as its scheduling coordinator. In addition, FERC tariffs and PX protocols impose several requirements related to the purchase of energy from the PX.

Edison's generation ISO/PX systems interface project includes costs for hardware and developing software that is capable of receiving cost and availability information from Edison's generating stations, submitting bids to the PX, receiving final schedules from the PX, tracking dispatch notices, analyzing settlement statements, and tracking disputes with the PX. Again, Edison asserts that these costs should receive § 376 treatment because state law mandates the PX and because Edison is required to bid all energy into and purchase all energy from the PX. Edison maintains that all associated costs with these programs are incremental costs.

Edison has also incurred costs to enable it to transact business with the ISO and the PX related to installation of temporary energy management system consoles at ISO facilities, ISO certification of Edison's meters at points of interconnection with other utilities, travel and meeting expenses for ISO and PX development, transmission owner communication with the ISO, ISO line losses, and ISO required meter data and ancillary services requirements. Edison maintains that such costs were necessarily incurred to modify its facilities in order to accommodate implementation of the ISO and PX and therefore should be eligible for § 376 treatment.

Consumer Education Program

In D 97-03-069, we concluded that expenditures incurred by the utilities for purposes of the statewide Consumer Education Program (CEP) "are recoverable from their customers pursuant to Section 376 because these costs are incurred to implement direct access." (D 97-03-069, mimeo. at p. 2.) We also determined that expenditures up to the total authorized funding level of $20 million, on a statewide basis, are reasonable, unless a party challenging those expenditures proves that they are unreasonable.

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. On July 30, 1998, the utilities filed a report on the results of this effort. On September 14, 1998, Assigned Commissioner Knight issued a ruling determining that no further proceedings were necessary since the aided awareness target of 60% was achieved. Edison now needs approval of a ratemaking mechanism to recover its costs associated with the CEP. Edison expects to spend $33.2 million in 1998 for this program.

Electric Education Trust

In D.97-03-069, we found that funding the initial level for the Electric Education Trust (EET) by approving § 376 recovery was appropriate. (D.97-03-069, mimeo. at p. 41, Conclusion of Law 22, p. 46.) In D.97-08-064, we increased the EET funding level to $13 million. The EET is scheduled to begin operating in 1999 and run through 2001. Edison will not actually fund the majority of EET costs until grants are awarded to various community based organizations for educational outreach activities. In D.97-07-098, we considered a work plan filed by the EET and ordered the EET to submit a revised schedule by September 30, 1998. Because of this timing, Edison expects that most of the significant costs required by EET will not be incurred until 1999 or 2000 and expects to spend approximately $7 million.

Direct Access

Edison has spent $5.5 million in expenses and invested $7.2 million in capital expenditures on programs associated with Direct Access in 1997. Edison anticipates spending approximately $106 million in expenses and $24 million in capital investments for the period 1998 - 2001.

The objective of the Customer Service program is to enable Edison to respond fully to customer inquiries and requests related to electric restructuring. This includes processing Direct Access Service Requests (DASRs) from ESPs, responding to customer requests and inquiries regarding direct access, and providing ongoing operational assistance to ESPs. Edison spent $1.5 million in expenses on these programs in 1997, and invested $1.1 million in capital expenditures. Edison forecast spending $76.8 million in expenses and $18.5 in capital expenditures for the period 1998 - 2001 for these programs. Edison states that all costs are incremental and were not contemplated nor included as part of the forecast for its 1995 general rate case (GRC). Edison has renovated facilities in Long Beach and hired and trained new employees to carry out these tasks, and expects to incur significant on-going costs during the transition period to support these efforts. The estimates for future costs are driven primarily by assumptions related to the number of DASRs to be processed, the volume of calls related to direct access, and the number of customers who choose direct access.

The ESP Services Division program includes tasks related to establishing and maintaining business relationships with ESPs. In contrast to the more routine tasks carried out by the ESP Support Center, the ESP Services Division proactively establishes and maintains a direct customer contact between Edison and individual ESPs. This relationship is focused on meeting the business needs of each ESP and the needs of "our mutual customers." (Exhibit 12, p.27.) Edison states that the implementation of direct access requires the utility to assume a leadership role in educating and training ESPs about critical business issues. Edison believes that such a program benefits all customers, including direct access customers, because it facilitates greater customer choice, enhanced consumer protection, and less end-use customer confusion. Edison spent $741,000 on this program in 1997 and forecasts spending an additional $5.7 million in 1998 - 2001, all claimed as incremental costs. Edison justifies these programs as part of its effort to ensure that customer choice is available to consumers as soon as practicable, consistent with § 330(n) and argues that such programs are consistent with D.97-05-040's directives to implement direct access.

The Implementation Support Program provides overall management, coordination, and support for all operational aspects of the direct access implementation program. These aspects include overall project management, budget and control support, auditing support, information technology infrastructure, employee training, and facilities development. Edison believes that overall project management is required to direct and synchronize the efforts of direct access implementation, to monitor and control its direct access spending, to focus on new processes and systems and review business effectiveness and compliance with regulatory mandates, and to support the necessary modifications and enhancements to existing information systems for direct access, including new interfaces among interrelated business activities. The Implementation Support program has also developed a training curriculum to instruct employees for new business practices related to direct access implementation. By year-end 1999, Edison anticipates that direct access training will cease to be a separate function. Finally, the facilities development aspect of this program involves the identification and build-out of facilities needed to house the incremental employees dedicated to direct access activities. Edison renovated a facility at Long Beach, which is now occupied by personnel performing direct access customer service and ESP support activities. Edison maintains that this approach has led to cost savings, for example, in installing new telephone call switches. Taken as a whole, Edison believes that the

Implementation Support program is necessary for and an important part of direct access implementation. Edison considers all costs incremental and has spent $3.2 million in expenses and $6 million in capital investments in 1997, and anticipates spending an additional $23.2 million in expenses and $5.5 in capital investments for the period 1998 - 2001.

Hourly Interval Meter Installation and Reading Costs

Edison explains that while this category of costs relates to implementation of direct access, these costs are incurred to accurately measure the hourly energy usage of direct access customers and to make this information available to other energy market participants for billing and settlement purposes. For direct access customers with hourly interval meters, costs are incurred for the purchase and installation of meters and for installation of systems to accurately collect, validate and edit that usage data in order to make it available to market participants. For direct access customers without such meters, costs are incurred to create hourly load profiles. Edison has also incurred costs for other metering services "necessary to implement direct access," including meter acquisition, testing, and verification of direct access customer usage data. In 1997, Edison incurred capital costs of $3.32 million and expenditures of $1.6 million. For the period 1998 - 2001, Edison anticipates spending additional capital costs of $35.2 million and expenses of $36.6 million. These costs also include costs to change existing computer systems used to compute QF payments based on hourly pricing periods rather than time of use pricing formulas.

Edison contends that all such costs are "<u>necessary for and a part of</u>" the implementation of direct access. (Exhibit 27, p. 22, emphasis in original.) D 97-05-039 provided that ESPS which wish to offer their own metering services must enter into a service agreement with the distribution company that specifies the nature of the information to be collected, how data will be shared, and how to ensure that metering equipment is installed, maintained, and calibrated properly, and required that "[t]he distribution utility shall not unreasonably refuse to enter into such agreements." (D.97-05-039, Ordering Paragraph 3.) Edison also claims that because § 390 changed the QF contracts payment structure from formulas representing Edison's avoided costs to basing energy payments on the market clearing price, costs incurred to implement such changes are required by statute and therefore must receive § 376 treatment.

UDC Billing Systems Modification Costs

Edison has developed particular energy cost accounting and retail billing systems to address interaction with the PX and the ISO. Apart from the must-run generating units, hourly energy prices in the PX are determined by the marginal generator, that is, all generators receive (and buyers pay) the same hourly energy price, which is determined by the cost incurred by the last unit that goes on-line in a particular hour. This is the unadjusted energy charge. Edison states that this charge cannot be directly translated to customers' bills, because adjustments must be made to account for distribution line losses, PX administrative charges, ancillary services, and differing load profiles for those customers who are not metered. Edison maintains that its new energy cost accounting system provides important information not only to its own billing system, but to ESPs which rely on Edison for billing and forecasting information. Edison spent $196,000 on expenses related to these programs in 1997 and expects to spend an additional $956,000 during 1998 - 2001. Edison maintains that these programs are necessary in order to properly calculate energy prices and the residual amount of CTC relating to direct access customers.

Edison has also developed programs related to retail billing, credit, and collections to present the bills and separately stated billing components to direct access customers and to ESPs. These bills are either available as UDC consolidated, where the customer receives one bill from the UDC with all charges, including those provided by the ESP, ESP consolidated, where the customer receives one bill from the ESP, including those provided by the UDC, and dual billing, where the customer receives separate monthly bills from both the UDC and the ESP. Retail billing costs are particularly sensitive to the DASR completion rate, due to the labor-intensive nature of various tasks. For 1997, Edison expended $6.7 million, $3 million of which were capital costs and $3.7 million of which were expensed. For the period, 1998 - 2001, based on processing 12,000 DASRs per month, Edison expects to incur an additional $11.8 million in capital costs and $57.2 million in expenses. (Exhibit 6, updated workpapers, p. 64.) Because § 392(c) requires that each UDC disclose the total charges associated with transmission, distribution, generation, and the CTC, Edison asserts that the costs incurred for its billing system modifications should receive § 376 treatment, which is also consistent with the directives of D.97-05-039.

Customer Information Release Systems

This program consists of components for handling the release of confidential and non-confidential customer information. The objective of this program is to make customer information available to all market participants. Edison claims that access by other market participants to confidential (i.e., with the customer's name) and non-confidential (without the customer's name) customer-specific usage information accommodates direct access implementation. Edison incurred $1,300 in expenses for this program in 1997 and expects to incur approximately $4 million in expenses and $3 million in capital expenditures for the period 1998 through 2001. Edison believes this program is fundamental to accommodating implementation of direct access and is consistent with the directives of D 98-03-072.

Edison's Internal Policy Guidelines

In addition to the criteria established by § 376 and our decisions, Edison developed policies to guide its business units in determining whether programs would qualify under § 376. These policies are: the project must be necessary to implement restructuring; the activity and its costs must be incremental to existing authorizations; and employees, contractors, and capital projects must be exclusively related to implementing restructuring for their costs to be recorded in a § 376 account. Edison contends that requiring that a project be necessary to implement restructuring is stricter than the "accommodate" standard of § 376. The term "incremental" means that the costs of programs were not already reflected in rates adopted as of June 10, 1996. Edison maintains that requiring that costs related to employees, contractors, and capital projects be exclusively related to implementing restructuring is also a higher standard than that required by § 376. According to this standard, if any portion of the work of new employees is not related to implementing restructuring, then none of that employee's labor costs are allocated to the IRMA subaccounts. Existing employees must be dedicated exclusively to the "development, implementation, maintenance, and operation of direct access, the ISO, or the PX" in order to have these labor costs allocated to the IRMA subaccounts.

Voluntary Cap

On July 1, 1998, Edison sent a letter to Senator Peace offering to voluntarily limit to $275 million the amount of utility generation-related transition costs it will seek to recover after the end of 2001. In that letter, Edison also agreed to share the risk of recovery associated with any prospective Commission decisions associated with the implementation of direct access, the ISO, or the PX by limiting its request for § 376 treatment of these future costs to a fraction of the costs incurred. This amount includes Edison's share of the start-up costs of the ISO and PX (approximately $65 million and $45 million, respectively) and the costs of consumer education programs (approximately $40 million). The $275 million also includes costs associated with providing direct access and revenue cycle services unbundling. Edison is not asking for our approval of this cap and states that because it is voluntary, we have no authority to order Edison to accept a lower cap. Edison also contends that even if we had such authority, the record in this proceeding does not contain the substantial evidence necessary to limit the amount of costs subject to § 376 treatment.

Ratemaking

Because a rate freeze is imposed, Edison recovers its transition costs through a residually determined CTC. In other words, revenues are allocated from the total frozen rate levels to individual rate components, with the remaining balances identified as the CTC revenues. Edison proposes establishing a new memorandum account to track revenue requirements associated with approved costs eligible for § 376 treatment and to allocate a portion of total billed retail revenues to the recovery of these costs. Thus, approved and eligible restructuring implementation costs would be recovered through available headroom. This methodology would reduce the amount of headroom available to recover transition costs and therefore could displace recovery of such costs. In that case, those displaced transition costs would be eligible for recovery after the rate freeze period. In the event that we approve costs as eligible for recovery, but not eligible for § 376 treatment, Edison proposes that these costs also be recovered in the TRA, but not tracked in the memorandum account for later recovery as displaced transition costs. Amounts in the Section 376 Tracking Account would then be compared to the applicable portions of the TCBA to determine if any generation-related plant and regulatory asset transition costs in the TCBA can be recovered beyond 2001.

ORA's Position

ORA asserts that implementation of the ISO, PX, and direct access was accomplished by year-end 1998. ORA maintains that § 376 treatment should be given only to those programs that are absolutely necessary to allow the ISO, PX, and direct access to begin operations. ORA recognizes that additional costs must be incurred to improve and refine the already-implemented ISO, PX, and direct access programs, but recommends that these costs should not be treated as § 376 costs.

Contrary to TURN and Farm Bureau, ORA maintains that post-1998 restructuring-related costs that are not afforded § 376 treatment may be recovered in distribution rates. In fact, ORA believes that PBR Z-factor criteria should be applied to these costs. Thus, under this proposal, Edison would recover reasonably incurred labor expenses for electric restructuring and would also apply Z factors to post-1998 electric restructuring expenditures for later recovery in rates.

ORA explains that costs that are imposed on the utilities by law are externally managed costs and should be eligible as § 376 costs. Costs that are within the utility's internal control are internally managed costs and might assist the utility in competing in the new regime; therefore, ORA recommends that these costs receive greater scrutiny.

ORA contends that generation-related costs should be ineligible for § 376 treatment. ORA recommends that costs of generation bidding, settlement, and billing systems, and revenue quality meters are either administrative and general costs or operation and maintenance costs, and thus, should be recovered as "going forward" costs. In other words, such costs should be recorded in existing must-run and non-must-run memorandum accounts and recovered from market revenues attributed to the PX component, not from ratepayers. Similarly, ORA argues that costs of ESP services are not services to customers and should not be recoverable from customers.

ORA recommends that the costs of a generalized unbundling of billing and new standard bill formats should be ineligible for § 376 treatment, despite the fact that unbundling or cost separation is required by § 368(b). ORA does not believe that such unbundling facilitates customer choice or accommodates implementation of direct access. ORA would exclude 50% of the expenditures under revenue reporting in the UDC Billing Systems Modification subaccount.

ORA agrees with all parties that restructuring implementation costs receiving § 376 treatment must be incremental to costs included in base rates and argues that Edison has the burden of proof to show that costs are truly incremental and do not include costs savings or avoided cots associated with functions no longer performed. ORA supports TURN's proposal that a reduced rate of return be applied to accelerated recovery of § 376-eligible assets.

TURN's Position

TURN and UCAN recommend 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 performance-based ratemaking (PBR) mechanism, forecasts will be overestimated. In addition, including capital costs in rate base will artificially inflate the distribution rate base. TURN and UCAN recommend that all capital-related § 376 costs should be amortized over the remainder of the transition period, should earn the reduced transition cost rate of return, and should be kept separate and apart from the distribution PBR mechanism.

All parties agree that in order for costs to be eligible for recovery under § 376, the recovered implementation costs must delay the recovery of transition costs beyond the end of the transition period. TURN/UCAN recommend that the following additional principles be adopted:

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.

Farm Bureau's Position

Like TURN, Farm Bureau is concerned that proposals to arbitrarily cut-off implementation as of year-end 1998 would result in inappropriately shifting cost responsibility to bundled service customers. Because restructuring benefits all customers, the Farm Bureau recommends that the utilities recover their reasonably incurred eligible restructuring implementation costs from all customers according to allocations in place as of June 10, 1996.

Farm Bureau is particularly concerned that we do not establish an arbitrary eligibility cut-off date for implementation, because Edison indicates that it may seek recovery of 1999 - 2001 restructuring implementation costs in its PBR mechanism. If this were to occur, customers that are not subject to Edison's distribution PBR mechanism could escape payment of such costs. In addition, if costs are added to the PBR on a forecast basis, it might provide Edison with unwarranted benefits. To the extent that Edison can provide services at lower costs than its benchmark, Edison is allowed to keep the difference as profit. Thus, if the forecasts of costs recovered under PBR are high, lower actual costs accrue to Edison as profits, are not applied to transition cost recovery, and could provide Edison with PBR performance bonuses. In addition, costs added to PBR rates are not subject to reasonableness reviews and would automatically be escalated each year (according to the inflation formula established for the PBR mechanism) and could thus decrease the headroom available for transition cost recovery.

Farm Bureau also recommends that a determination of broad eligibility in Phase 1 should not restrict future discussions of this eligibility in annual reasonableness reviews, because eligibility of various programs for § 376 treatment may change as the market changes. Farm Bureau also recommends that Phase 2 compare the § 376 guidelines and mechanisms for recovery adopted for PG&E and SDG&E with those adopted for Edison, since some of those proposals may provide more reasonable resolutions of common issues than Edison has presented.

Farm Bureau is opposed to Edison's cap of $275 million on post-rate freeze transition cost recovery, which it represents as a "soft" cap. A soft cap means that Edison could seek to have additional, unexpected restructuring costs increase this cap. Farm Bureau prefers a much lower cap, under which any additional costs would be paid for by Edison's shareholders.

CLECA and CMA's Position

CLECA and CMA recommend that costs eligible for § 376 treatment must meet four criteria: the costs must be reasonable, funded by the utilities, limited to those necessary to accommodate implementation of the ISO, PX, and direct access, and not reimbursed by the ISO or PX. CLECA and CMA agree that implementation has occurred as of December 31, 1998. While these programs may operate in the future, ongoing O&M costs cannot be considered implementation costs. Furthermore, while CLECA and CMA recognize that new features will be added to the ISO and PX in the future, these are enhancements rather than implementation costs. CLECA/CMA argue that eligible costs must be limited to those contemplated at the time the legislation was enacted; therefore, revenue cycle services unbundling costs would not be eligible. All eligible costs must be incremental in nature, with any savings or avoided costs recognized as offsets.

CLECA and CMA propose the following guidelines:

1. Section 376 must be implemented in a manner that preserves the balance of risks and benefits from the regulatory and legislative bargain.

2. Only costs incurred to establish the ISO, PX, and direct access are recoverable as § 376 costs. The costs of operating these programs on an ongoing basis re not eligible under § 376.

3. Costs incurred after 1997 are not eligible for § 376 treatment.

4. All generation-related costs should be recovered either through spin off or sale of utility generation facilities or as "going forward" costs.

5. To be recoverable under § 376, all ISO, PX, and direct access implementation costs must have been funded by the utilities and must be subject to a reasonableness determination.

6. Revenue cycle service unbundling costs are not eligible for § 376 recovery. RCS services include meter reading, meter services, meter data management, meter ownership, and billing.

7. Costs eligible for § 376 recovery must be incremental to those costs that relate to ongoing utility business. Savings associated with net staff reductions, more efficient systems, or discontinued activities should be offset against § 376 costs. Edison should be directed to identify all avoided costs arising from restructuring and to present that study in Phase 2. Edison should also be directed to exclude labor costs from § 376 attributable to Edison employees whose former positions were not filled within three months.

8. Costs eligible for § 376 recovery must not extend recovery of competitive transition costs beyond the end of the transition period.

9. There can be no recovery of costs under § 376 until it is determined that they will not be recovered through FERC-approved rates or directly from customers through fees.

10. No § 376 recovery or retail recovery should be allowed which imposes costs associated with wholesale contract responsibilities on retail ratepayers.

CIU's Position

CIU asserts that implementation of the ISO, the PX, and direct access ended on March 31, 1998, and that any costs incurred thereafter are not eligible for § 376 treatment. CIU believes that because the statute provides no guidance as to when implementation ends, we have the discretion to make this determination. In addition, CIU contends that eligible cost categories must be limited to only those costs to accommodate implementation of direct access, the ISO, and the PX, not restructuring costs in general. Because the ISO and PX are operating and because consumers are choosing to procure electricity from various providers, CIU asserts that implementation is complete, while acknowledging that refinements and enhancements may and should occur.

CIU recognizes that we have already approved several cost categories as being eligible for § 376 treatment, but sees no reason that such actions should continue. For example, while costs related to the Universal Node Identifier System were approved for § 376 treatment in D 98-11-044, CIU asserts that direct access is already implemented and while such a service may be helpful, it is not required.

CIU recommends that the concept of "competitive neutrality" requires that several costs be eliminated from eligibility for § 376 treatment. In D 97-11-074, we determined that it is vital to ensure that no greater competitive advantage is afforded incumbent utilities than any other competitor in the new market and that we foster competition in the nascent marketplace. Thus, CIU asserts that costs expended on implementation activities that would allow Edison a competitive advantage in the new market should not be allowed recovery from other than market revenues. CIU points out that all market participants doing business with the ISO and the PX were required to develop processes to do business with those new institutions. CIU maintains that allowing Edison to recover these costs in rates in a way that could extend transition cost recovery confers a competitive advantage on Edison. In addition, CIU asserts that all competitors must incur costs related to development or modification of customer billing systems, processing DASRs and customer service functions.

CAC and EPUC's Position

CAC and EPUC agree ongoing costs, i.e., costs to refine and enhance direct access, the ISO, or PX, cannot be given § 376 treatment. CAC/EPUC assert that implementation of these programs has occurred as of December 31, 1998. CAC/EPUC propose an eligibility test that would limit implementation costs to those costs necessary to give initial practical effect to direct access, the PX, or the ISO. In other words, these programs could not have become operational without that cost being incurred. Therefore, if significant costs are allowed eligibility for § 376 treatment, this would effectively permit the utility greater headroom during the transition period and in effect guarantee recovery of transition costs and delay full competition.

CAC/EPUC define ongoing costs as costs incurred after direct access, the PX, and the ISO are operational. CAC/EPUC contend these costs are incurred to allow Edison to participate in the market and could be recovered through fees, rates set after the rate freeze, PBR, or other proceeding, or simply through the market. CAC/EPUC maintain that certain ongoing costs are included in

Edison's current rate level; e.g., meter data management, supervisors' salaries, computer information systems, credit checks, power purchases,, processing of customer service requests, and customer billing. CAC/EPUC recommends that Edison be required to eliminate these costs from its request for actual cost approval.

CAC/EPUC contend that market participation costs are not implementation costs. All entities competing in the market will incur costs to modify its operations so that it can interface with the ISO and PX and offer direct access. These parties agree with CIU that Edison's cost of demand forecasting, bidding, and settlement, which allow it to participate in the PX, are internal costs not incurred to accommodate implementation of direct access, the PX, and the ISO. CAC/EPUC list other market participation costs as purchases of energy from the PX, preparation of customer bills, processing of forecasting, settlement, and load research information, developing systems to schedule and dispatch generating units, and creating a direct access ESP support center. CAC/EPUC argue that if Edison is allowed to charge these costs to all customers, direct access customers will have to pay for the same costs twice.

CAC/EPUC challenge Edison's contention that all costs are incremental with no associated cost savings and recommends that Edison be required to undertake a comprehensive study to identify avoided cost savings before it is allowed to extend the transition period by any amount of costs receiving § 376 treatment.

Enron's Position

Enron believes functionalization, or cost assignment to particular services or function, is necessary to facilitate continued restructuring efforts, assist the transition to competitive markets, prevent subsidization of utility-offered competitive and potentially competitive services by captive ratepayers, and ensure alternate service providers have the ability to compete with the utilities in the provision of competitive services.

Enron contends that Edison must functionalize its restructuring implementation costs by the following cost recovery categories for the purposes of recovery: distribution (non-revenue cycle services), distribution (revenue cycle services), distribution (oversight), transmission, procurement, and generation. Once restructuring implementation costs are properly functionalized, recovery becomes apparent; e.g., transmission costs are recovered through FERC-jurisdictional rates, generation costs are recovered from wholesale generation market rates.

Enron states that Edison's costs of participating in the generation market are recovered from revenues received in that market. Enron proposes that costs expended on generation bidding, scheduling, and settlement are wholesale generation costs and should not receive § 376 treatment.

Enron recognizes that Edison procures energy on the retail level and receives payments from both bundled and direct access customers. The costs of procurement which are assessed to Edison from an outside source are reflected in the PX credit that direct access customers receive from Edison, and include PX energy costs, ancillary services costs, ISO grid management charges and the PX administrative charge. However, Enron explains that the PX credit does not reflect cost incurred directly by the UDC and Edison proposes to recover these internal costs from all distribution customers. Enron contends that these internal costs (encapsulated within its PX demand forecast, bidding, and settlement program, along with certain procurement costs currently embedded in rates[5]) are comparable to the costs incurred by ESPs to provide direct access service.

Thus, Enron believes that allowing recovery of these procurement costs in distribution rates allows Edison to subsidize the retail price of procurement through monopoly distribution rates. In addition, allowing recovery of such costs from all customer results in direct access customers paying the costs of these type of procurement activities twice: once to the ESP from which it receives the procurement services and again to the UDC, in the form of distribution rates. Thus, Enron contends that these costs should be functionalized as procurement costs, recovered from bundled customers pursuant to Edison's Schedule PX, and reflected in the PX credit.

Edison's unbundled transmission services are now under the jurisdiction of FERC and Enron recommends that Edison seek recovery of costs associated with its role as transmission owner at FERC.

Enron asserts that Edison has acquired new roles pertaining to the facilitation of competition and customer choice. These new oversight roles should be functionalized as distribution - oversight and recovered from all customers. Enron also contends that such an oversight role is associated with the transition of RCS as part of the bundled utility services to a competitive service. The utilities, for example, provide oversight for meter data management agents (MDMA) and meter service providers. In addition, each utility is also an MDMA and a meter service provider. Enron believes that the level of projected incremental revenue cycle services costs is too high (approximately 30% of total

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[5] In A.98-07-006 et al., Enron has proposed to include certain UDC procurement costs currently embedded in rates in the PX credit.

costs) and that we must ensure that Edison does not recover the costs of competitively positioning itself in the RCS market from ratepayers. All ESPs and meter service providers must bear similar costs and must be compensated from their direct access customers. Enron recommends that we require Edison to separately identify and track all new costs expended in relation to RCS in order to allow RCS credits to be properly calculated and the RCS market to develop.

Discussion

We will discuss the policies guiding our consideration of the principles established for considering costs for § 376 treatment. We will then discuss eligibility of particular programs and costs in light of these principles. Next, we consider cost recovery and ratemaking issues. Finally, we will delineate our adopted guidelines for § 376 treatment and outline the next steps to be taken in reviewing costs for reasonableness.

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. Edison believes the tasks of "accommodating implementation of direct access, the ISO, and the PX" will not end until the end of the transition period, 2001, and the associated costs of developing a completely refined and sophisticated market are all implementation of direct access, the ISO, and the PX. Therefore, Edison contends that all costs should be eligible for recovery <u>and</u> all costs should receive § 376 treatment. All ratepayers should bear these costs, which should be recovered as actually incurred and reviewed for reasonableness. ORA and the large users believe that the tasks of accommodating implementation of direct access, the

ISO, and the PX ended as of December 31, 1998, at the latest. Thus, only the costs of developing the market to that point should receive § 376 treatment. However, certain costs of refinement and enhancement may be recovered as forecast costs in distribution PBRs or GRC. Generation costs and costs that must be incurred by other competitors should be recovered from market revenues. TURN/UCAN and Farm Bureau believe restructuring implementation costs should be declared eligible for § 376 recovery or not recovered in monopoly rates at all. Enron does not discuss cut-off dates for implementation, but agrees with TURN/UCAN that § 376 treatment and recovery should be allowed only for costs incurred and deemed reasonable and necessary for implementation.

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. The statute 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 Power Exchange, the Independent System Operator, 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.
>
> 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 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.) While the record shows that systems may still be evolving, Edison agrees that the ISO is managing the power grid that is under its control, consumers have choice in purchasing electricity through direct access, and the PX is awarding bids and developing invoices. (RT pp. 135-136.) These actions have been occurring since March 31, 1998.

CIU has a valid point in recommending that only those necessary and reasonable costs incurred as of March 31, 1998 to accommodate the implementation of direct access, the ISO, and the PX receive § 376 funding. We agree with ORA that allowing implementation of such programs as of year-end 1998 is generous, but allows for necessary post-operation experience and modifications. In addition, there may be certain eligible categories that require funding in 1999 to ensure that the ISO, PX, and direct access are implemented. We will allow Edison to request § 376 treatment and associated cost recovery on a case-by-case basis. Edison may request such treatment in a new application for reasonableness review of 1999 costs. Consistent with the guidelines that we discuss below, approved costs will be recovered as restructuring implementation costs only.

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

We do not agree that costs incurred by Edison but not spent on approved implementation activities, as defined in this decision, should be recoverable from ratepayers in any other form. We will carefully evaluate costs to determine if

Edison incurred the 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) operate as a competitor in the new market structure.

If a utility distribution company (UDC) is operating under a PBR mechanism, ongoing costs are already contemplated in the operation of the distribution PBR mechanism, as Farm Bureau asserts. These costs must not additionally be recovered from ratepayers in the form of implementation costs. 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. We agree with CIU that various costs are already embedded in rates, for example, costs related to meter data management, salaries paid to supervisors, and customer billing costs. In addition, by adopting PBR regulation, we explicitly expect productivity to 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. In this way, we address both TURN's and Farm Bureau's concerns. While we may be excluding various costs from § 376 treatment, they cannot be re-categorized 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. We will carefully evaluate costs 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 costs are simply a cost of operating in the 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 eligible costs that receive § 376 treatment must be incremental to those costs covered in current rates. As discussed above, these costs must also be incremental to those costs that relate to ongoing utility business. Edison's cost of doing business has been approved in its distribution PBR. If new activities are staffed by personnel who have been moved from functions that are now obsolete or are discontinued, these costs continue to be included in the PBR mechanism. Elimination of these functions will contribute to cost efficiencies and increased productivity under the PBR mechanism, as Edison acknowledges (Exhibit 2, p. 27). These costs are not incremental and shall not receive § 376 treatment. While Edison claims that this action would be equivalent to funding the direct access employee with productivity savings achieved under the PBR, the fact is that funding for a certain level of employees (based on historical trends and averages) has been implicitly assumed in the starting point for the PBR. We will not allow what amounts to double recovery by granting § 376 treatment for costs that are not incremental. Similarly, Edison should not seek to recover employee transition costs for personnel who staff new activities and who would otherwise have worked on discontinued functions.

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

Certain features of implementation may reduce costs for Edison. It is reasonable to incorporate these avoided costs and any associated cost savings into a final determination of costs receiving § 376 treatment. We direct Edison to identify and quantify all avoided costs associated with restructuring implementation costs, so that costs savings can be considered in approving the reasonableness of costs eligible for § 376 treatment. Edison has the burden of proving that its costs are incremental and that all avoided costs have been quantified appropriately. Edison shall provide the methodology, workpapers, and results of this study to all parties prior to the reasonableness review of these costs.

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

It is axiomatic that 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.[6]

Eligibility of cost categories

We will address each category of costs that is eligible for § 376 treatment and explain our reasoning in making these determinations.

[6] We will not address the issue of fees for DASR processing or fees for discretionary services. Pursuant to an ACR 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.

ISO and PX start-up and development costs have been funded and are eligible for § 376 treatment

Edison's share of both the ISO and PX start-up and development costs are eligible for § 376 treatment. No capital expenditures have been incurred for these tasks (Exhibit 11, p. 4). Edison's share of the PX start-up and development costs are assessed in the Initial Charge, to be payable in four annual installments, anticipated to equal approximately $11.4 million in 1998, 1999, 2000, and 2001. Edison's total share of these costs is $45.4 million. 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.)

The costs associated with the ISO's start-up and development are assessed through the Grid Management Charge, a volumetric charge. Edison's share of the start-up and development costs, included in the 1998 Grid Management Charge of $0.7831 per megawatt hour, equals $17.4 million in 1998 and $16.1 million in 1999, 2000, and 2001. Edison's total share of ISO start-up and development costs is $65.7 million. Costs associated with the ISO and PX start-up and development must be incurred by year-end 1998, but payments made by Edison 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.

CEP costs are eligible for § 376 treatment

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. In 1998, Edison forecast revenue requirements of $33.2 million for the CEP program. The consumer education program is required by statute (see

§ 392(b))[7] 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; no other market participant is required to expend these costs.

EET costs are eligible for § 376 treatment

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 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. $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.

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[7] 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.

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. Edison anticipates spending $7 million related to EET in 1998. Edison anticipates spending only an additional $113,000 in 1999. The total amount that can be spent on this effort in 1999 - 2001 cannot exceed $7.1 million.

Market interface costs are a cost of operating in the new market and are not eligible for § 376 treatment.

All costs recorded in the ISO/PX and Other Wholesale Market Interface Costs subaccount of the IRMA are in addition to funding the start-up and development of the ISO and the PX. As described above, these costs are incurred to procure energy, which involves PX demand forecasts, bidding, settlement, generation systems interface and modifications to Edison's power systems controls systems and voltage support installations. We agree with TURN that we must distinguish the set-up costs of the PX from the ongoing costs. Certain incremental design, development, and testing costs related to market interface should also be eligible for § 376 treatment for 1997 and 1998, to the extent these costs were required to implement the PX and ISO. We agree that, initially, UDC bidding of default customer load into the PX is a necessary part of implementation of the PX and the new market structure and § 376 treatment should be provided for 1997 and 1998 costs. After 1998, however, bidding default customer load costs should not receive § 376 treatment but must be recovered from bundled customers as part of the PX energy charge.

The ongoing costs of PX operation and provision of PX aggregation services should be charged only to PX users. Generation costs associated with the PX, such as re-metering of existing power plants and development of computer programs for those plants to bid into the PX are not eligible under § 376, but must be recovered from operating in the market. This includes settlement costs, which, again, are costs that must be incurred by all market participants.

Costs associated with wholesale contract responsibilities are not eligible for § 376 treatment.

Edison does not seek recovery of costs associated with its wholesale contract responsibilities. Edison concurs with ORA, TURN/UCAN, and CLECA/CMA that such costs should not be recovered from retail ratepayers. We concur. Costs related to these contracts have been excluded from CPUC-jurisdictional rates and have not been found to be recoverable from retail customers. This proceeding does not provide the opportunity to transfer costs from wholesale customers to retail customers. No recovery should be allowed which imposes costs on retail ratepayers associated with the utilities' wholesale contract responsibilities.

Direct access costs are eligible for § 376 treatment only to the extent these costs are required to implement this program and only through December 31, 1998.

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 stated:

> To ensure that direct access is available, accessible, and convenient, our preference is to open up direct access as widely and as quickly as possible, limited only by binding technical constraints. As discussed below, based on parties' comments in this proceeding, there are no binding operational or technical

constraints which stand in the way of opening up direct access to all customers on January 1, 1998.

* * *

A direct access program designed along these lines would limit the ability of the investor-owned electrical corporations to influence prices in the PX. In addition, such a direct access option offers a viable, effective, and dependable alternative to the PX for both consumers and suppliers of electric energy products and services. As discussed in the sections which follow and in our decision on the customer education program, we therefore adopt the following:

- The opportunity for all customer classes to choose direct access as an option immediately;
- Provision of customer identification and marketing information on an equal basis to potential electric service providers;
- Removal of barriers to potential new entrants who wish to establish customer relationships for a variety of energy-related products and services; and
- Establishment of adequate consumer education, information, and protection programs. (D.97-05-040, mimeo. at p. 15.)

* * *

AB 1890 shortens the time by which all customers shall have the option of direct access available to them. Under AB 1890, any such phase-in must be completed by January 1, 2002. In addition, it provides that any phase-in of customer eligibility for direct transactions shall be equitable to all customer classes and <u>accomplished as soon as practicable, consistent with operational and other technological considerations</u>. (Section 365(b)(1), emphasis added.) (*Id*. pp. 18-19.)

PG&E, Edison, and SDG&E agreed that no technical constraints existed to allowing direct access for all customers as of January 1, 1998. No technology-based limitations were identified which would impede or harm the reliable operation of the electrical system. We also determined that there were no other operational considerations, affecting the physical reliability and operation of the system that warranted a phase-in period. 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.[8]

Edison has established its direct access implementation program and requested § 376 recovery as if a phase-in approach were required. This is not correct. 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 indicated such activities would include 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.

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

We determined that these cost categories were too broad to distinguish which specifically could be attributed to implementation of direct access, but 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. We agree with ORA that these costs should receive greater scrutiny because they are under the utility's control. We will discuss the eligibility of the various program costs included in each of these subaccounts.

Only certain costs recorded in the Direct Access Implementation subaccount will receive § 376 treatment in 1997 and 1998, to the extent these costs are found reasonable.

The 1997 and 1998 costs of DASR processing included in the Direct Access Implementation subaccount are eligible for § 376 treatment, to the extent these costs are determined to be reasonable in Phase 2. DASR processing is a critical task in allowing implementation of direct access to begin. Similarly, the 1997 and 1998 reasonable costs of responding to customer requests and inquiries regarding direct access are eligible for § 376 treatment. However, the costs of responding to and processing requests for interval meters and related metering services should not receive § 376 treatment. These are simply costs of operating in the new world and should be recovered from market revenues. Nor should handling customer complaints about ESPs, direct access, and restructuring receive § 376 treatment. Again, these are simply costs of operating in the new competitive market, as are customer requests to return from direct access to bundled utility service.

ESP Support, which includes implementing and maintaining the ESP agreements between Edison and various ESPs, are costs of operating in the marketplace, costs which are being incurred by each and every market competitor. However, we agree that for 1997 and 1998, these are critical services to ensure that the nascent competitive market is viable. Reasonable costs associated with these services should receive § 376 treatment. However, costs incurred for ESP Provider Services are not required to implement direct access nor to foster the competitive marketplace. These costs must be recovered from market revenues. Finally, costs incurred for implementation support services in 1997 and 1998 will receive § 376 treatment for overall project management, information technology infrastructure, and employee training. Costs incurred for direct access budgeting and control, auditing, and facilities development are not costs incurred to ensure implementation of direct access.

Load profiling costs are eligible for § 376 treatment; otherwise costs incurred under the Hourly Interval Meter Installation and Reading Costs subaccount are not eligible.

In general, we do not agree that costs incurred under the Hourly Interval Meter Installation and Reading Costs subaccount are necessary for and a part of the implementation of direct access. This program is designed to allow Edison to accurately measure the hourly energy usage of direct access customers and to make this information available to other energy market participants for billing and settlement purposes. These costs must and will be incurred by all market participants. In D 97-05-039, we stated that energy suppliers should be allowed to provide and customers should be allowed to choose the billing and metering systems that are best for their purposes, so long as the metering systems are consistent with various standards. These are revenue cycle services and result in additional retail competition. Thus, these are competitive services and the costs of providing such services must be recovered from the market. These services are not required to implement direct access and will not receive § 376 treatment. However, costs related the creation of hourly load profiles that are used to estimate hourly consumption are eligible for § 376 treatment. This task is necessary to accommodate the implementation of direct access. Eligible costs are those related to creating load profiles that are based on existing rate categories, systems, procedures, load research meters, and samples and, therefore, should require minimal incremental costs to make customer class-based profiles available on January 1, 1998.

Costs incurred under the UDC Billing Systems Modifications Costs subaccount are not eligible for § 376 treatment.

Edison has developed particular energy cost accounting and retail billing systems to address interaction with the PX and the ISO. The energy cost accounting system provides information to Edison's billing system and to ESPs that rely on Edison for basic billing and forecasting information. Edison states that the ultimate goal of this program is to provide its billing system with information sufficient to render accurate and timely bills to Edison's customers and to make accurate and timely information available to ESPs. The energy cost accounting system calculates the PX energy charge along with adjustments such as unaccounted for energy costs, ancillary services, PX administrative costs, and imbalances, along with distribution line losses. These adjustments are also required in order to give direct access customers the correct credits. We will allow not § 376 treatment for costs incurred for these tasks in 1997 and 1998. Such accounting costs are required of energy service providers to ensure that timely and accurate billing can take place.

In general, all market participants must implement billing systems. Therefore, the costs incurred for billing modifications should be recovered from market revenues. However, because §§ 368(b) and 392 require that the utilities identify and disclose individual rate components, we will allow § 376 treatment for costs related to such disclosure. This function is required by statute and is required in order to compute the PX charge and the associated CTC. This task is necessary to accommodate implementation of the new market structure.

The costs of the modified billing system ordered in D.97-05-039 are part of the costs of operating in the new market and should be recovered from market revenues. As we determined in D.98-09-070, "we found that competition in metering and billing is not a goal in itself but a means to achieve effective competition in generation markets." (D.98-09-070, mimeo. at p. 2.) We allowed the UDCs to recover the incremental costs of unbundling revenue cycle services in service charges to ESPs. We stated specifically that we did not intend to allocate these to the general body of ratepayers as a matter of fairness, consistent with sound pricing principles. (*Id.*, mimeo. at p. 16.)

Only certain costs incurred under the Customer Information Release Systems Costs subaccount are eligible for § 376 treatment.

Only the reasonable costs of activities that the UDCs perform with respect to the opt-out list may be included for § 376 treatment, as provided for in D.98-03-072, because the opt-out list is a statutory requirement. The costs of providing other customer-specific information must be recovered from the market.

Costs recorded in the Direct Access Discretionary Services Costs Memorandum Account are not eligible for § 376 treatment.

Direct access services that are discretionary and recorded in the Direct Access Discretionary Services Costs Memorandum Account are clearly not required for implementation and shall not receive § 376 treatment.

We have previously determined that UNIS costs are eligible for § 376 treatment.

In D.98-11-044, we addressed a universal node identifier system (UNIS) and authorized PG&E, Edison, and SDG&E to track costs related to assigning labels or numbers to every service delivery point (SDP), or end point, on the utility's electric distribution system. 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. However, because of parties' opposition to the workshop report, it was not filed until late in March 1998. An alternative was not presented to the Commission until late August. As a result, the Commission decision wasn't issued until November, when it was obviously too late to implement this program. 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 exception to our general principles.

Summary of cost categories eligible for § 376 treatment

To summarize, we list the cost categories are eligible for § 376 treatment for costs incurred in 1997 and 1998 only, with the exception of UNIS costs. Only those actual costs incurred that are approved for reasonableness will be allowed § 376 treatment. We can accept the reasonableness of external implementation costs without further review. The external costs imposed by FERC through the grid management charge for the ISO and the initial charge for the PX can be easily and independently verified. The costs of our CEP and EET programs have been authorized by prior decisions and can be considered to be pre-approved. The cost categories eligible for § 376 treatment are the following:

- Start-up and Development costs of the ISO
- Start-up and Development costs of the PX
- PX Bidding Costs related to Default Load
- Market interface costs related to design, development, and testing
- Customer Education Program
- Electric Education Trust
- Processing DASRs
- Customer Service Requests
- ESP Support
- Overall project support for Direct Access
- Information Technology Infrastructure
- Employee Training
- Load Profiling
- Costs related to identifying and disclosing individual rate components (consistent with § 392)
- Customer Release Information for the Opt-Out Database

Voluntary Cap

Because we have strictly defined implementation, even without accounting for reasonableness or avoided costs and associated cost savings, we expect that the maximum costs that can be claimed for recovery will be well below $275 million. (Exhibit 6, Schedules 1B, 2B, and 3B, as updated.) This includes total ISO Grid Management Charges of $65.7 million, PX assessment charges of $45.4 million, CEP costs of $33.2 million, and EET costs of $7.1 million. Because we have defined implementation narrowly and consistent with § 376, we have diminished the need for Edison's voluntary cap on potential displaced generation-related transition cost recovery. We fully expect that our rigorous guidelines will ensure that displaced transition cost recovery will be minimal. We remind Edison that only the actual, reasonable implementation costs that comport with our guidelines will be allowed recovery.

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; 60 CPUC 2d at p.16.) 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.

These principles have been expressed across the industries that we regulate, particularly in telecommunications and energy. For example, in telecommunications, we have determined that only those costs caused by a cost object in the long run should be directly attributable to that cost object. In both telecommunications and energy, we have determined that "costs are considered to be caused by a cost object if the costs are brought into existence as a direct result of the cost object or, in the long run, can be avoided when the company ceases to provide the cost object. (D.98-12-079, mimeo., Appendix C, 63 CPUC2d 414, 463.) In D.97-09-047, we stated that "AB 1890's requirement that we should 'achieve the economic benefits of industry restructuring at the earliest possible date' implies that we should look for 'win-win' situations in which rates better reflect cost while at the same time collection of the CTC is accomplished as expeditiously as possible." (D 97-09-047 mimeo. at p. 20.)

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. 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 creation of the new competitive regime and therefore, consistent with cost causation principles, must bear the burden of these costs. The RAP is reviewing the accuracy of the calculation of the PX credit. We have addressed Enron's concerns regarding the costs included in energy procurement services by narrowly defining the costs eligible for § 376 recovery.

Eligible costs should be recovered through the TRA

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.

Edison's request to recover these costs in the TRA is reasonable. At the same time, Edison shall 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 to consider the necessity for extending CTC in A.99-01-016 *et al.*, the proceedings we have established to review post rate freeze ratemaking methodology. Once final costs are approved for § 376 treatment, headroom revenues should be allocated to these costs according to the principles established in the Revenue Adjustment Proceeding (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. Edison has converted cost estimates to a revenue requirement basis by developing a depreciation schedule for the capital expenditures and applying its non-generation rate of return of 9.49% to the rate base developed from the capital expenditures. Appropriate factors for franchise fees, uncollectible expenses, jurisdiction, state and federal income taxes, and other taxes are applied to both the capital and expense-related costs where applicable. Edison proposes a depreciation schedule based on depreciation rates adopted in its 1995 GRC (Exhibit 2, p. 80). For example, the depreciation rate or period related to capitalized software, computers, and office equipment is 5 years. Depreciation rates for communication equipment, meters, office furniture, and other items are much longer.

TURN and UCAN recommend that all capital-related § 376 costs should be amortized over the remainder of the transition period, should earn the reduced transition cost rate of return, and should be kept separate and apart from the distribution PBR mechanism. ORA generally agrees with Edison's proposed depreciation schedules, but recommends that a generic 20-year useful life be adopted for the package of software and hardware for any modifications to the Customer Information System proposed to receive § 376 treatment. ORA believes this is consistent with D.97-07-054, in which we adopted a 20-year useful life for the new CIS system installed by Southern California Gas Company (SoCal Gas).

Because capital costs have been incurred to accommodate implementation as of December 31, 1998, they should be treated as expensed items for ratemaking purposes. This is consistent with both tax and accounting practices and guidelines. For example, the Internal Revenue Service requires expenditures related to computer software development to be expensed even though their use or benefit may last more than one year. Accounting guidance for internal software development also allows the costs to be expensed instead of capitalized. In addition, we agree that certain capital projects may be undertaken for various functions, only some of which are eligible for § 376 treatment. 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. These costs will be carefully reviewed in Phase 2.

We agree with TURN that amortization of such eligible capital costs should not extend beyond the transition period. Because we define implementation as occurring as of December 31, 1998, there is no need to include capital costs for projects incurred for implementation in revenue requirements that may extend out as much as twenty or thirty years. This approach would result in intertemporal inequities and incorrect pricing signals. Since we are granting § 376 treatment only to those costs incurred in 1997 and 1998, we will require Edison to expense these items for ratemaking purposes, which then need not be grossed up for return and tax purposes.

Adopted Guidelines

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. In general, 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. However, the utilities may request § 376 treatment for 1999 eligible categories on a case-by-case basis. PG&E, Edison, and SDG&E must make a showing in new applications for reasonableness review of 1999 costs. PG&E, Edison, and SDG&E have the burden to demonstrate why such costs are necessary to accommodate implementation of the ISO, PX, and direct access in 1999.

3. Eligible 1997 and 1998 direct access implementation costs shall be reviewed for reasonableness, as shall 1999 direct access implementation costs on a case-by-case basis. Costs incurred for the start-up and development of the ISO, the PX, and the costs of 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. Approved capital-related restructuring implementation costs shall be recovered as expensed items for ratemaking purposes, when incurred, 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, and 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. Certain market interface costs related to design, development, and testing are also eligible for § 376 treatment. All customers should pay for these costs. Ongoing costs (whether expensed or capitalized) of PX operation and utility load bidding functions shall not be so eligible and must be recovered from market revenues.

11. No cost 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.

Edison should file a new application to address reasonableness reviews of costs determined to be eligible for § 376 treatment.

As determined in the scoping memo for this proceeding, we have delineated specific principles and guidelines for determining restructuring implementation costs that are eligible for § 376 treatment. The scoping memo stated that Phase 2 would address the reasonableness of eligible costs. Edison requests that we proceed expeditiously with Phase 2 and requests a decision by October 1, 1999. Edison acknowledges that it needs 4 to 6 weeks from the date of issuing the Phase 1 decision to file supplemental testimony. Edison also recognizes the work load and resource constraints of ORA and TURN and suggest that these constraints may be somewhat mitigated by the proposed settlement agreements in PG&E's and SDG&E's respective applications. Edison proposes a Phase 2 schedule based on the Phase 1 decision being issued by early February.

The Phase 1 proposed decision was mailed in mid-March, 90 days after submission. We have ordered Edison to undertake a detailed study of avoided costs and associated cost savings and to submit this study to facilitate reasonableness review of eligible costs for 1997 and 1998. We do not wish to compress the timeline necessary to proceed with Phase 2. We wish to ensure that Edison has sufficient time to conduct this study and to ensure that other parties have ample time to conduct discovery. Therefore, we direct Edison to file a new application to consider the reasonableness of 1997 and 1998 costs eligible for § 376 treatment, consistent with the guidelines provided in this decision. Because we have limited the implementation costs to those internal costs incurred in 1997 and 1998, any review of reasonableness can proceed expeditiously. We will allow Edison to request recovery of 1999 eligible costs that it contends are necessary for implementation. Edison must file a new application seeking reasonableness review of these costs and must clearly demonstrate why such costs are necessary to accommodate implementation of the ISO, PX, and direct access in 1999.

This approach resolves issues related to difficult forecasts and comparison among utilities, a contentious issue in this proceeding. ORA has concerns about embarking on reasonableness reviews in areas with few markers to guide us. Therefore, ORA proposes that all future costs be determined on a forecast basis, with the three utilities required to compare itself to the other two and to provide testimony explaining why it was necessary to exceed the lowest cost utility. We will allow recovery only for the actual, reasonable costs of eligible categories. We see no need for comparison among utilities, but will require each utility to make a convincing showing of the reasonableness of such costs.

Given the limited nature of this reasonableness review, we do not believe an independent audit is necessary, although we fully expect intervenors to carefully review these costs.

Clarification of Ex Parte Rules

Article 16 of our Rules of Practice and Procedure address rules concerning presiding officers. We take this opportunity to clarify our Rules 63.1 *et seq.*, which address petitions for reassignment of administrative law judges. On October 27, 1998, Edison informed ALJ Minkin by letter that Edison had initiated three contacts with Commissioner Bilas regarding the Notice of Reassignment in this proceeding, dated October 22. Edison characterized these contacts as procedural in nature, but sent the letter to all parties in the spirit of full disclosure. However, on November 3, ALJ Minkin explained that Rules 63.1 and 63.9, read together, prohibit all ex parte communications regarding the assignment or reassignment of particular ALJs. (RT: 1036.) ALJ Minkin requested Edison to file the appropriate ex parte notices. Edison complied with this request on November 12.

We affirm the ALJ's actions in this regard. Rule 63.1 provides that the provisions of this article are the exclusive means of seeking reassignment of a proceeding to another ALJ. Rule 63.9 prohibits ex parte communications regarding assignments and reassignments. Edison's concern about the timing of the commencement of evidentiary hearings and the Notice of Reassignment is immaterial. Ex parte communications regarding the assignment or reassignment of ALJs to particular proceedings are not procedural in nature. All such ex parte communications are prohibited. The only means by which petitions for reassignment can be sought are by the written procedures delineated in Rules 63.1 *et seq.*

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.98-05-015, Edison seeks to establish the eligibility of particular cost categories for which § 376 treatment is appropriate and the applicable ratemaking and rate recovery mechanisms.

3. Edison forecasts that approximately $430 million will be spent over the period 1997 to 2001 on restructuring implementation, as defined in § 376, but

voluntarily agrees to limit § 376 treatment to $275 million of that total and requests recovery of only actual, reasonable costs.

4. As directed in D.97-05-040, Edison established various subaccounts under the Industry Restructuring Memorandum Account (IRMA) to track these costs.

5. The costs associated with the ISO's start-up and development are recovered through the Grid Management Charge, which is a volumetric charge.

6. Edison's costs related to the start-up, development, and initial working capital costs of the PX comprise the initial charge payments by Edison, pursuant to a FERC tariff of the PX.

7. In a proposed settlement agreement pending before FERC, PG&E, Edison, and SDG&E would each pay a share of the initial charge payments in four installments, due on April 15, 1998, January 4, 1999, January 3, 2000, and January 2, 2001.

8. In addition to providing funding for the start-up and development costs of the ISO and the PX, Edison is incurring costs associated with procuring energy, which involves PX demand forecasts, bidding, and settlement, generation ISO/PX systems interface, and modifications to Edison's power systems controls systems and voltage support installations.

9. 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.

10. 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.

11. On September 14, 1998, an Assigned Commissioner's Ruling was issued that determined no further proceedings were necessary to determine

reasonableness of consumer education funding, since the CEP achieved the necessary awareness target of 60%.

12. In D.97-03-069, we found that funding the initial level for the Electric Education Trust (EET) was appropriate and approved § 376 recovery for such funding.

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

14. The objective of the Customer Service program is to enable Edison to respond fully to customer inquiries and requests related to electric restructuring. This includes processing Direct Access Service Requests (DASRs) from ESPs, responding to customer requests and inquiries regarding direct access, and providing ongoing operational assistance to ESPs.

15. Hourly interval meter installation and reading costs are costs incurred to accurately measure the hourly energy usage of direct access customers and to make this information available to other energy market participants for billing and settlement purposes, and include costs of developing load profiles for those customers who do not have interval meters.

16. Edison has developed particular energy cost accounting and retail billing systems to address interaction with the PX and the ISO.

17. The customer information release program consists of components for handling the release of confidential and non-confidential customer information.

18. Edison developed policies to guide its business units in determining whether programs would qualify under § 376. These policies are: the project must be necessary to implement restructuring; the activity and its costs must be incremental to existing authorizations; and employees, contractors, and capital projects must be exclusively related to implementing restructuring for their costs to be recorded in a § 376 account.

19. On July 1, 1998, Edison sent a letter to Senator Peace offering to voluntarily limit to $275 million the amount of utility generation-related transition costs it will seek to recover after the end of 2001, and agreed to limit its request for § 376 treatment of any future costs.

20. Edison's proposed cap includes Edison's share of the start-up costs of the ISO and PX (approximately $65 million and $45 million, respectively) and the costs of consumer education programs (approximately $40 million) and costs associated with providing direct access and revenue cycle services unbundling.

21. Edison contends that we have no authority to order Edison to accept a lower cap and that the record in this proceeding does not contain the substantial evidence necessary to limit the amount of costs subject to § 376 treatment.

22. Because a rate freeze is imposed, Edison recovers its transition costs through headroom revenues, that is, revenues are allocated from the total frozen rate levels to individual rate components, with the remaining balances identified as the CTC revenues.

23. Defining implementation for purposes of § 376 treatment is a pivotal determination in establishing our principles for cost eligibility.

24. 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.

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

26. Since March 31, 1998, the ISO has managed the power grid under its control, the PX has been operational, and consumers are opting to purchase electricity through direct access.

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

Certain eligible categories may receive § 376 treatment in 1999, but Edison must request such treatment in a separate application.

28. We will carefully evaluate restructuring costs to determine if the utilities incurred these costs 1) to establish the new market structure as of December 31, 1998, i.e., accommodate the implementation of the ISO, the PX, and direct access, 2) to operate as a distribution utility, or 3) to allow the utility to operate as a competitor in the new market structure.

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

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

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

32. 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.

33. Certain features of implementation may reduce costs for Edison.

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

35. Only those costs that are not recovered from any other source will receive § 376 treatment.

36. Edison's share of both the ISO and PX start-up and development costs are eligible for § 376 treatment.

37. 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.

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

39. EET costs are eligible for § 376 treatment.

40. All costs recorded in the ISO/PX and Other Wholesale Market Interface Costs subaccount of the IRMA are in addition to the start-up and development costs of the ISO and the PX. With the exception of costs necessary for the design, development, and testing of market interface systems and those costs associated with bidding default customer load into the PX, these costs are not eligible for § 376 treatment.

41. We must distinguish between the set-up costs of the PX and the operating costs of the PX.

42. Generation costs associated with the PX, including settlement costs, are not eligible for § 376 treatment, but must be recovered from operating in the market.

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

44. 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.

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

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

47. The 1997 and 1998 costs of DASR processing included in the Direct Access Implementation subaccount are eligible for § 376 treatment, to the extent these costs are determined to be reasonable in Phase 2.

48. The 1997 and 1998 reasonable costs of responding to customer requests and inquiries regarding direct access are eligible for § 376 treatment.

49. The costs of responding to and processing requests for interval meters and related metering services are costs of operating in the new world that should be recovered from market revenues and should not receive § 376 treatment.

50. The costs of handling customer complaints about ESPs, direct access, and restructuring are costs of operating in the new competitive market, as are customer requests to return from direct access to bundled utility service, and none of these costs should receive § 376 treatment.

51. For 1997 and 1998, reasonable costs associated with ESP support are critical services to ensure that the nascent competitive market is viable.

52. Costs incurred for ESP Provider Services are not required to implement direct access nor to foster the competitive marketplace, and must be recovered from market revenues.

53. Costs incurred for implementation support services in 1997 and 1998 will receive § 376 treatment for overall project management, information technology infrastructure, and employee training.

54. Costs incurred for direct access budgeting and control, auditing, and facilities development are not costs incurred to ensure implementation of direct access and should not receive § 376 treatment.

55. Costs incurred for meter-related activities under the Hourly Interval Meter Installation and Reading Costs subaccount are not necessary for and a part of the implementation of direct access, and will be incurred by other market

participants. Costs incurred for creating hourly load profiles are eligible for § 376 treatment.

56. Revenue cycle services result in additional retail competition in metering and billing.

57. Revenue cycle services are not eligible for § 376 treatment because they are not required to implement direct access.

58. Revenue cycle services are competitive services and the costs of providing such services must be recovered from the market.

59. In general, costs related to energy cost accounting and retail billing are part of the costs of operating in the new market. These costs must be recovered from market revenues and should not be eligible for § 376 treatment. However, costs related to identification and disclosure of individual rate components, consistent with § 392, are eligible for § 376 treatment.

60. Because implementation of the UNIS numbering system was delayed and because D.98-11-044 approved § 376 treatment for these costs, reasonable UNIS costs should be allowed § 376 treatment for 1999 only.

61. Only the reasonable costs of activities that the UDCs perform with respect to the opt-out list may be included for § 376 treatment, as provided for in D.98-03-072, because the opt-out list is a statutory requirement.

62. Direct access services that are discretionary and that are recorded in the Direct Access Discretionary Services Costs Memorandum Account are not required for implementation and are not eligible for § 376 treatment.

63. The determination of reasonableness for eligible cost categories will be made in future proceedings.

64. 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.

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

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

67. We have adopted stringent criteria for allowing § 376 treatment for restructuring implementation costs incurred to create the new market structure.

68. 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.

69. Edison's request to recover costs that are eligible for § 376 treatment in the TRA is reasonable.

70. Edison should record these § 376-eligible costs in a memorandum account to allow for comparison of displaced transition cost recovery, if any.

71. Once final costs are approved for § 376 treatment, headroom revenues should be allocated to these costs according to the principles established in the Revenue Adjustment Proceeding (RAP), A.98-07-006 et al.

72. 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.

73. 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.

74. To the extent capital costs are found reasonable and approved for recovery in Phase 2, we must determine how these costs should be amortized.

75. Because capital costs have been incurred to accommodate implementation as of December 31, 1998, for ratemaking purposes, they should be expensed during the transition period.

76. Certain capital projects may be undertaken for various functions, only some of which are eligible for § 376 treatment. It is incumbent upon Edison to delineate the costs of such capital projects between those costs eligible for § 376 treatment and those costs not so eligible.

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

78. Given the limited nature of the costs to be reviewed, an independent audit is not necessary.

Conclusions of Law

1. 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.

2. If the utilities fully recover their generation-related transition costs before December 31, 2001, § 376 treatment will not be required.

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

4. 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.

5. Limiting § 376 treatment to the reasonable costs of implementation of the PX, the ISO, and direct access in 1997 and 1998, and 1999 on a case-by-case basis, ensures that we are properly considering the intent of § 376.

6. 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.

7. 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.

8. 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 costs recovery.

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

10. Neither this Commission or the Legislature contemplated that recovery of the costs of competing in the new competitive generation marketplace would be funded by ratepayers.

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

12. Pursuant to D 97-12-042 and D 98-12-027, we have determined that costs incurred for the start-up and development of the ISO and PX are eligible for § 376 treatment, whether assessed as a one-time charge or as a volumetric charge.

13. 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.

14. 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.

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

16. 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.

17. 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.

18. 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.

19. DASR processing and creation of hourly load profiles are critical tasks in allowing implementation of direct access to begin.

20. Competition in metering and billing is not a goal in itself but a means to achieve effective competition in generation markets.

21. In D.98-09-070, we determined that we did not intend to allocate the incremental costs of unbundling revenue cycle services to the general body of ratepayers as a matter of fairness and consistent with sound pricing principles.

22. Section 392 requires the utilities to identify and disclose individual rate components on customers' bills.

23. Edison has the burden of proving that its costs are incremental and that all avoided costs have been quantified appropriately.

24. Because we have defined implementation narrowly, consistent with § 376, we have diminished the need for Edison's voluntary cap.

25. 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.

26. We have consistently recognized the importance of providing accurate price signals, and pricing based on the principle of cost causation.

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

28. We have prescribed specific guidelines for § 376 eligibility which will allow reasonableness reviews to move ahead expeditiously.

29. Costs incurred by Edison for the start-up and development of the ISO (paid through the grid management charge) and the PX (paid through the initial charge) are reviewed at FERC.

30. This Commission has pre-approved funding for costs of the Consumer Education Program and the Electric Education Trust.

31. Reasonableness reviews should be limited to reviewing the level of 1997 and 1998 eligible direct access implementation costs, and 1999 eligible direct access implementation costs on a case-by-case basis, that adhere to the principles delineated in this decision.

32. Edison should be directed to file a new application to request reasonableness review of its eligible 1997 and 1998 implementation costs. Edison should file a separate application to request reasonableness review of 1999 costs

eligible for § 376 treatment. Edison must clearly demonstrate and prove that these costs are necessary to accommodate implementation of direct access.

33. Consistent with our Rules of Practice and Procedure, ex parte communications regarding assignment or reassignment of ALJs are banned. Such ex parte communications are not procedural in nature and the exclusive means for seeking reassignment delineated in Rules 63.1 *et seq*. must be followed.

34. This order should be effective today in order to allow reasonableness review to proceed expeditiously.

INTERIM ORDER

IT IS ORDERED that:

1. The following guidelines are adopted for determining eligibility for Public Utilities 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. In general, 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. However, the utilities may request § 376 treatment for 1999 eligible categories on a case-by-case basis. PG&E, Edison, and SDG&E must make a showing in new applications for reasonableness review for 1999 costs. PG&E, Edison, and SDG&E have the burden to demonstrate why such costs are necessary to accommodate implementation of the ISO, PX, and direct access in 1999.

c. Eligible 1997 and 1998 implementation costs for direct access shall be reviewed for reasonableness, as shall 1999 direct access implementation costs on a case-by-case basis. 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. Certain market interface costs related to design, development, and testing are also eligible for § 376 treatment. 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.

2. The following cost categories are eligible for § 376 treatment, to the extent the cost obligation is incurred in 1997 and 1998, may be requested to receive § 376 treatment in 1999, and shall be reviewed for reasonableness:

a. Payments to the ISO for start-up and development costs;

b. Payments to the PX for start-up and development costs;

c. Payments to the CEP;

d. Payments to the EET;

e. Costs of developing systems to bid default customer load into PX;

f. Costs of developing market interface systems;

g. The 1997 and 1998 costs of Direct Access Service Request processing included in the Direct Access Implementation subaccount;

h. The 1997 and 1998 costs of responding to customer requests and inquiries regarding direct access, as recorded in the Direct Access Implementation subaccount;

i. The 1997 and 1998 costs associated with Energy Service Provider (ESP) support, as recorded in the Direct Access Implementation subaccount;

j. The costs incurred for implementation support services in 1997 and 1998 for overall project management, information technology infrastructure, and employee training, as recorded in the Direct Access Implementation subaccount;

k. The costs of creating hourly load profiles;

l. The costs of identifying and disclosing individual rate components on customers' bills, consistent with § 392; and

m. The 1997 and 1998 costs of activities that Edison perform with respect to the opt-out list, as recorded in the Customer Information Release Systems subaccount.

3. Edison shall identify and quantify all avoided costs associated with eligible restructuring implementation costs, so that costs savings can be considered in approving the reasonableness of costs eligible for § 376 treatment. Edison shall provide the methodology, workpapers, and results of this study in its application to consider reasonableness of the 1997 and 1998 implementation costs defined as eligible for § 376 treatment in this decision. If Edison requests § 376 treatment for these categories in 1999, Edison shall similarly quantify all avoided costs in its application for reasonableness review of 1999 costs.

4. Edison shall file a new application in order to review Edison's direct access implementation costs for 1997 and 1998 that are eligible § 376 treatment, and may file a separate application requesting reasonableness review of 1999 costs, consistent with this decision.

This order is effective today.

Dated ____________________________, at San Francisco, California.

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