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Decision 97-12-093 December 16, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PacifiCorp (U901-E) For Approval of PacifiCorp's Transition Plan.	Application 97-05-011 (Filed May 5, 1997)
Application of Sierra Pacific Power Company for Approval of its Transition Plan.	Application 97-06-046 (Filed June 27, 1997)
Application of Kirkwood Gas & Electric Company (U906-E) For Compliance with the Requirements of AB 1890.	Application 97-07-005 (Filed July 3, 1997)
Application of Southern California Water Company for Certain Exemptions to California Public Utilities Commission Decisions 97-05-039, 97-05-040, and Related Order Instituting Rulemaking (OIR) 94-04-031, and Order Instituting Investigation (OII) 94-04-032.	Application 97-08-064 (Filed August 22, 1997)

(See Appendix A for list of appearances.)

ORDER ADDRESSING THE APPLICATION OF AB 1890 TO SMALLER AND MULTI-JURISDICTIONAL ELECTRIC UTILITIES

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ORDER ADDRESSING THE APPLICATION OF AB 1890 TO SMALLER AND MULTI-JURISDICTIONAL ELECTRIC UTILITIES

Summary

In September 1996, the Governor signed into law Assembly Bill (AB) 1890, which sets forth the framework under which California's electrical corporations will move toward and function within a restructured electric industry. As defined in Public Utilities (PU) Code § 218(a), there are seven electrical corporations currently doing business in California that are subject to our jurisdiction:

Pacific Gas and Electric Company (PG&E)

San Diego Gas & Electric Company (SDG&E)

Southern California Edison Company (Edison)

Southern California Water Company's Bear Valley Electric (Bear Valley)

Kirkwood Gas & Electric Company (Kirkwood)

PacifiCorp

Sierra Pacific Power Company (Sierra)

PG&E, SDG&E, and Edison have comparatively large service territories within California. AB 1890 contains many specific references to each of these companies. Bear Valley and Kirkwood are comparatively small companies that serve recreational areas. Bear Valley owns no electric generation facilities, and Kirkwood has no transmission facilities and is not connected to the regional transmission grid. PacifiCorp and Sierra are multi-state utilities that conduct a small fraction of their retail electric business in California. AB 1890 does not mention, by name, any of the four smaller and multi-jurisdictional electrical corporations.

No one denies that at least some of the provisions of AB 1890 apply to the smaller and multi-jurisdictional utilities, since the bill refers to all electrical corporations as defined in PU Code § 218(a). At issue, here, is whether we can or should relieve a utility of the need to comply with provisions of AB 1890 where the utility can demonstrate the existence of special circumstances. We find nothing in the statute that would allow for a less-than even-handed application of its major provisions to all electrical corporations. Where the Legislature wished to carve out exceptions, it did so explicitly. We are not free to create exceptions where the Legislature has provided for none. Thus, each of these companies is required to unbundle its rates into components that reflect its underlying cost for generation, transmission, distribution and public purpose programs. Where a company is seeking to recover any uneconomic cost of generation, it must reflect the resulting transition charges on its bills to all customers, track its collection of transition costs in a balancing account, undergo a market valuation process, surrender control of its jurisdictional transmission facilities to the Independent System Operator (ISO), freeze its rates at June 10, 1996 levels and provide a 10% rate reduction for residential and small commercial customers. A company that does not seek the recovery of uneconomic costs has no transition period. Its rates need not be frozen and it need not offer a 10% rate reduction. However, such a company forgoes its opportunity to collect transition costs and must charge its bundled customers for the market cost for providing generation services, as opposed to its embedded cost.

Also at issue in this proceeding is whether any or all of the applicants should be required to collect surcharge funds for energy efficiency and low-income assistance programs and to pay these surcharge funds to the California Board for Energy Efficiency and the California Low-Income Governing Board for the administration of statewide programs. We require all applicants to continue funding at 1996 levels, but do not force any of the applicants to enter into new expenditures at this time.

Background

PacifiCorp filed what it calls its Transition Plan on May 5, 1997. Sierra filed a similarly-named application on June 27, and Kirkwood filed its plan on July 3. On August 22, Bear Valley filed an application in which it requested exemption from various requirements set forth in earlier Commission decisions related to the electric restructuring process. Prehearing conferences were held on August 13, 1997 and September 9, 1997. At the direction of the assigned administrative law judge (ALJ), the active parties filed a Case Management Statement on August 29, 1997. The assigned

Commissioner and assigned ALJ jointly ordered the applicants to submit supplemental showings on August 21, 1997 to demonstrate how each would modify its Transition Plan to make it consistent with the Commission's decision unbundling the rates and revenues for PG&E, SDG&E, and Edison (Decision (D.) 97-08-056). The parties filed an early round of briefs on September 8, 1997 and September 15, 1997, addressing specific issues of statutory interpretation related to PU Code § 368, 381, and 382. Testimony was filed on October 1, 1997 and evidentiary hearings were held on October 8, 9, and 10, 1997. On October 8, 1997, PacifiCorp and Office of Ratepayer Advocates (ORA) signed a stipulation under which they agree to support a given resolution of most issues affecting PacifiCorp in this proceeding. They acknowledged a continuing disagreement as to whether or not PacifiCorp must reduce its rates for residential and small commercial customers by 10%. The consolidated matters were submitted with the receipt of post-hearing briefs on October 24, 1997. A proposed decision was mailed November 13, 1997. Parties filed comments on the proposed decision on December 3, 1997[1] and reply comments on December 8, 1997. Where appropriate, we have made changes to the proposed decision in response to comments.

Discussion

Direct Access Proposals

A. Implementation of Direct Access

Each of the applicants has pledged to provide its customers with direct access to the services of competing energy providers beginning January 1, 1998. PacifiCorp, Sierra and Bear Valley submitted Direct Access Implementation Plans for approval in our electric industry restructuring docket which were approved in D.97-10-087.

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[1] There are various motions to accept late-filed comments. All such motions are granted.

Coordinating Commissioner Conlon granted Kirkwood an exemption from filing a separate Direct Access Implementation Plan because of its unique circumstances:

> "As it notes in the motion, Kirkwood serves only 417 customers, and only about 75 year-round residences. One customer, the ski resort and related facilities, accounts for more than half its demand. It has no transmission facilities and is not interconnected with any other utility. All of its power is generated on-site using diesel generators. It has no employees because all work is provided on a contract basis. It has no contracts with qualifying facilities."

To facilitate direct access, Kirkwood will offer unbundled rates to its customers and pledges to make its distribution system available to competing energy providers. However, because there are no apparent avenues to competition, it is premature to require Kirkwood to submit a detailed direct access plan.

B. Unbundling of Bills and Services

In D.97-08-056, we concluded that PG&E's, SDG&E's, and Edison's bills should separately identify amounts related to energy, transmission, distribution, competitive transition charges, public purpose programs and nuclear decommissioning costs (see mimeo., pp. 52-53). However, because of the time needed to prepare the billing systems to provide this level of detail, we directed the utilities to include these separate charges in their bills no later than June 1, 1998. Prior to that date, those utilities are only required to provide information about Power Exchange (PX) prices.

PacifiCorp proposes to separately identify charges on its bills for distribution, transmission, public purpose programs and generation. Instead of providing one charge for generation, the bill would list two components: (1) a monthly market-based charge (based on the Dow-Jones California-Oregon Border electric price index) and (2) the rate reflecting the balance of the generation revenue requirement. Its customers who elect direct access would still be required to pay the second generation charge. In other words, they would receive a bill credit based on the Dow-Jones index. In its stipulation with PacifiCorp, ORA supports this proposal. Under the stipulated proposal, the bill would also contain a credit for transmission and ancillary cost savings, where applicable. PacifiCorp would not separately indicate its competitive transition charge (CTC) on its bill. In effect, the generation charge, minus the Dow-Jones index credit, would constitute a transition charge.

Sierra offers a similar proposal, although its energy credit would be based on PX prices. Bear Valley, which owns no generation or transmission facilities, proposes to separate its charges into distribution, power system delivery charges, energy and public purpose programs. Since it would be recovering no transition costs, its bill would not include that category. Kirkwood would unbundle the generation and distribution components of its bills. Since it has no transmission cost or public purpose programs, its bills would not identify these charges. None of the applicants face nuclear decommissioning costs.

Section 368(b) requires, in part:

> "...identification and separation of individual rate components such as charges for energy, transmission, distribution, public benefit programs, and recovery of uneconomic costs. The separation of rate components required by this subdivision shall be used to ensure that customers of the electrical corporation who become eligible to purchase electricity from suppliers other than the electrical corporation pay the same unbundled component charges, other than energy, a bundled service customer pays."

In addition, § 392(a), as amended in Senate Bill (SB) 477, states that each company's electrical bills must disclose CTCs. The billing approaches proposed by PacifiCorp and Sierra fail to meet the requirements of these sections because they would not separately identify charges related to the recovery of uneconomic costs. This aspect of the transition plan for each of these two companies is rejected.

Under their proposals, these companies would recover uneconomic costs when the indexed generation credit is less than the embedded cost of generation. In such circumstances, by paying a residual generation charge, direct access customers would be compensating the utilities for the uneconomic portion of their embedded costs. By extension, fully bundled customers also would be compensating the utilities for uneconomic generation. The unambiguous requirement of the statute is that all customers be informed of the portion of their charges that reflect recovery of uneconomic costs.

This is more than an issue of aesthetics. After the end of the transition period, the uneconomic generation costs will not be part of the cost faced by customers. In order to understand the risks and benefits of direct access, customers must be fully informed of the charges that they stand to avoid and those that they cannot avoid. Only the most savvy customer might be able to look at the bill as proposed by PacifiCorp and Sierra and recognize that the residual generation charges would no longer be an issue after the transition period. In addition, the provisions of AB 1890 and SB 477 ensure that the accelerated repayment policy reflected in transition charges will be transparent to all ratepayers. To achieve this result, the transition charges must be clearly stated on the bills of all customers, bundled or otherwise, and the rates for all customers must be fully unbundled by function.

We have allowed PG&E, SDG&E, and Edison a grace period of five months before they must bill their customers in a manner that directly reports on all required unbundled elements. Similarly, we will allow PacifiCorp and Sierra to employ their proposed market index credit approach until June 1, 1998. As of that date, bills for all of their customers must include a separate accounting for the full embedded cost of generation and competitive transition charges. As of that date, direct access customers must not be billed for generation, even as a residual amount. Instead, the difference between the embedded cost of generation and the relevant market index shall be reported as a competitive transition charge. If a company does not collect transition charges, however, it need not include an item for competitive transition charges on its bills.

Because PacifiCorp's generation and transmission system is centered in other states, it is reasonable to allow them to use a region-specific energy price index such as the COB. However, the record suggests that the COB in its current form does not capture the full range of ancillary and other costs that would be faced by customers acquiring electric energy in the competitive market. The Power Exchange price, on the other hands, is a market-derived price and reflects those costs. Until PacifiCorp can propose a way to include all relevant costs in the COB price, or proposes another more complete market proxy, we will direct the company to rely on the monthly average Power Exchange prices to develop its bill credit.

In D.97-05-039, we determined that competing retail electric service providers should be allowed to offer their customers consolidated billing for electric services, meters, meter reading and related services. To simplify our discussions, we have referred to these as revenue cycle services. In that decision, we concluded that PG&E, SDG&E, and Edison must separately identify the cost savings resulting when these services are provided by others and make those savings available to ratepayers through separate charges or credits. We also required that competitive retail providers enter into agreements with distribution utilities concerning the collection and exchange of usage data. In its application, Bear Valley makes an unsupported request for exemption from these unbundling requirements. The other applicants appear to be silent on this issue.

We see no reason that competing energy providers should face different conditions when offering to serve the customers of these applicants than they face when seeking to serve the customers of PG&E, SDG&E, or Edison. We have required the latter three companies to offer unbundled revenue cycle services by January 1, 1999 and will place a similar requirement on most of these applicants. By February 1, 1998, PacifiCorp, Sierra and Bear Valley will be required to file proposals for unbundling and separately charging for these services. In the meantime, they must begin to accommodate third-party meters and metering services consistent with D.97-05-039 and be ready to enter into service agreements with competing firms. We will defer such a requirement for Kirkwood until the likelihood of competition within its service territory suggests the need for the company to submit a direct access implementation plan.

ORA raises one concern about Bear Valley's proposal for unbundling its rates. As a distribution-only utility, Bear Valley offers direct access customers a bill credit for energy, but not for the cost of ancillary services. Ancillary services include system protection services, line losses and energy imbalance services. Energy imbalance services ensure that a direct access customer will be furnished with electricity even when the competing energy firm fails to deliver power to the grid. Its current contracts require Bear Valley to take all generation capacity from Edison, but do not require it to acquire ancillary services from Edison. ORA proposes that Bear Valley separately identify its cost for ancillary services (and identify them as transmission costs) so that direct access customers wishing to purchase those services elsewhere would receive a bill credit and that Bear Valley's tariffs should clarify that non-firm power purchases by its customers would be made firm by its contract with Edison. Bear Valley has not expressly opposed this proposal, which appears to be a sensible means to help customers take into account an apparently avoidable portion of the transmission expense. We will direct Bear Valley to separately identify, and credit to the bills of qualifying direct access customers, its ancillary costs, and to clarify the feasibility of non-firm power purchases in its tariffs.

C. Consumer Education Plans

We approved Consumer Education Plans for PacifiCorp, Sierra, Bear Valley and other electric utilities in D.97-08-063 and will not modify or otherwise address the adopted programs here. Kirkwood has made its proposal for consumer education expenditures here. No one has objected to that proposal and it should be approved. In its comments to the proposed decision, Kirkwood suggested that it be required to begin its program on March 1998. This date appears reasonable in light of the date of this order.

D. Public Purpose Programs

Section 381 directs the Commission to allocate electric utility revenues to programs that enhance system reliability and provide in-state benefits in the form of cost-effective energy efficiency and conservation activities, public interest research and development, and in-state operation and development of renewable resource technologies such as photovoltaics. It also specifies that all electric utilities must identify on their bills a separate rate component for these purposes and must insure that funds for these programs are not commingled with other revenues. Under this section, the Commission is also empowered to develop a system for managing these funds. We responded to this portion of the statute in D.97-02-014, by establishing boards to oversee these programs. Section 381 sets forth specific, minimum funding levels for PG&E, SDG&E, and Edison. However, it provides no specifics for any of the four companies that are the subject of this proceeding.

The Residential Energy Services Companies' United Effort and SESCO, Inc. (RESCUE/SESCO) argue that § 381 requires each electrical corporation to collect surcharges for these programs and grants the Commission the discretion to determine the appropriate level of funding. RESCUE/SESCO advocate that whatever funds are collected by the applicants be submitted to the oversight boards for allocation on a statewide basis. In addition, RESCUE/SESCO suggest that each applicant be required to increase its funding level for these programs so that its ratepayers bear an equitable share of the statewide funding for these purposes.

Although AB 1890 is silent about the appropriate funding level for these applicants, it is specific as to the minimum funding levels for every other electric utility in California. In D.97-02-014, we approved funding for PG&E, SDG&E, and Edison at the minimum levels allowed under § 381(c), while indicating that we may consider increasing those funding levels at a later time. Section 385(a) states that each municipal electric utility must match, as a percent of total revenues, the lowest level of funding established for PG&E, SDG&E, or Edison. RESCUE/SESCO argue that there is no reason to suggest that the Legislature intended to require funding of these programs by all ratepayers in California except those served by PacifiCorp, Sierra, Kirkwood, and Bear Valley. As a matter of fairness, RESCUE/SESCO argue, ratepayers of these utilities should at least match the contribution level required by the ratepayers of the municipal utilities which, based on the approved level of funding for Edison (the lowest level of the three larger California utilities), would equal 2.74% of total revenues.

Currently, Kirkwood and Bear Valley have no funds allocated to these types of programs. Sierra devotes $214,033 to energy efficiency and low-income assistance programs. This is approximately 0.5% of Sierra's California revenue requirement. In

1996, PacifiCorp devoted approximately 0.75% of its revenues to energy efficiency and low income programs.

We do not interpret § 381 as requiring that we adopt a new funding level for any of the applicants. The statute requires that any charges related to these programs be separately stated on the customer's bill and directs us to determine and adopt funding levels for PG&E, SDG&E, and Edison. However, it offers us no direction related to the applicants in this proceeding.

We are left with concerns of equity and fairness to guide our determination. As a matter of equity, it is reasonable that programs such as these, which are intended to provide statewide benefits, should also be supported by all ratepayers. It is puzzling as to why the Legislature would prescribe minimum funding levels for every other utility in the state, but ignore these applicants. However, that is what it did. It must be presumed that if the Legislature intended that we treat funding levels for the applicants in a manner consistent with the other utilities, it would have said so. While we remain free to direct the applicants to spend more on these programs, it would not be fair to do so for all utilities now.

Bound in the frozen rates for PacifiCorp and Sierra is the assumption that funds for these programs would remain at current levels. These two utilities provide power to California ratepayers at comparatively low rates. We will not erode the otherwise-available headroom for these utilities by requiring new expenditures at this time. We will, however, require that funds at current levels be submitted to the appropriate oversight boards for distribution.

ORA proposes that Bear Valley, which also devotes funds to its California Alternative Rates for Energy Program (CARE, discussed below), cumulatively devote 0.5% to 1.0% of its revenues to the four public purpose program areas. Bear Valley supports this proposal. Adding its existing CARE commitment and its proposed allocation for research and renewable resources, we find that it is reasonable for Bear Valley to devote 1.4% of its revenues to public purpose programs. Because of its exceedingly small customer base, we will not create a public purpose funding requirement for Kirkwood on the basis of its existing revenue requirement. We will consider adjusting the revenue requirement for Kirkwood to provide funds for these programs in any future rate case and will consider increasing Bear Valley's funding, as well.

Section 382 requires that electrical corporations continue to fund programs provided to low-income electricity customers, including, but not limited to, targeted energy-efficiency services and the CARE program at not less than 1996 authorized levels based on an assessment of customer need. We are expressly directed "to allocate funds necessary to meet the low-income objectives in this section." We read this language to require that all current low-income efforts continue at least at the current funding levels, and that if customer need exceeds current funding levels, those levels should be increased.

PacifiCorp proposes continuing to fund low-income programs at current levels. In addition to the energy efficiency and low-income funding mentioned earlier (0.75% of annual revenues), PacifiCorp devotes 1% of its revenues to the CARE program. Sierra also proposes to maintain funding at current levels. Combined, expenditures on its energy efficiency and CARE programs comprise approximately 0.5% of its annual California revenues. Bear Valley allocates 0.5% of its revenues to the CARE program. Kirkwood allocates none, but offers a special case because of its small customer base, predominance of second-home owners and limited revenues.

Consistent with § 382, we will require PacifiCorp, Sierra, and Bear Valley to maintain their current levels of funding for low-income and CARE programs. These funds should be submitted to the Low Income Governing Board for further disbursement. For the reasons discussed above, we conclude that it would be inappropriate to increase these funding levels now. We will not require Kirkwood to allocate funds to the CARE program because of the small amount of revenues that it would generate compared to any likely administrative costs (1% of its revenue requirement is $2,200) and the apparently minimal number of low-income customers in its service territory. Any such customers should be eligible to receive benefits under a statewide program, but because there are likely to be few in Kirkwood's service territory, they should provide an insignificant impact on statewide funding.

Some parties have recommended that whatever funds are set aside by the companies for public purpose programs be divided evenly among the four program areas. RESCUE/SESCO argue that it is most important to preserve adequate funding for low-income and energy efficiency programs. We agree, since the level of low-income funding should be related to need and because cost-effective energy efficiency programs provide immediate benefits both to the individual recipient and to society as a whole. We will direct PacifiCorp, Sierra, and Bear Valley to maintain the current level of funding for low-income, energy efficiency, and CARE programs and to allocate the remaining funds evenly across the two remaining public purpose program categories. In all cases, the funds should be transferred to the appropriate oversight board for disbursement.

We direct the Low-Income Governing Board (LIGB) and the California Board for Energy Efficiency (CBEE) to plan to include in their Requests for Proposals for new administrators consideration of the funds and programs of these utilities and to work with the companies to create a transition schedule in concert with the transition mandated by the Commission for PG&E, SDG&E, and Edison. For Research Development & Demonstration and renewable funding, the companies should work with the California Energy Commission (CEC) on a transition schedule. Within 30 days, in Rulemaking (R.) 94-04-031 and Investigation (I.) 94-04-032, the utilities should file (jointly with the LIGB, CBEE, and CEC) proposed transfer mechanisms and milestone schedules that are consistent with those adopted for PG&E, SDG&E, Edison and Southern California Gas Company. These proposals shall be served on the parties listed on the Special Public Purpose Service List in those dockets. Parties will then have 10 days in which to file comments, which should also served on those on the Special Public Purpose Service List.

In R.94-04-031/I.94-04-032, we directed CBEE and LIGB to recommend a forum and schedule for reassessing initial program funding levels for PG&E, SDG&E, Edison, and Southern California Gas Company. (See Assigned Administrative Law Judge Rulings dated October 27, 1997 and November 13, 1997.) We believe that our future reassessment of public purpose program funding for PacifiCorp, Sierra and Bear Valley should take place in the same forum we identify in response to CBEE's and LIGB's recommendations. Consistent with the treatment we have adopted for other utilities, the applicants should reserve no less than 15% of their 1998 energy efficiency funds for use by a new administrator for start-up purposes. Similarly, those applicants with low-income energy efficiency or direct assistance programs should be prepared to cover start-up costs in a manner consistent with that adopted for other utilities.

E. Independent System Operator

On October 30, 1997, the Federal Energy Regulatory Administration (FERC) issued a decision authorizing the operation of the California ISO. Under § 9600(b), following FERC approval of the ISO, no California electrical corporation shall be authorized to collect any CTC unless it commits control of its transmission facilities to the ISO. This intention is underscored in § 330(m). This requirement does not apply to Kirkwood or Bear Valley, who have neither transmission facilities nor a plan to recover any transition costs. However, it does apply to both PacifiCorp and Sierra. Each owns and operates transmission facilities in California and (as we will discuss below) each anticipates experiencing uneconomic generation-related costs and hopes to recover at least some of those costs through transition charges.

The statute is unambiguous in stating that, under these circumstances, PacifiCorp and Sierra must commit control of their California transmission facilities to the ISO, but provides no guidance as to what it means to commit control. PacifiCorp expresses a willingness to operate its California transmission facilities under the direction of the ISO but expresses a preference to submit to the control of the planned Northwest Independent Grid Operator (IndeGO). In addition, by January 1, 1998, PacifiCorp expects to complete an inter-control area agreement with the ISO. PacifiCorp suggests that an inter-control area agreement will address the same activities as the ISO's actual assumption of control over the facilities and that by doing so, PacifiCorp will have submitted to the control of the ISO.

Sierra states that it cannot risk the possibility that the ISO would take physical control of its California transmission facilities. Close to 95% of Sierra's transmission system crosses northern Nevada. Under normal circumstances, all of the company's California customers receive transmission services from Nevada. Sierra asserts that in order to function reliably, a substantial portion of its energy must be supplied from generation located in northern Nevada and that purchased power from California, or elsewhere outside of northern Nevada cannot exceed a certain limit. Sierra is also negotiating an inter-control area agreement with the ISO.

Enron states that it does not matter who has physical control over these transmission systems, so long as the control is comparable to that exercised by the ISO for other transmission facilities in California. They suggest that the goal should be to ensure that all customers have the opportunity to choose direct access and that all energy service providers have comparable access to transmission and distribution facilities of regulated utilities. We agree that these goals are at the heart of the requirement that the utilities surrender control to the ISO.

The record indicates that the ISO has found that it would be impractical for it to take control over PacifiCorp's and Sierra's transmission facilities and that it is, instead, seeking to finalize operating agreements with these firms. These actions appear consistent with the statutory requirement of committing control to the ISO. It is for the ISO to determine the best way to ensure that direct access customers and suppliers can gain access to each other across the transmission systems owned by PacifiCorp and Sierra. However, we agree with Enron that, consistent with § 9600 (b), if the ISO should later decide that it is practical to assume control of their transmission facilities, both PacifiCorp and Sierra must comply. Finally, in order to ensure "seamless" access for customers, we adopt Enron's suggestion that both PacifiCorp and Sierra be required to modify their respective FERC transmission tariffs no later than thirty days after the ISO and transmission owners tariffs are approved by FERC.

F. Power Exchange

In its Preferred Policy Decision (D.95-12-063, as modified in D.96-01-009), which preceded the enactment of AB 1890, the Commission ordered PG&E, SDG&E, and Edison to sell all of their generated power to the PX and to buy all energy required to serve full service customers from the PX until the end of the transition period. In the Second Roadmap Decision, D.96-12-088, we concluded that AB 1890 is silent on this point and that the mandatory buy/sell requirement remains in place. The applicants, here, propose neither to sell to, nor necessarily buy from, the PX. Kirkwood could neither buy from nor sell to the PX, since it is not connected to the transmission grid. Bear Valley has no generation to sell, is committed to buy its capacity from Edison and purchases all of its energy requirement on the open market. Both PacifiCorp and Sierra serve their customers with a mix of power from generating plants that are primarily located outside of California. The complexities of multi-state service and regulation suggest that it may be impractical or counter-productive to require either of these companies to sell to or buy from the PX. Thus, we are not prepared to impose a mandatory buy/sell requirement on any of the current applicants.

The transactions of the PX remain of interest because of the need to use a marketplace benchmark to calculate transition costs and charges. Below, we will address the role of Power Exchange prices in making those calculations.

Issues Related to Cost Recovery

A. Cost Recovery for Ongoing Obligations and Direct Access Implementation

The transition period, which is to end no later than December 31, 2001, marks the last date for the recovery of most transition costs. Consistent with §§ 367(a)(2) and 376, PacifiCorp and Sierra seek authority to recover costs after the end of the transition period that are related to direct access implementation (to the extent such costs reduce the utility's opportunity to recover utility generation-related plant and regulatory assets and have been found reasonable by FERC or this Commission after 2001) and uneconomic costs stemming from ongoing obligations (such as contracts for purchases from qualifying facilities (QFs) under the Federal Public Utility Regulatory Policies Act). These requests are appropriate under the statute and consistent with our treatment of PG&E, SDG&E, and Edison. As Sierra has pointed out, the recovery after December 31, 2001 of costs stemming from ongoing obligations is limited to costs incurred after that date. Sierra and PacifiCorp are authorized to maintain appropriate balancing accounts for these purposes. Bear Valley also will continue to track its direct access implementation costs in its Industry Restructuring Memorandum Account. However, Bear Valley will not have a transition period and must seek recovery of reasonable amounts in those accounts in subsequent rate cases.

B. Performance-Based Ratemaking

PacifiCorp has a Performance-Based Ratemaking (PBR) plan currently in effect, scheduled to expire on December 31, 1999. The company plans to apply for a new PBR mechanism to apply to its distribution function to become effective January 1, 2000. None of the other applicants have approved PBR mechanisms in place. In D.96-12-084, we approved a settlement between Sierra and ORA which extended a rate freeze that was then in effect and required Sierra to file a new general rate application and PBR proposal to take effect after the rate freeze. We will direct PacifiCorp to file a new distribution PBR proposal no later than December 31, 1998 and Sierra to file a distribution PBR proposal no later than December 31, 1999. No party has proposed that we pursue the use of PBR mechanisms for Kirkwood or Bear Valley and it is logical to assume that for these unique companies, broader assumptions about the efficacy of a PBR mechanism may not apply. In subsequent rate proceedings for those companies, we will consider the appropriateness of pursuing some form of PBR in the future.

C. Rate Freeze

Section 368 requires an electrical corporation that is seeking to recover uneconomic generation costs to file a cost recovery plan which must, among other things, set rates for each customer class, rate schedule, contract, or tariff option, at levels equal to the level as shown on electric rate schedules as of June 10, 1996. It also requires that such utilities reduce rates for residential and small commercial customers by at least 10% from those levels. These rates must stay in effect until the end of the transition period. As will be discussed below, these requirements apply to PacifiCorp and Sierra so long as they are seeking to recover uneconomic costs. They do not apply to Kirkwood and Bear Valley, which are not seeking the recovery of uneconomic costs and therefore do not have a transition period. Since the transition period for Kirkwood and Bear Valley ends before it begins, neither firm is required under § 368 to enter into or maintain a rate freeze.

D. Transition Cost Recovery

1. *Definition and Requests*

Transition costs are "the uneconomic generation-related assets and obligations" listed in §§ 367 and 840(f), reasonable and necessary capital additions (§§ 367, 840(f)), and certain employee-related costs (§ 375; *see* § 367(a)(1)).

Kirkwood is not seeking transition cost recovery and, as discussed elsewhere, the rate freeze and the 10% rate reduction provisions of the legislation are not applicable. Similar principles apply to Bear Valley.

In their applications, PacifiCorp and Sierra have sought some form of transition cost recovery. PacifiCorp has entered into a stipulation with ORA on some components of PacifiCorp's cost recovery plan. PacifiCorp intends to freeze rates over the transition period, but would not seek explicit transition cost recovery during the rate freeze period. Instead, customers electing to purchase power from direct access providers will receive a credit on their bills equal to the wholesale market price of electricity in relevant markets. PacifiCorp proposes to use the Dow-Jones California-Oregon Border (COB) electric price index, as the basis of its market price credit. If this market credit is less than the embedded cost of generation included in the current tariffed prices, PacifiCorp proposes to retain this differential to offset transition costs. If the market credit is greater than the embedded cost of generation, the residual component would be negative, i.e., PacifiCorp would not collect CTC and would essentially refund to direct access customers any stranded benefits associated with its system. Full service customers would continue to pay frozen rates through 2001 or until the rate freeze ends. Following the transition period, PacifiCorp proposes to implement a specific CTC, effective January 1, 2002, for recovery of ongoing obligations which become uneconomic as a result of competition in the generation market. These anticipated costs consist of the above-market costs of QF and power purchase contracts and any restructuring implementation costs that reduce PacifiCorp's opportunity to recover costs addressed in § 376. PacifiCorp is not seeking recovery for employee-related transition costs, nor, as outlined in the stipulation with ORA, any regulatory assets.

2. *Discussion of Headroom and Transition Cost Recovery Approach*

ORA supports this aspect of PacifiCorp's proposal. Specifically, ORA recommends that the Commission should find that because PacifiCorp and Sierra Pacific are requesting recovery of uneconomic costs, these utilities must also implement a rate freeze and a 10% rate reduction for residential and small commercial customers. ORA recommends that headroom be defined as the difference between frozen rate levels and the utility's own operating costs as represented by the Power Exchange clearing price. ORA recommends that we approve the transition plans of PacifiCorp and Sierra in a manner which approves their opportunity to recover ongoing contractual obligations and direct access implementation costs after 2001, consistent with the requirements of AB 1890.

We do not agree with PacifiCorp's and Sierra's approach to transition cost recovery for several reasons. Section 367 specifically requires this Commission to determine which costs may become uneconomic in the new competitive market. Unfortunately, there is no latitude provided in the legislation for the small and multi-jurisdictional utilities. Although PacifiCorp and ORA have agreed that freezing rates as of June 10, 1996 and using the California-Oregon electric price index as the basis of the market price credit yields an estimate of uneconomic transition costs, we cannot rely on this estimate in determining those costs which may become uneconomic. While there are certainly aspects of the small and multi-jurisdictional utilities that are unique, to the extent such utilities are seeking transition cost recovery, we will apply principles and guidelines which we have previously determined to be consistent with the law and essential for the transition cost recovery of PG&E, Edison, and SDG&E.

Each utility seeking transition cost recovery must establish a transition cost balancing account. First, § 367(d) requires that uneconomic costs "be adjusted throughout the period through March 31, 2002, to track accrual and recovery of costs." Second, these balancing accounts are essential in the determination of what ultimately are considered uneconomic costs. As ORA correctly observes, we cannot know whether headroom is insufficient to pay for uneconomic costs at this time. The determination of transition costs has several steps. The utilities must establish a balancing account to properly track eligible transition costs and applicable revenues. This Commission must determine the cost categories that are eligible for transition cost recovery. Finally, we must determine whether or not such costs and cost categories are uneconomic, based either on market valuation or a comparison of ongoing costs with the PX market-clearing price or other acceptable market index.

We have reiterated many times that we prefer a market-based approach to determining transition costs. This observation holds true for the multi-jurisdictional utilities, as well as the three major utilities. We have determined that there is no need to forecast total transition costs at this point, because we cannot yet acquire correct information about the market-clearing price, or about market valuation. We obviously do not have the same market power concerns for PacifiCorp and Sierra that we did for PG&E, Edison, and SDG&E. Section 367(b) requires those assets subject to valuation to be market valued by December 31, 2001. Again, there is no language exempting PacifiCorp and Sierra from this requirement. We are persuaded that even an appraisal of those assets that serve California customers would be a costly undertaking and would not necessarily add significantly to our understanding of uneconomic costs at this time. The more prudent course is to wait until the states in which these multi-jurisdictional utilities operate undertake electric restructuring. We presume that recovery of stranded assets would be a key element of any such proposals or law, as it has been in most other states and in the Federal effort to promote electric restructuring. We also assume that such efforts will be well on their way by year-end 2001. We order PaficiCorp and Sierra to establish transition cost balancing accounts which will track transition costs and transition cost recovery and are established in sufficient detail to track market valuation on a plant-specific basis. In addition, we order these companies to report to us no later than July 1, 1998 with a proposed mechanism for establishing market values for their generation assets. We would prefer that this plan rely on the regulatory approach adopted in each utility's dominant state, but will require that an independent effort be undertaken if the processes adopted elsewhere will not produce timely information.

Headroom is defined as the difference between the frozen rate levels as of June 10, 1996 and the utilities' reasonable costs of providing service, which we identified in D.96-12-077 as their authorized revenue requirements. D.97-08-056 clarified the calculation of the competition transition charge (the rate associated with headroom) as equal to the difference between each utility's frozen rate and the combination of all other costs, i.e., the PX price, the distribution rate, the transmission rate, the public purpose program surcharge and the nuclear decommissioning surcharge. PacifiCorp and Sierra must track both the revenues accruing from the calculation and collection of the transition charge and from market valuation when that valuation occurs.

We agree with ORA that headroom must be determined using the PX market-clearing price or other acceptable proxy for each utility's cost of generation. Section 367(c) provides explicitly that going forward costs must be recovered from either the PX or the ISO, with certain exceptions that are not applicable to PacifiCorp or Sierra. We have defined going-forward costs as all costs necessary for the continued or future operation of the plant or unit. (D.97-08-056, mimeo. at p. 22-23; Proposed Decision in Phase 2 of Application (A.) 96-08-001 et al., mimeo. at p. 27.) No statutory exceptions are provided for PacifiCorp and Sierra Pacific on the relevant market mechanism for recovery of going-forward costs.

As we discussed in the Phase 2 transition cost proposed decision, AB 1890 reflects several fundamental concepts articulated in the Preferred Policy Decision. For example, § 367 outlines the various categories of costs which may be eligible for transition cost recovery and reflects many of the findings of the Preferred Policy Decision in terms of transition costs. Uneconomic costs result from the difference between the net book value and the market value of a utility's generation-related assets. Uneconomic costs may also result from honoring contractual obligations. We determined that the uneconomic costs of QF and power purchase contracts would be calculated by comparing the contract price with the PX market-clearing price. (Preferred Policy Decision, mimeo. at p. 130.) The question before us now is whether the PX market-clearing price is a valid comparison point for PacifiCorp and for Sierra.

PacifiCorp proposes to use the COB electric price index, as published in the Wall Street Journal, as the basis for its market price credit during the transition period. By extension, we understand that PacifiCorp would use the COB index to establish the market-clearing price. As PacifiCorp and ORA describe it in their stipulation, this index provides on- and off-peak pricing indexes and also provides a firm and non-firm breakdown. Since firm service is being provided, PacifiCorp would base its market credit on the available firm service index. The daily on-peak price indexes would be averaged over the billing period and applied to on-peak hour consumption. The daily off-peak price indexes would be averaged over the billing period and applied to off-peak consumption. The results would be added together to calculate the billing credit. For customers without time-of-use metering, PacifiCorp would use customer class load profiles to develop a weighted average market energy price.

PacifiCorp and ORA argue that the COB index is appropriate for pricing service in PacifiCorp's northern California service territory because loads in that area can receive capacity and energy from this region, which is within the contemplated IndeGO system, without incurring further transmission wheeling charges. They argue that since the PX is located outside of the IndeGO system, its prices will not reflect the additional transmission costs that would be incurred to reach the IndeGO system.

No party has voiced an objection to this proposal. Because of the unique nature of PacifiCorp's transmission system and because PacifiCorp and its customers appear less likely to rely heavily on the PX to acquire energy, it is appropriate to use an index that relates more directly to their sphere of influence. The COB index appears to fit this description. We will allow PacifiCorp to use this index as it enters the transition period. Sierra, which has a service territory straddling the California-Nevada border, is proposing to use the PX prices as its market benchmark. While its transmission system also bears unique characteristics, Sierra has not offered a preferred alternative. We will use the PX as the market benchmark for Sierra under the conditions adopted by D.97-11-026.

3. *Eligibility*

We must now determine which generation-related assets are eligible for transition cost recovery, consistent with § 367. Exhibit 6, Appendix A presents PacifiCorp's ownership interests in generating plant. PacifiCorp owns 65 megawatts (MW) of California hydroelectric generation and 1,013 MW of non-California hydroelectric generation. PacifiCorp also owns 7,334 MW of thermal generation, the majority of which is coal-fired and is not located in California. Of this total, 26.1 MW represents the nameplate rating of a geothermal facility. Total generation capacity equals 8,412.4 MW; total non-California generation is 8,347.4. The percentage of California-located generation equals approximately 0.8% of total generation. As of January 1, 1998, approximately 2% of PacifiCorp's total rate base is allocated to California, according to Exhibit 7, Appendix B-1.

The California-allocated share of Sierra's estimated net book value of all generation-related assets and obligations equals $19 million, which includes production plant, allocated common and intangible plant, and working capital, and accounts for accumulated deferred income taxes.

For PG&E, SDG&E, and Edison, we anticipated that hydroelectric and geothermal assets are likely to be economic, even in the new competitive era. (Preferred Policy Decision, mimeo. at p. 135. We do not know whether these assets will be uneconomic for multi-jurisdictional states. The uneconomic portion of all generation assets should be allocated to California and should receive transition cost recovery. We direct PacifiCorp and Sierra to include workpapers supporting the allocation of generation assets to California in the advice letter establishing its transition cost balancing account tariffs. The generation allocated to California will be subject to market valuation for purposes of § 367(b) because hydroelectric and geothermal assets may prove to be economic, their depreciation should not be accelerated using transition cost revenues. Consistent with the requirements of § 367(b), which provides that the determination of uneconomic costs be based on a calculation mechanism that nets the value of above-market utility-owned generation assets and below-market utility-owned generation assets, hydroelectric and geothermal assets must also be market valued by year-end 2001. To the extent these assets are above book value, as we expect, these positive values will be credited to the transition cost balancing account to offset transition costs. This approach is consistent with ensuring that transition costs recovery is completed as expeditiously as possible (§ 330(t).)

As a first step in transition cost recovery, consistent with D.97-06-060, PacifiCorp and Sierra must amortize the net book value of the eligible generation assets allocated to California over the 48-month transition period. These generation-related assets should be written down to the estimated market value, but not below. In return for the reduced risk associated with transition cost recovery, we determined that it was appropriate to reduce the cost of capital for generation assets eligible for transition cost recovery by setting the return on the percentage of the undepreciated asset financed by equity at 10% below the long-term cost of debt. As we have explained in several of our decisions, AB 1890 confirms the reduced return on equity adopted in the Preferred Policy Decision. (§ 367(d).) The same principles apply to PacifiCorp and Sierra.

PacifiCorp and Sierra should base the accelerated amortization on net book value as of December 31, 1995. Section 367 adds specific requirements for transition cost recovery of capital additions made after December 20, 1995: these costs are allowed (to the extent they are uneconomic) "for capital additions to generating facilities existing as of December 20, 1995, that the commission determines are reasonable and should be recovered, provided that these additions are necessary to maintain the facilities through December 31, 2001." PacifiCorp and Sierra should file separate applications should they seek recovery of capital additions made after this cut-off date.

PacifiCorp also claims uneconomic costs of above-market QF and power purchase contracts. We do not need to forecast the amount of transition costs resulting from these above-market contractual obligations. Consistent with § 367, these costs may be recovered as incurred for the duration of the contract period. PacifiCorp and Sierra should include sub-accounts to track QF and power purchase contract costs and corresponding market recovery. For PacifiCorp, market recovery should be based on comparison with the Dow Jones COB electricity index, as published in the Wall Street Journal. For Sierra, it should be based on the Power Exchange prices.

Section 376 provides that:

> "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-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 any of these programs."

It is important to understand that these implementation costs are not included in the statutory descriptions of transition costs. For PacifiCorp and Sierra, if the costs of programs to implement direct access implementation costs are incurred and authorized for recovery and if recover of these costs results in the utility not recovering its full transition costs (as defined in §§ 367, 840(f), and 375) before the statutory deadline, then an extension of the period for collecting transition costs is granted. We will not know with any certainty to what extent authorized implementation costs displace defined transition cost recovery until the end of the transition period.

In the Phase 2 transition cost proposed decision in A.96-08-001 *et al.*, we carefully discussed various categories of costs for which PG&E, Edison, and SDG&E sought transition cost recovery. Consistent with § 367(c), we determined that it is necessary to draw a "bright line" between possible transition cost recovery as of December 31, 1997 and what should be recovered as a going-forward cost in the marketplace as of January 1, 1998. For example, we have called for market valuation of materials and supplies inventories and gas and coal inventories as of December 31, 1997, or as close to that date as possible, in order to apply these principles consistently. We do not have the information available to make such determinations in this case. We direct PacifiCorp and Sierra to file additional information so that we can determine whether each utility is seeking transition cost recovery for such items as materials and supplies inventories, fuel inventories, Construction Work in Progress, etc. In addition, we need more information to determine whether PacifiCorp is still seeking transition cost recovery of regulatory assets and how the costs of those regulatory assets are estimated.

E. Functionalized Class Revenue Requirements and Prices

In D.97-08-056, we established principles to apply to the establishment of functionalized rates and class revenue requirements. Those principles should apply to all utilities, in the absence of specific exceptions. One exception appears necessary for PacifiCorp and Sierra. For the other utilities, we determined that transmission revenues would be allocated by using transmission marginal cost responsibility and distribution revenues would be allocated by first allocating combined transmission and distribution revenue requirements in proportion to the sum of transmission and distribution marginal costs (including customer marginal costs) and then subtracting the allocated transmission revenues.

For PG&E, SDG&E, and Edison, transmission and distribution revenues are relatively close to their marginal cost revenues while generation revenue requirements are significantly in excess of marginal cost revenues. For PacifiCorp and Sierra, however, distribution and generation revenue requirements differ significantly from their related marginal cost revenues. For these companies, it is more appropriate to first allocate generation revenues in proportion to their marginal cost revenues and then assign distribution revenue requirements residually after determining the allocation for all other functions. Until it undergoes a general rate case to more precisely define its revenue requirement, it is acceptable for Kirkwood to use the simplified approach proposed by its witness for unbundling rates. With these exceptions, we will require the applicants to follow the principles set forth in D.97-08-056 as well as any formally adopted modifications to those principles that are not company-specific. Functionalized revenue requirements by class for PacifiCorp are included in Appendix B. Those for Sierra are included in Appendix C.

Applicability of the 10% Rate Reduction

A. Requirements

As we have noted, § 367 requires the Commission to "identify and determine those costs and categories of costs for generation-related assets and obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts, including, but not limited to, restructurings, renegotiations or terminations thereof approved by the commission, that were being collected in commission-approved rates on December 20, 1995, and that may become uneconomic as a result of a competitive generation market, in that these costs may not be recoverable in market prices in a competitive market, and appropriate costs incurred after December 20, 1995, for capital additions to generating facilities existing as of December 20, 1995, that the commission determines are reasonable and should be recovered, provided that these additions are necessary to maintain the facilities through December 31, 2001." It also states that these uneconomic costs shall be recovered from all customers on a non-bypassable basis.

Section 368 requires each utility to propose a "cost recovery plan" for the recovery of the uneconomic costs identified by the Commission in compliance with

§ 367. The statute goes on to require that the cost recovery plan contain these elements, among others:

1. The cost recovery plan "shall" provide for the identification and separation of individual rate components such as charges for energy, transmission, distribution, public benefit programs, and recovery of uneconomic costs. The separation of rate components "shall" be used to ensure that customers of the electrical corporation who become eligible to purchase electricity from suppliers other than the electrical corporation pay the same unbundled component charges, other than energy, that a bundled service customer pays (§ 368(b)).

2. The cost recover plan "shall" freeze rates for each customer class, rate schedule, contract, or tariff option, at levels in effect on June 10, 1996, provided that rates for residential and small commercial customers "shall" be reduced so that these customers will receive rate reductions of no less than 10% for 1998 continuing through 2002. These rate levels for each customer class, rate schedule, contract, or tariff option must remain in effect until the earlier of March 31, 2002, or the date on which the commission-authorized costs for utility generation-related assets and obligations have been fully recovered (§ 368(a)).

These requirements are clear and unambiguous. The Legislature demonstrated its intention that the cost recovery plan requirements apply to all electrical corporations by creating explicit exceptions where it deemed them to be appropriate. There are no explicit exceptions that appear to apply to any of the small or multi-jurisdictional electrical corporations.

B. Kirkwood and Bear Valley

Neither Kirkwood nor Bear Valley is seeking to recover transition costs. Kirkwood owns and operates several diesel generators with a cumulative capacity of 4.2 MW serving the seasonal load of a ski area. Because of its physical isolation and high elevation, there are no transmission lines connecting Kirkwood to the larger grid. Although Kirkwood would welcome competitive energy providers, there is no apparent means for delivering power to the service area. We find that because there is no meaningful competition, there is no relevant "market price" against which to measure Kirkwood's cost of generation to determine uneconomic costs. Kirkwood's customers do not have an immediate prospect for alternative providers and the utility must plan for continuing to provide all of the area's energy needs. The utility does not foresee a transition to competition and, therefore, does not expect to experience transition costs. However, Kirkwood does plan to unbundle its rates and would welcome any direct access providers. Bear Valley also serves a seasonal customer base. The utility will offer direct access tariffs, but it does not own any transmission or generating resources and does not have any potential transition costs.

The rate freeze and the 10% rate reduction for residential and small commercial customers required under § 368 need remain in effect only until the end of the transition period. Since neither Kirkwood nor Bear Valley has identified costs to be recovered, neither company will have a transition period. Thus, § 368 does not require a rate freeze or 10% rate reduction for Kirkwood or Bear Valley. Later, we will consider other implications of the lack of a transition period for these two companies.

C. PacifiCorp and Sierra

PacifiCorp and Sierra provide a different set of challenges. Each is a large, multi-state utility with substantial generation and transmission resources. Each agrees that the transition to competition for generation services will leave it with uneconomic costs. Each hopes to recover some of those uneconomic costs during the transition period by providing direct access customers with a market-based energy credit instead of unbundling its embedded generation costs. To the extent that average market prices are less than the generation component of the utility's rates, the utility would collect extra revenues that could serve to offset uneconomic costs. PacifiCorp acknowledges that under its preferred approach, it would be collecting transition costs. Sierra declines to use the words "transition costs" but acknowledges that it hopes to recover some uneconomic costs in this way.

Nonetheless, each argues that it is not obligated under § 368 to institute a 10% rate reduction. First, PacifiCorp argues that in its cost recovery plan, an electrical corporation seeking transition cost recovery is not required to comply with specific provisions in § 368. Under this argument, the Commission could approve any plan it finds reasonable, even if it is inconsistent with § 368. PacifiCorp suggests that the only significance of the specific provisions of § 368 is that the Commission is compelled to approve a plan if it does comply with them. As we stated in D.96-12-077 (at mimeo. p. 2), approving cost recovery plans for PG&E, SDG&E, and Edison, we agree that we are compelled to approve a plan that meets the conditions of the statute. However, we do not find in the language of the statute the freedom to approve plans that fail to satisfy its provisions. We acknowledged in D.96-12-077 that our review of cost recovery plans is not merely a ministerial act of checking compliance with the statute, since it provides only the broad framework within which the utilities must implement their cost recovery plans. However, PacifiCorp and Sierra are seeking approval of programs that are inconsistent with the broad framework set forth in the statute. Section 368 states that the utilities seeking the recovery of uneconomic costs must file a cost recovery plan, that plan must freeze rates at the June 10, 1996 level, the plan must reduce rates from the level for residential and small business customers by 10% and it must provide for appropriately unbundled charges. In D.96-12-077, we established the principle that to the extent any element of a cost recovery plan is inconsistent with § 368 or any other provision of AB 1890, the language of the statute prevails. We cannot find in the wording of § 368 the freedom to approve plans that violate these explicit requirements.

Sierra acknowledges that its proposal does not explicitly comply with § 368. In its Post-Hearing Brief, the company reflects on the "remarkable dispatch" with which the Legislature drafted and passed AB 1890 and states:

> "Sierra, unfortunately, did not a have a registered lobbyist in Sacramento in the summer of 1996 to guard its interests. Considering its low rates, its good relations with the Commission and the fact that previous restructuring proposals had not been directed toward it, the company had no reason to believe legislation would be enacted that could harm it economically or operationally. AB 1890 thus passed before Sierra was able to analyze the bill and determine the

> extent to which the bill could harm the company if strictly applied...Sierra's intent in submitting a plan that does not identify uneconomic costs as [transition costs] was not to evade AB 1890 but rather to comply directly with as much of it as possible without damaging the company economically or operationally...."

We do not have the discretion in implementing AB 1890 to grant Sierra the exceptions it seeks. Section 368 requires compliance by "each electrical corporation." In subportions of § 368, the Legislature creates specific exceptions, none of which appear to apply to PacifiCorp or Sierra. Subsection (c) allows utilities or certain size and make-up to employ risk management tools to protect against the volatility of natural gas market prices. Subsection (d) allows greater flexibility for the recovery of nuclear costs. Subsection (e) allows utilities of certain size and make-up to receive annual base revenue increases in 1997 and 1998. As we observed in our decision approving unbundled rates for PG&E, SDG&E, and Edison, the rules of statutory construction provide that "where exceptions to the general rule are specified by statute, other exceptions are not to be implied or presumed." (See D.97-08-056 at mimeo. p. 31). Thus, we are not able to take into account the special circumstances faced by Sierra and PacifiCorp nor to conclude that although they seek to recover uneconomic costs of generation, they need not comply with the requirements of § 368.

D. Edison's Views

Expressing a general interest in the interpretation of these provisions, Edison has filed briefs offering its view of PacifiCorp and Sierra's obligation to offer a 10% rate reduction to residential and small commercial customers. First, Edison argues that § 367, which establishes the utilities' right to recover transition costs, does not indicate that this right is contingent upon a reduction in rates for residential and small commercial customers. Without responding to Edison's assertions about the nature of the utilities' right to recover transition costs, we note that Edison ignores the fact that § 368 does create such a contingency. It states that a utility seeking recovery of uneconomic costs as described in § 367 must file a cost recovery plan, which must include a 10% rate reduction. Edison would suggest that these requirements do not matter, because the Commission can let the utilities collect transition costs anyway. If this is true, then why did the Legislature include § 368 at all? If it was only to provide a set of conditions under which the Commission could not avoid approving transition cost recovery, then why was this avenue not simply provided to the utilities as an option? Why were the utilities required to file these plans? For the Legislature to require utilities to file plans which they need not have, or to require that the plans include provisions that are not necessary to gain approval would have made the statute meaningless. We cannot accept such an interpretation when the plain language of the statute suggests otherwise.

Edison goes on to argue that a utility cannot be required to reduce its rates by 10% if it has not issued rate reduction bonds. We previously rejected this argument in D.96-12-077 (see mimeo. p. 9) where we approved cost recovery plans for Edison and others, and stated both that § 368 (a) "requires the utilities' plans to include a rate reduction of at least 10% for small commercial and residential customers" and that "AB 1890 allows the utilities the option of accomplishing the required rate reduction by issuing rate reduction bonds, as described in §§ 840-847." Edison sought modification of this language in a subsequent petition and continues to argue its position, here. We need not revisit this issue, here, because PacifiCorp and Sierra have not applied for rate reduction bonds, as required under § 841(a). No matter what the merits of Edison's argument might be, the lack of rate reduction bonds cannot be raised as a protection against the required 10% rate reduction when the utilities have not sought authority to issue the bonds. To hold otherwise would be to make the 10% rate reduction requirement meaningless: a utility could avoid the reduction simply by declining to ask for permission to issue the bonds.

Edison argues that it might be impossible for the smaller utilities to issue such bonds at all, and certainly impossible to issue them by January 1, 1998. Thus, Edison suggests that the statute must be interpreted not to require the 10% rate reduction, since the statute must not be interpreted to require a legal impossibility. First, it is not clear if Edison is suggesting that either PacifiCorp or Sierra is a smaller utility. Regardless, its suggestion that it might be impossible for such a utility to sell bonds is conjecture. Since the utilities have not attempted to obtain rate reduction bonds, by January 1, 1998, or any other time, there is no basis for reaching such a conclusion. More to the point, it is not impossible for the utilities to reduce their residential and small commercial customers' rates by 10%.

E. Conclusions Concerning the 10% Rate Reduction

For all of these reasons, we find that if a utility offers plans to recover uneconomic costs of generation, all of the provisions of § 368 apply, including the 10% rate reduction for residential and small commercial customers. The purpose for the cost recovery plan under § 368 is the recovery of the uneconomic costs of an electrical corporation's generation-related assets and obligations identified in § 367. Where there are no such costs, there is no requirement to file a cost recovery plan. However, we elect to apply the rate unbundling framework of § 368(b) to Kirkwood and Bear Valley even though neither is seeking transition cost recovery. Section 365 (b) (1) states that the Commission must authorize direct transactions between electricity suppliers and end use customers. That requirement applies to the Commission's treatment of all electrical corporations. As the Commission stated in its Preferred Policy Decision, the unbundling of utility revenues and rates is fundamental to the competitive offering of electric services. Section 368 (b) provides the broad framework for rate unbundling that will apply to the rates for all other customers of regulated utilities in the state. No reason has been offered for applying a lesser standard to Kirkwood and Bear Valley.

As mentioned earlier, PacifiCorp is currently subject to a PBR mechanism. Under this mechanism, in the absence of the rate freeze, PacifiCorp would anticipate raising its rates in 1997 and 1998. PacifiCorp and ORA recommend that when calculating the 10% rate reduction, the company be allowed to give itself credit for the forgone rate increases. Similarly, Sierra points out that it reduced its rates on June 1, 1996, which is only nine days before the "rate freeze" date in AB 1890. Sierra asks that it be given credit for its earlier rate change when calculating the 10% reduction. The result of either proposal would be a rate reduction of less than 10% from the rates in effect on June 10, 1996. Such a result would be an explicit violation of the statute, which provides for no applicable exceptions. Thus, we cannot adopt these requested modifications.

Sierra proposed to use a balancing account to record the revenues lost due to the 10% rate reduction, accruing interest at the company's weighted cost of capital. The company would recover the accrued balance over six years, beginning at the end of the transition period. ORA appears to support this proposal, but suggests that the interest rate correspond to the rate of commercial paper.

The provisions of AB 1890 state that, with limited exceptions, transition costs can be recovered only during the transition period. An exception is the recovery of remaining fixed transition amounts as defined in § 840(d). Cost stemming from rate recovery bonds (as defined in § 840(e)), which PG&E, SDG&E, and Edison have been permitted to issue, are an example of fixed transition amounts. As we explained in D.97-09-054, for fixed transition amounts to be recoverable, we must so designate them in a financing order (as defined in § 840(c)) if we determine, as part of our findings in connection with the financing order, that the designation of the fixed transition amounts would reduce rates that residential and small commercial customers 2 would have paid if the financing order were not adopted.

If Sierra or PacifiCorp were to seek post-transition period balancing account recovery for revenues forgone by the 10% rate reduction, they would be deferring the recovery of transition costs until after the transition period. Neither company has cited an exemption in AB 1890 that would allow for such recovery. In addition, Sierra's proposal has two features which may increase the burden on residential and small commercial ratepayers of the recovery of these costs. First, the company would have taken no steps to reduce the financing costs. Second, since the company would not begin to recover the costs until after the transition period, ratepayers would face higher costs in the period immediately thereafter. The fixed transition amounts that we approved for other utilities will be amortized over ten years, including the transition period, during which a portion of the otherwise-available headroom revenues will be devoted to this purpose.

Sierra and PacifiCorp initially chose not to pursue rate reduction bonds, or any other financing mechanism. If either company wishes to recover the cost of the 10% rate reduction, it may file a financing order pursuant to § 841 seeking authority to established fixed transition amounts for this purpose. In so doing, the company must demonstrate that its proposed financing method will lead to a reasonable cost of debt, in light of the success other utilities have experienced in placing rate reduction bonds. In order to enable the utilities to seek effective recovery of its rate reduction costs, we will permit each company to track its forgone revenues in a memorandum account. If this commission approves the establishment of fixed transition amounts for these purposes, we will apply an amortization period similar to those adopted for PG&E, SDG&E, and Edison, presumed to begin with the onset of the transition period. Thus, to maximize its opportunity for recovery, we encourage the companies to file any such request as soon as possible.

PacifiCorp's initial transition plan proposal included no 10% rate reduction. In its opening brief, PacifiCorp stated that if the Commission were to nonetheless require a 10% reduction, it would withdraw its initial proposal and seek to continue receiving annual rate increases under its PBR mechanism. This proposal also is inconsistent with the law. First, PacifiCorp has established that it faces uneconomic generation costs, at least some of which it would hope to recover under frozen rates. As we discussed above, PacifiCorp is obligated to track and account for those costs and to cease collecting transition charges when it has recovered all of its uneconomic costs. It is transparent that if we were to allow PacifiCorp to raise its rates, instead of freezing them, it would recover even more of its uneconomic costs without accountability and without instituting the rate freeze or the required rate reduction for residential and small commercial customers.

If, on the other hand, we were to interpret PacifiCorp's alternative proposal as one under which the company would recover no uneconomic costs, then the company would not have a transition period. It would need to immediately remove all embedded generation costs from its base revenues and could only charge its full-service customers the market rate for energy. In a matter of weeks, this would require either eliminating the company's current PBR mechanism and determining an appropriate revenue requirement, or establishing a new distribution-only PBR. In either event, rather than result in a rate increase, the process would be likely to result in a rate reduction. For all of these reasons, it would not be reasonable to adopt PacifiCorp's alternative proposal.

While we find that the clear prescriptions of AB 1890 lead us to these conclusions, we recognize that PacifiCorp and Sierra offer rates that much more closely approximate the national average than do those offered by PG&E, SDG&E, and Edison. We also recognize that none of the current applicants may have been part of the dialogue at the Legislature that led to the provisions in AB 1890 and that the bill is devoid of specific references to these companies. It is not hard to imagine that one or both of these companies may choose to approach the Legislature, in response to this decision, in search of explicit exemptions from the otherwise-required rate reduction. If the Legislature chooses to act on this issue, we encourage PacifiCorp and Sierra to work to ensure that we receive clear instructions from the Legislature as to how we should implement any change from the 10% rate reductions that we order today.

On December 3, 1997, in its comments to the Proposed Decision, PacifiCorp expressed a willingness to forego recovery of all transition costs other than the above-market cost of QF contracts, in order to avoid offering a 10% rate reduction to its residential and small commercial customers. PacifiCorp also says that, in such circumstances, it would prefer to forego most transition cost recovery "in order to avoid extensive, burdensome stranded cost and valuation proceedings, and maintenance of numerous balancing accounts in a retail jurisdiction representing less than 2% of PacifiCorp's retail business." Under this proposal, there would be no transition period and PacifiCorp would immediately go "to market" by filing unbundled delivery rates effective for the first full billing cycle after January 1, 1998. The company would offer generation at market-based prices and asks to add a non-bypassable charge to recover the above market cost of QF contracts (estimated by the company to total approximately $8 million over the next 18 years).

The company offered this proposal for the first time only 13 days before the date of this decision. We have not had the benefit of careful scrutiny or studied reaction from other parties. ORA appears to express general support for this proposal, although it objects to the recovery of ongoing uneconomic QF costs in such circumstances. No other party have offered its reactions.

There is an initial appeal to this proposal, because it suggests a mechanism for PacifiCorp (and perhaps Sierra) to simplify the regulatory process and move toward a more competitive environment immediately. PacifiCorp also would avoid providing a 10% rate reduction for its residential and small commercial customers. We are sympathetic with that effort, since both PacifiCorp and Sierra have rates that are comparatively lower than those offered by PG&E, SDG&E, and Edison. However, PacifiCorp's proposal suffers from at least two significant problems.

The first problem is that the proposal was not presented and considered in the underlying proceeding where other proposals were presented, hearings were held and other parties participated. We have not been able to carefully test the merits of the proposal or the proposed market price. The second problem concerns the lack of analysis or evidence addressing the market power implications of the proposal. The impact on competition of the policies of the Commission is one of the necessary elements to be considered in granting such authority. Section 330(l) endorses this commission's conclusions that generation of electricity should be open to competition, there should be a transition from regulated to unregulated status through the use of commission-approved market valuation mechanisms and that there is a need to ensure that no participant in these new market institutions has the ability to exercise significant market power that could result in distortions in the operation of the new market institutions.

PacifiCorp's proposal is to allow market-based rates for generation to its customers. Presumably, PacifiCorp would also wish to sell its generation at market-based prices. For the three large electric utilities, these concepts go together due to the PX buy/sell requirement. However, no such requirement is in place for PacifiCorp and market power concerns arise for PacifiCorp in connection with sale of generation that are mitigated for larger utilities. It might have been possible to consider PacifiCorp's proposal in this proceeding if an accompanying plan was proposed to address treatment of PacifiCorp's generation assets, but there is no record on this topic. We cannot adopt a partial plan at this time without consideration of an intrinsically linked issue.

The Legislature set forth the requirements of market valuation in § 377, which states that should the utility choose to retain a generation asset following market valuation, it must show that it is in the public interest to do so, in a forum allowing for hearing and a showing that to retain the asset would not confer undue competitive advantage on the public utility. PacifiCorp seeks to retain control of its public utility generating assets without submitting to the inquiry dictated by § 377. To approve PacifiCorp's proposal in this context would be to ignore our obligation to ensure that the prices it offers to its customers reflect those of the appropriate competitive market and that the market mechanism does not confer undue competitive advantage on the utility.

There are at least two ways that PacifiCorp or Sierra could offer its customers market-based rates and be consistent with § 377. One would involve applying to the FERC for market-based rate authority through the Power Exchange by agreeing to a buy/sell requirement and market power mitigation measures such as a rate freeze, CTC collection and rate reduction. This would address any existing market power concerns in a manner consistent with other California investor-owned utilities prior to completion of market valuation and our issuance of the findings required under § 377. A second approach would involve accelerating the completion of market valuation and the processes required under § 377. In addition, we will give serious consideration to any innovative proposal that is consistent with applicable statutes.

PacifiCorp and Sierra retain the option of pursuing one of these avenues. We encourage PacifiCorp and/or Sierra to make the appropriate filings here and/or at FERC. However, this does not obviate the need to institute the rate freeze and other requirements of § 368 on January 1, 1998. Those requirements continue to apply throughout the transition period. A decision by a utility to buy from and sell to the Power Exchange would not, in itself, shorten the transition period. If a utility chose to pursue an accelerated review of its assets under § 377 and was willing to forego further transition cost recovery, it might be able to shorten the transition period, after which it would not be subject to the rate freeze or the 10% rate reduction.

In offering to forego transition cost recovery, PacifiCorp expressed the hope of avoiding the need to perform a market evaluation of its generating assets. We want to make it clear that AB 1890 does not provide that opportunity. Section 216(h) states:

> "Generation assets owned by any public utility prior to January 1, 1997, and subject to rate regulation by the commission, shall continue to be subject to regulation by the commission until those assets have undergone market valuation in accordance with procedures established by the commission."

This requirement is repeated in § 377, which states:

> "The commission shall continue to regulate the nonnuclear generation assets owned by any public utility prior to January 1, 1997, that are subject to commission regulation until those assets have been subject to market valuation in accordance with procedures established by the commission. If, after market valuation, the public utility wishes to retain ownership of nonnuclear generation assets in the same corporation as the distribution utility, the public utility shall demonstrate to the satisfaction of the commission, through a public hearing, that it would be consistent with the public interest and would not confer undue competitive advantage on the public utility to retain that ownership in the same corporation as the distribution utility.

These requirements do not affect Kirkwood, which cannot provide meaningful direct access and will continue to subject its generating assets to the commission's jurisdiction. Nor do they affect Bear Valley, which has no generating assets. However, a critical feature of our restructuring effort as it concerns PacifiCorp and Sierra is the introduction of market-place forces to govern their decisions about how to meet the energy needs of their full-service customers. In order to do this, each company must remove all energy-related costs and generating assets from its California revenue requirements and its underlying rate base, effectively ending our regulation of these assets. Pursuant to §§ 216(h) and 377, a decision to cease regulating these assets must be actively reached and can made only after the completion of market valuation.

Although PacifiCorp and Sierra may file a § 377 application sooner, we will direct the utilities to complete the market valuation before the end of 2001.

The Stipulation Between PacifiCorp and ORA

On October 8, 1997, while hearings were in progress, PacifiCorp and ORA offered a stipulation which appears as an appendix to this order. This stipulation reflects areas of agreement between the two parties, but was not presented as a settlement pursuant to our rules of practice and procedure. No other party has endorsed the stipulation in its entirety and some parties disagreed with many of its provisions. We have addressed the merits of the terms of the stipulation throughout this opinion. Here, we will offer a summary of the status of the various proposals contained in the stipulation.

1. Implementation of Direct Access

This provision is consistent with our finding that PacifiCorp, as well as all other applicants, must provide direct access to all customers on January 1, 1998.

2. Bill Unbundling

This portion of the stipulation accurately describes what PacifiCorp is expected to do on January 1, 1998, but does not reflect the requirement that PacifiCorp fully unbundle its rates by June 1, 1998, as discussed earlier.

3. Consumer Education Plan

This language accurately reflects that PacifiCorp's Consumer Education Plan was approved in D.97-08-063.

4. Public Purpose Programs

The language in this section of the stipulation is consistent with this decision.

5. Reliability and Safety

As is reflected in this section, PacifiCorp and the other applicants are expected to participate in and comply with our proceedings relating to reliability and safety.

6. Independent System Operator and Power Exchange

We have approved the proposal that PacifiCorp participate in IndeGO provided that the ISO agrees. Under this decision, the ISO retains the final word as to how the PacifiCorp and Sierra transmission systems are controlled.

7. Cost Recovery of Ongoing Obligations and Direct Access Implementation

This section accurately describes the approach we are adopting for PacifiCorp in this decision.

8. Performance-Based Ratemaking

As discussed earlier, we are unable to approve PacifiCorp's request to provide a credit for forgone PBR-derived rate increases when calculating the 10% rate reduction required under § 368. In other respects, this section is acceptable.

9. Rate Freeze

PacifiCorp is required to freeze its rates until the end of the transition period or December 31, 2001, whichever comes sooner. However, it must also institute the 10% rate reduction for residential and small commercial customers discussed earlier.

10. Rate Reduction Bonds

This section appears to accurately reflect PacifiCorp's intention not to seek Rate Reduction Bonds.

11. Transition Cost Recovery

This section accurately reflects the COB index that we are approving in this order, but does not accurately reflect the bill unbundling, rate reduction, and transition cost recovery processes described in this order.

12. Functionalized Class Revenue Requirements and Prices

This section accurately reflects the approach adopted in this order for allocating PacifiCorp's revenues by class.

Issues About PacifiCorp's Transition Plan Raised by Richard and Ryan Schader

Richard and Ryan Schader are father and son farmers near California's northern border who are served by PacifiCorp. They have provided, for the record in this proceeding, an eloquent description of the challenges they face as competitive farmers and the importance of reasonable pumping costs in meeting those challenges. They question PacifiCorp's assertion that its rates are low when compared to those of PG&E and other California utilities by presenting an historical comparison of the rates they have paid to PacifiCorp and those paid by farmers in the region who are served by PG&E. The questions they raise about the appropriateness of PacifiCorp's rates are beyond our reach as we head into a lengthy rate freeze. The issues they raise about the efficiency of PacifiCorp's operation and appropriate revenue levels must be more thoroughly examined when we review and reconsider PacifiCorp's PBR mechanism.

As an agricultural customer, the Schaders do not stand to benefit from the 10% rate reduction for residential and small commercial customers. However, it is our fervent hope that they do stand to benefit from the availability of competitive energy providers. They have appropriately highlighted the significant impact of high charges for distribution. This is one of the challenges PacifiCorp's California customers face in more remote and rural areas. However, we will continue to seek approaches for lowering those costs through the PBR process as well as more traditional cost-based regulation. However, the onset of the transition period and the concurrent rate freeze preclude us from having a direct impact in this area in the next few years.

Conclusion

With this decision, we set the stage for the involvement of PaficiCorp, Sierra, Kirkwood, and Bear Valley in California's restructured electric market. We must now move quickly to implement the conclusions that we reach here. In D.97-10-087, we granted interim approval to the tariffs, rate schedules and service agreements proposed by PacifiCorp, Sierra, and Bear Valley, pending the outcome of this proceeding. We also directed those companies to file advice letters containing their final direct access tariffs, related rate schedules, other affected rate provisions and service agreements within 45 days from the date of this decision. Those filings must be consistent with the requirements applied to other electrical corporations in D.97-10-087, subject to any modifications resulting from this decision. We will continue to adhere to the schedule set forth in D.97-10-087, with one exception. Because the 10% rate reduction for residential and small commercial customers must take effect no later than January 1, 1998, we will direct PacifiCorp and Sierra to file revised tariffs necessary to reflect this reduction within 5 working days of the issuance of this decision. Kirkwood should also file any revised tariffs necessary to implement this decision within 45 days.

Findings of Fact

1. Bear Valley owns no electric generation facilities, and Kirkwood has no transmission facilities and is therefore not connected to the regional transmission grid.

2. Each of the applicants has pledged to provide its customers with direct access to the services of competing energy providers beginning January 1, 1998.

3. Because there are no apparent avenues to competition, it is premature to require Kirkwood to submit a detailed direct access plan.

4. PU Code §§ 368(b) and 392(b) require that all customers be informed of the portion of their charges that reflect uneconomic cost.

5. In order to understand the risks and benefits of direct access, customers must be fully informed of the charges that they stand to avoid.

6. We see no reason that competing energy providers should face different conditions concerning revenue cycle services when offering to serve the customers of these applicants than they face when seeking to serve the customers of PG&E, SDG&E, or Edison.

7. Its current contracts require Bear Valley to take all generation capacity from Edison, but do not require it to acquire ancillary services from Edison.

8. We do not interpret § 381 as requiring that we adopt a new funding level for the public purpose programs of any of the applicants.

9. It is reasonable for Bear Valley to devote 1.4% of its revenues to public purpose programs.

10. Kirkwood has fewer than 500 customers.

11. Section 382 requires that electrical corporations continue to fund programs provided to low-income electricity customers, including, but not limited to, targeted energy-efficiency services and the CARE program, at not less than 1996 authorized levels based on an assessment of customer need.

12. An allocation by Kirkwood of 1% of its revenue requirement to low-income and CARE programs would generate $2,200.

13. It is most important to preserve adequate funding for low-income and energy efficiency programs.

14. No California electrical corporation can be authorized to collect any competition transition charge unless it commits control of its transmission facilities to the ISO.

15. PacifiCorp and Sierra Pacific each owns and operates transmission facilities in California and each anticipates experiencing uneconomic generation-related costs and hopes to recover at least some of those costs through transition charges.

16. The goal of whatever control the ISO exerts should be to ensure that all customers have the opportunity to choose direct access and that all energy service

providers have comparable access to transmission and distribution facilities of regulated utilities.

17. The ISO has found that it would be impractical for it to take control over PacifiCorp's and Sierra's transmission facilities and is, instead, seeking to finalize operating agreements with these firms.

18. Kirkwood could neither buy from nor sell to the Power Exchange, since it is not connected to the transmission grid.

19. Bear Valley has no generation to sell, is committed to purchase its capacity from Edison and purchases all of its energy requirements on the open market.

20. The complexities of multi-state service and regulation suggest that it may be impractical or counter-productive to require either PacifiCorp or Sierra to sell to or buy from the Power Exchange.

21. It is consistent with §§ 367(a)(2) and 376 for PacifiCorp and Sierra to recover costs after the end of the transition period that are related to direct access implementation (under some circumstances) and uneconomic costs stemming from ongoing obligations (such as contracts for purchases from QFs under the Federal Public Utility Regulatory Policies Act).

22. Section 368 requires an electrical corporation that is seeking to receive recovery of uneconomic generation costs to file a cost recovery plan which must, among other things, set rates for each customer class, rate schedule, contract, or tariff option, at levels equal to the level as shown on electric rate schedules as of June 10, 1996.

23. Section 368 also requires that such utilities reduce rates for residential and small commercial customers by at least 10% from those levels. These rates must stay in effect until the end of the transition period.

24. Since the transition period for Kirkwood and Bear Valley ends before it begins, neither firm is required under § 368 to enter into or maintain a rate freeze.

25. Section 367 specifically requires this Commission to determine which costs may become uneconomic in the new competitive market.

26. We cannot know whether headroom for PacifiCorp or Sierra is insufficient to pay for uneconomic costs at this time.

27. There is no need to forecast total transition costs at this point, because we cannot yet acquire correct information about the market-clearing price, nor about market valuation.

28. Section 367(b) requires those assets subject to valuation to be market valued by December 31, 2001.

29. Even an appraisal of generation assets which serve California customers of PacifiCorp and Sierra would be a costly undertaking and would not necessarily add significantly to our understanding of uneconomic costs at this time.

30. Headroom must be determined using the PX market-clearing price as a proxy for each utility's cost of generation.

31. The COB index is appropriate for pricing service in PacifiCorp's northern California service territory because loads in that area can receive capacity and energy from this region, which is within the contemplated IndeGO system, without incurring further transmission wheeling charges.

32. Only the fossil generation that is allocated to California should receive transition cost recovery.

33. It is necessary to make a clear distinction between possible transition cost recovery as of December 31, 1997 and what should be recovered as a going-forward cost in the marketplace as of January 1, 1998.

34. For PacifiCorp and Sierra, it is appropriate to allocate generation revenues in proportion to their marginal cost revenues and then assign distribution revenue requirements residually after determining the allocation for all other functions.

35. Section 368 requires that PacifiCorp and Sierra provide for the identification and separation of individual rate components such as charges for energy, transmission, distribution, public benefit programs, and recovery of uneconomic costs.

36. Section 368 requires that PacifiCorp and Sierra freeze rates for each customer class, rate schedule, contract, or tariff option, at levels in effect on June 10, 1996, provided that rates for residential and small commercial customers "shall" be reduced so that these customers will receive rate reductions of no less than 10% for 1998 continuing through 2002.

37. Section 368 does not require a rate freeze or 10% rate reduction for Kirkwood or Bear Valley.

38. If a utility offers plans to recover uneconomic costs of generation, all of the provisions of § 368 apply, including the 10% rate reduction for residential and small commercial customers.

39. Section 365 (b) (1) states that the Commission must authorize direct transactions between electricity suppliers and end use customers. That requirement applies to the Commission's treatment of all electrical corporations.

40. To approve a rate reduction of less than 10% from the rates in effect for PacifiCorp and Sierra on June 10, 1996, would be an explicit violation of the statute, which provides for no applicable exceptions.

41. It would be inconsistent with the law if PacifiCorp were to receive annual rate increases under its PBR mechanism in lieu of a transition period.

42. If we were to allow PacifiCorp to raise its rates, instead of freezing them, it would recover even more of its uneconomic costs without accountability and without instituting the rate freeze or the required rate reduction for residential and small commercial customers.

Conclusions of Law

1. Because there are no apparent avenues to competition for electric generation, it is premature to require Kirkwood to submit a detailed direct access plan.

2. The transition charges must be clearly stated on all customer bills, bundled or otherwise, and the rates for all customers must be fully unbundle by function.

3. We should allow PacifiCorp and Sierra to employ their proposed market index credit approach until June 1, 1998.

4. As of June 1, 1998, bills for all of their customers must include a separate accounting for the full embedded cost of generation and competitive transition charges.

5. By February 1, 1998, PacifiCorp, Sierra, Bear Valley, and Kirkwood should be required to file proposals for unbundling and separately charging for revenue cycle services.

6. PacifiCorp, Sierra, Bear Valley, and Kirkwood must begin to accommodate third-party meters and metering services consistent with D.97-05-039 and be ready to enter into service agreements with competing firms.

7. We should direct Bear Valley to separately identify, and credit to the bills of qualifying direct access customers, its ancillary costs.

8. We should require that funds for public purpose programs continue to be collected at current levels and be submitted to the appropriate oversight boards for distribution.

9. Because of its exceedingly small customer base, we should not create a public purpose funding requirement for Kirkwood on the basis of its existing revenue requirement.

10. Consistent with § 382, we will require PacifiCorp, Sierra, and Bear Valley to maintain their current levels of funding for low-income and CARE programs.

11. Low-income and CARE funds should be submitted to the Low Income Governing Board for further disbursement.

12. We should not require Kirkwood to allocate funds to the CARE program because of the small amount of revenues that it would generate compared to any likely administrative costs and the apparently minimal number of low-income customers in its service territory.

13. We should direct PacifiCorp, Sierra, and Bear Valley to maintain the current level of funding for low-income energy efficiency and CARE programs and to allocate the remaining public purpose program funds evenly across the two remaining categories.

14. PacifiCorp and Sierra must commit control of their California transmission facilities to the ISO.

15. It is for the ISO to determine the best way to ensure that direct access customers and suppliers can gain access to each other across the transmission systems owned by PacifiCorp and Sierra.

16. PacifiCorp and Sierra should be required to modify their respective FERC transmission tariffs no later than thirty days after the ISO and transmission owners tariffs are approved by FERC if necessary.

17. We should direct PacifiCorp to file a new distribution PBR proposal no later than December 31, 1998.

18. Sierra should file a distribution PBR proposal no later than December 31, 1999.

19. While there are certainly aspects of the small and multi-jurisdictional utilities that are unique, to the extent such utilities are seeking transition cost recovery, we should apply principles and guidelines which we have previously determined to be consistent with the law and essential for the transition cost recovery of PG&E, Edison, and SDG&E.

20. We should order PacifiCorp and Sierra to establish transition cost balancing accounts which will track transition costs and transition cost recovery and are established in sufficient detail to track market valuation on a plant-specific basis.

21. We should order PacifiCorp and Sierra to report to us no later than July 1, 1998 with a proposed mechanism for establishing market values for their generation assets.

22. We should allow PacifiCorp to use the COB index as it enters the transition period.

23. We will use the Power Exchange as the market benchmark for Sierra under the conditions adopted by D.97-11-026.

24. PacifiCorp and Sierra should include workpapers supporting the allocation of all generation assets to California in the advice letters establishing their transition cost balancing account tariffs.

25. As a first step in transition cost recovery, consistent with D.97-06-060, PacifiCorp and Sierra must amortize the net book value of the eligible generation assets allocated to California during the transition period.

26. PacifiCorp and Sierra should base the accelerated amortization on the net book value of the uneconomic generation assets as of December 31, 1995.

27. PacifiCorp and Sierra should include sub-accounts to track QF and purchase power contract costs and corresponding market recovery.

28. For PacifiCorp, market recovery should be based on comparison with the Dow Jones COB electricity index, as published in the Wall Street Journal. For Sierra, it should be based on the Power Exchange prices.

29. We should direct PacifiCorp and Sierra to file additional information so that we can determine whether each utility is seeking transition cost recovery for such items as materials and supplies inventories, fuel inventories, Construction Work in Progress, etc.

30. We need more information in order to determine whether PacifiCorp is still seeking transition cost recovery of regulatory assets and how the costs of those regulatory assets are estimated.

31. We established principles to apply to the establishment of functionalized rates and class revenue requirements in D.97-08-056. The principles should apply to all utilities, in the absence of specific exceptions.

32. With one exception specified in this decision (relating to functionalized revenue allocation), we should require the applicants to follow the principles set forth in D.97-08-056 as well as any formally adopted modifications to those principles that are not company-specific.

33. The Commission should apply rate unbundling framework of § 368(b) to Kirkwood and Bear Valley even though neither is seeking transition cost recovery.

ORDER

IT IS ORDERED that:

1. As of January 1, 1998, Southern California Water Company's Bear Valley Electric (Bear Valley), Kirkwood Gas and Electric Company (Kirkwood), PacifiCorp and Sierra Pacific Power Company (Sierra) (collectively, the applicants) shall provide their electric customers with direct access to competitive energy services in a manner consistent with this order and Decision (D.) 97-10-087.

2. Because its customers have no apparent access to competitive energy services, it is not necessary for Kirkwood to submit a detailed direct access plan at this time.

3. From January 1, 1998 through no later than May 31, 1998, PacifiCorp and Sierra shall provide energy credits on the bills of direct access customers as proposed in their transition plans. No later than June 1, 1998, the applicants shall separately state on their bills, charges for energy, transmission and distribution services; where applicable, the applicants shall separately state charges for public benefit programs and uneconomic costs. Subject to qualifications set forth in this decision, the applicants shall follow the principles set forth in D.97-08-056 for the functional allocation of revenues.

4. No later than February 1, 1998, PacifiCorp, Sierra, and Bear Valley shall submit, through a new application, proposals for implementing the three billing options set forth in D.97-05-039 and for separating costs for revenue cycle services as set forth in that order.

5. As of January 1, 1998, PacifiCorp, Sierra, and Bear Valley must begin to accommodate third-party meters and metering services in a manner consistent with D.97-05-039 and be ready to enter into service agreements with competing firms.

6. Bear Valley shall include, in its credit on the bills for qualifying direct access customers, a credit for ancillary costs, which include system protection services, line losses and energy imbalance services.

7. Public purpose programs shall be funded by the applicants at the levels indicated in this decision the funds shall be submitted to the appropriate oversight boards for distribution. Within 30 days of this decision, applicants shall file in this proceeding and submit to the Energy Division, a tabular report with corresponding citations of authority for each of the amounts that make up the current public purpose program funding levels. The report shall include the following major categories: (1) Energy Efficiency Programs, (2) Low Income Energy Efficiency Programs, (3) CARE, (4) RD&D, and (5) Renewables. Applicants shall also include meaningful subcategories as appropriate, including authorized administration costs. These reports shall be forwarded to the oversight boards as well.

8. Kirkwood shall not be required to set aside funds for public purpose programs on the basis of its current revenue requirement. However, Kirkwood shall file a new

general rate case application no later than December 31, 1998 which shall include a proposal for an appropriate level of public purpose program funding.

9. PacifiCorp and Sierra shall submit control of their California transmission systems to the Independent System Operator (ISO). The ISO will determine the appropriate level of control to ensure that direct access customers and suppliers can gain access to each other across the companies' respective transmission systems.

10. PacifiCorp shall file a new distribution Performance-Based Ratemaking (PBR) proposal no later than December 31, 1998.

11. Sierra shall file a distribution PBR proposal no later than December 31, 1999.

12. PacifiCorp and Sierra shall each freeze its rates for each customer class, rate schedule, contract or tariff option as shown in its electric rate schedules as of June 10, 1996. However, effective January 1, 1998, each shall reduce its rates in effect as of that date for residential and small commercial customers by 10%.

13. In that neither utility is seeking the recovery of uneconomic generation costs, neither Kirkwood nor Bear Valley is required to freeze its rates or to institute a 10% rate reduction.

14. Within 45 days of the date of this decision, PacifiCorp, Sierra, and Bear Valley shall file advice letters with revised tariffs implementing this and other Commission decisions as required in D.97-10-087. However, PacifiCorp and Sierra shall file revised tariffs necessary to reflect the 10% rate reduction for residential and small commercial customers within 5 working days of the issuance of this decision. The protest period for the latter filings is hereby shortened to 10 days.

15. PacifiCorp and Sierra shall apply principles and guidelines which we have previously determined to be consistent with the law and essential for the transition cost recovery of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company.

16. Within 5 working days of the date of this decision, PacifiCorp and Sierra shall file advice letters establishing transition cost balancing accounts which will track transition costs and transition cost recovery and are established in sufficient detail to

track market valuation on a plant-specific basis. The protest period for these advice letters is hereby shortened to 10 days.

17. No later than July 1, 1998, PacifiCorp and Sierra shall file applications proposing a mechanism for establishing market values for their generation assets. The application should include information that will enable the Commission to determine whether either utility is seeking transition cost recovery for such items as materials and supplies inventories, fuel inventories and Construction Work in Progress. In addition, PacifiCorp shall provide sufficient information to enable the Commission to determine whether the company is seeking transition cost recovery of regulatory assets and how the costs of these assets are estimated.

18. PacifiCorp and Sierra shall use monthly average power exchange prices as the basis for its market price credit and as a benchmark to assess market recovery of generation costs.

19. In all other respects, the applications are approved.

20. These proceedings are closed.

This order is effective today.

Dated December 16, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners

We will file a partial dissent.

/s/ JESSIE J. KNIGHT, JR.
Commissioner

/s/ JOSIAH L. NEEPER
Commissioner

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(END OF APPENDIX A)

In the Matter of the Application for)
Approval of PacifiCorp's (U 901-E))
Transition Plan) A.97-05-011

STIPULATION AGREEMENT
BETWEEN PACIFICORP AND
OFFICE OF RATEPAYER ADVOCATES

Pursuant to the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Section 51.3 ("Rule 51.3"), the Commission's Office of Ratepayer Advocates ("ORA") and PacifiCorp (or the "Company") (collectively, the "Parties") respectfully submit to the Commission this Stipulation Agreement. The Parties believe the Stipulation represents resolution of issues which is fair, just, reasonable and in the public interest. In addition, the Parties desire to avoid the expense, inconvenience and uncertainty attendant to protracted litigation of issues in dispute between them led to negotiation and execution of this Stipulation Agreement.

In entering into this Stipulation Agreement the Parties recognize that agreement has not been reached on the issue of the interpretation of Section 368 of AB 1890 with respect to whether PacifiCorp is required to reduce rates by ten percent for its residential and small commercial customers. PacifiCorp contends that a Section 368 rate reduction is not mandatory under the Company's preferred cost recovery plan; ORA contends that such a decrease is required. The Initial and Reply Briefs addressing this issue have been submitted by interested parties in this proceeding. The Parties propose that the Commission authorize PacifiCorp to "credit" increases justified by PacifiCorp's performance-based ratemaking ("PBR") mechanism, but foregone by the company, as part of any required rate reduction. See Section 8 below. If the Commission does not authorize PacifiCorp's preferred cost recovery plan, including the crediting of foregone PBR rate increases, PacifiCorp seeks authorization to implement its Alternate Cost Recovery Plan. By executing this proposed Stipulation, no signatory party is endorsing PacifiCorp's Alternate Cost Recovery Plan.

Background

On or about May 5, 1997, PacifiCorp (U 901-E), filed its Transition Plan setting forth its proposals to afford direct access to all of the Company's California retail customers effective January 1, 1998. PacifiCorp's original Transition Plan filing is attached hereto and identified as Stipulation Exhibit A.

On May 30, 1997, pursuant to instructions from ALJ Minkin, PacifiCorp served on all parties of record in R.94-04-031 and I.94-04-032 a Notice of Availability of PacifiCorp's Application for approval of Transition Plan.

The Office of Ratepayer Advocates filed a protest to PacifiCorp's Transition Plan application on July 2, 1997.

In PacifiCorp's May, 1997, Transition Plan filing, the Company proposed a preferred and an alternate approach to cost recovery. The Stipulation sets forth issues that the Parties have resolved between themselves, and proposes that the Commission adopt the agreed-upon positions when authorizing a Transition Plan for PacifiCorp.

Issues Settled by ORA and PacifiCorp

The following sets forth those components of PacifiCorp's proposed Transition Plan agreed-upon by the Parties:

I. <u>Components of Direct Access Proposal.</u>

1. Implementation of Direct Access.

PacifiCorp will provide direct access to all its California customers on January 1, 1998, pursuant to the provisions of AB 1890..

2. Bill Unbundling.

Beginning January 1, 1998, in addition to charges currently detailed on a customer's bill, PacifiCorp proposes to provide a functional separation of the charges as follows:

(a) charges associated with distribution;

(b) charges associated with transmission;

(c) charges associated with research, environmental and energy efficiency programs, and low-income funds; and,

(d) charges associated with generation, including the monthly generation credit and the balance of generation revenue requirement.

(e) PacifiCorp's billings will include a footnote referring to the credit as follows:

"This charge is based on the weighted average price for purchases at the California-Oregon Border. This service is subject to competition. You may purchase electricity from another supplier."

The functional separation described above will be reflected in PacifiCorp's final direct access tariffs and in its preliminary statement thereto.

Customers that select an alternative Electric Service Provider ("ESP") will be charged the same prices as full-service customers, less a market-based energy credit, and credits for transmission and ancillary services.

3. Consumer Education Plan.

PacifiCorp has developed its own Consumer Education Plan ("CEP"), designed specifically for California customers. PacifiCorp's CEP, as modified by the Commission, was approved at the August 1, 1997 meeting in D.97-08-063.

4. Public Purpose Programs.

AB 1890 establishes specific funding levels standards for ongoing public purpose programs for California's three major electric utilities, but provides no funding level requirement for PacifiCorp. PacifiCorp and ORA propose to continue funding low income assistance programs (includes low income conservation services and California Alternative Rates for Energy (CARE) administration) at 1996 levels. The Parties further propose that 1996 funding levels for energy efficiency be reallocated to fund the three remaining Public Purpose programs. PacifiCorp proposes to collect the cost of these programs through a non-bypassable charge which falls within current price levels. The public purpose programs charge will be derived by dividing the 1998 revenue requirement for public purpose programs by forecast 1997 retail sales. The administrative costs of operating the CARE program will be included in the revenue requirement for public purpose programs but the funding for the CARE discount will be collected in a separate charge consistent with current practice.

Public purpose program charges will be detailed on the customer's bill in order for customers to see how much they are currently paying for these programs and to help them decide if they wish to make additional voluntary contributions. All funds collected in this manner shall be forwarded, in a timely manner, to the appropriate Commission-specified fund to the Independent Board and the Low-Income Governing Board for distribution. PacifiCorp and ORA contemplate that the Low-Income Governing Board will subsequently perform an "assessment of customer need" consistent with Section 382 of the Public Utilities Code. PacifiCorp will ask the Low-Income Governing Board to continue funding programs in its service territory through community agencies historically involved in such programs.

5. Reliability and Safety.

PacifiCorp is participating in rulemaking and other Commission proceedings (See, e.g., Ordering Paragraph No. 3 in D.97-01-044, D.96-11-021, I.95-02-015 and

R.96-11-004) to develop standards for service-related performance. Reliability and safety under direct access must be maintained.

6. Independent System Operator and PX.

PacifiCorp's transmission facilities in the State of California are of limited size and extent and are designed and utilized primarily to integrate electrically the Company's northern California loads and resources into the PacifiCorp transmission system. Such integration allows PacifiCorp to optimize the delivery of electrical services in its California service territory.

PacifiCorp has indicated to the California Independent System Operator ("ISO") that the Company would commit control of its California transmission facilities if the ISO concluded that such was desirable. The ISO has concluded that it is not practical for it to assume control over PacifiCorp's northern California transmission facilities. Attached hereto, and hereby incorporated as though fully set forth herein, is Stipulation Exhibit 1, the responsive letter from the ISO. Among other reasons, the ISO concluded that (a) power to serve PacifiCorp's California service territory load would have to be scheduled up the Pacific Intertie, through PacifiCorp's transmission and back down to the load in California; (b) approximately ten (10) Oregon-California border crossings exist at the distribution level presenting additional metering and scheduling problems; (c) the capacity of the existing interconnection from California/ISO facilities in the south, to PacifiCorp's service territory in the north is inadequate to serve the load.

PacifiCorp proposes to commit control of its California transmission system, together with the rest of its extensive transmission system to the Northwest Independent Grid Operator, IndeGO, when IndeGO becomes operational. In the interim, PacifiCorp is establishing retail transaction protocols that will assure both Energy Service Providers ("ESPs") and PacifiCorp's current California customers that the Company will afford direct access commencing January 1, 1998, in a fair, nondiscriminatory manner. See PacifiCorp's September 29, 1997 Testimony, Section 6--Control of Transmission Facilities for a detailed description of proposed protocols.

II. Components of Cost Recovery Proposal.

7. Cost Recovery for Ongoing Obligations and Direct Access Implementation.

PacifiCorp proposes to implement a specific competition transition charge ("CTC"), effective January 1, 2002, for recovery of ongoing obligations which become uneconomic as a result of industry restructuring. These costs may include the above-market costs of purchase power contracts including Qualifying Facilities, and any implementation costs that reduce PacifiCorp's opportunity to recover utility generation-related plant and regulatory assets as found reasonable by the CPUC or the Federal Energy Regulatory Commission. See Section 376 Cal Pub Util Code. Recovery would take place over the remaining life of the obligations through a non-bypassable charge.

This component incorporates ORA-requested modifications to PacifiCorp's initial filing. Eliminated from consideration in this contemplated CTC are stranded costs associated with regulatory assets and flow-through of deferred taxes.

8. Performance-Based Ratemaking

PacifiCorp's California prices are currently adjusted periodically under performance-based ratemaking as described in Section 2.0 of the Company's May 2, 1997 submitted Transition Plan.

PacifiCorp currently has a CPUC-approved PBR which is effective through 1999. If the Company's preferred cost recovery plan, i.e., Plan A, as outlined in the Company's transition plan, is approved by the CPUC, PacifiCorp agrees not to seek recovery of the revenue associated with price index (less productivity factor) changes that would have occurred under the PBR from 1-1-97 through 12-31-99. If PacifiCorp's preferred cost recovery plan is approved, but the CPUC further requires a ten percent rate decrease, the undersigned parties propose that the Commission authorize PacifiCorp to "credit" foregone rate increases that the Company could implement under its PBR towards meeting the ordered rate reduction.

PacifiCorp proposes to track the PBR index mechanism through the scheduled ending date of the PBR in 1999 and to file a delivery service-only PBR in 1998 for implementation, effective January 1, 2000. The assumed starting point for the unbundled delivery services under the post-1999 PBR would be the functionalized 1996 delivery prices escalated through 1999 by applying the overall PBR index adopted in D.92-12-096 to those delivery services. To demonstrate the reasonableness of those delivery services, the Company will submit a functionalized earnings demonstration report similar to the report used to justify extension of the PBR mechanism for the 1997-1999 period. The undersigned parties propose that extension of the described delivery-services PBR should be contingent upon PacifiCorp's earnings demonstration showing that the Company is not earning unreasonable returns.

9. Rate Freeze.

Through December 31, 2001, PacifiCorp is committed to freezing rates for each customer class, rate schedule, contract, and tariff at the same level as the level shown on electric service schedules as of June 10, 1996, if PacifiCorp's preferred Plan A is authorized by the Commission.

10. Rate Reduction Bonds

Rate Reduction Bonds, as established in AB 1890, are available as special financing for a portion of each utility's transition costs. The potential value of the rate reduction bonds is heavily dependent upon the financial considerations of the individual utility and they are not effective in every case. PacifiCorp does not intend to request securitization of transition bonds.

11. Transition Cost Recovery

The bills of customers who continue to buy full electric service from PacifiCorp would be based on current tariff prices. Customers electing to buy power from sources other than PacifiCorp will receive a credit on their bills equal to the relevant market price of electricity and a credit for transmission and ancillary service charges to the extent the latter two costs are billed to the ESP. PacifiCorp will accept the risk that market prices will diverge from the Company's generation costs. At ORA's request, PacifiCorp revised its original Transition Plan to describe the proposed market price with more specificity, as follows.

PacifiCorp proposes to use the Dow-Jones California-Oregon Border ("COB") electric price index, as published in the Wall Street Journal, as the basis of its market price credit during the transition period. This index provides on- and off-peak pricing indexes and also provides a firm and non-firm breakdown. Since firm service is being provided, the Company will base its market credit on the available firm service index. The daily on-peak price indexes will be averaged over the billing period and applied to on-peak hour consumption. The daily off-peak price indexes will be averaged over the billing period and applied to off-peak consumption. The results will be added together to calculate the billing credit. For customers without time of use metering, the Company will use customer class load profiles to develop a weighted average market energy price.

The COB index is appropriate for pricing service in PacifiCorp's northern California service territory because loads in that area can receive capacity and energy from COB which is within the contemplated IndeGO system without incurring further transmission wheeling charges. Other indices, including the PX, are located outside of the IndeGO system. These price indices do not reflect the additional transmission costs that would be incurred to reach the IndeGO system.

COB-based prices will be grossed up for losses in delivery. Customer who buy competitively available ancillary services will receive a credit based on the ancillary service costs in the Company's FERC open access tariff.

12. <u>Functionalized Class Revenue Requirements and Prices</u>:

The Parties agree that PacifiCorp's distribution revenue requirement shall be adjusted to reflect the following deductions: $400,000 associated with customer service and marketing costs and $44,000 of uncollectibles. D.97-08-056 directed that one-third of franchise fees should be allocated to the generation function. PacifiCorp's supplemental filing expressed reservations about this requirement, based on the appropriateness of allocating franchise fees to generation under California law addressing local governmental fees. Southern California Edison Company has filed a petition for modification of D.97-08-056 seeking clarification of this issue. PacifiCorp and ORA agree that the resulting resolution of this issue in response to Edison's petition should be reflected in PacifiCorp's functional revenue allocation.

D.97-08-056 adopted several principles for functionalized interclass revenue allocations. One of those principles was to assign generation revenues residually after all other revenue components have been determined. The three major California utilities' transmission and distribution revenue requirements are relatively close to the corresponding marginal cost revenues, while generation revenue requirements significantly exceed marginal cost revenues. In contrast, PacifiCorp's distribution revenue requirements differ significantly from their related marginal cost revenues.

As a result, it is necessary to modify D.97-08-056's allocation principles for PacifiCorp, by allocating its generation revenue requirement in proportion to its generation marginal cost revenues, allocate transmission revenue requirement as described in ORA's October 1, 1997, testimony. The resulting functionalized class revenues are shown in attached Tables 1 - 6.

Functionalization of Residential Baseline The Parties agree that PacifiCorp's residential baseline rate structure will conform with D.97-08-056's direction to reflect the baseline differential in both distribution and CTC rates.

DATED this 8th day of October, 1997, in San Francisco, California.

PACIFICORP
By: ____________
____

DATED this 8th day of October, 1997, in San Francisco, California.

Jonathan G. Bromson

OFFICE OF RATEPAYER ADVOCATES
By: ____________
____

Functionalized Class Revenues - Table 1
PACIFIC POWER & LIGHT COMPANY
State of California
1998 Functionalized Revenue
Distribution Residual

Line No.	Class / Schedule		Generation Revenues (1)	FERC Transmission Revenues (2)	State Transmission Revenues (3)	Distribution Revenues (4)	Public Purpose Revenues (5)	CARE Surcharge Revenues (6)	CARE Discount Revenues (7)	CPUC Fees (8)	Total Annual Revenue (9)
	Residential										
1	Residential Service	D	10,260	1,741	1,019	16,225	211	274	(499)	46	29,276
2	Multi-Family - Submetered	DS-8	35	7	3	62	1	1	(8)	0	101
3	Multi-Family - Master Metered	DM-9	2	0	0	3	0	0	0	0	6
4	**Total Residential**		$10,297	$1,748	$1,022	$16,290	$212	$275	($507)	$46	$29,383
5	**Commercial & Industrial**										
6	Small General Service - < 20 kW	A-25/AWH-31	1,334	251	104	4,115	42	45	0	7	5,898
7	Small General Service - 20 kW & Over	A-32	1,800	451	202	3,017	40	51	0	7	5,568
8	Large General Service - 100 kW & Over	A-36	2,651	413	249	3,738	52	83	0	12	7,197
9	Large General Service - 500 kW & Over	AT-48	2,245	302	235	1,999	35	67	0	10	4,895
10	Agricultural Pumping Service	PA-20	1,506	291	148	1,622	26	46	0	7	3,646
11	Agricultural Pumping Service - USBR	-	596	-	59	(213)	3	0	0	0	445
12	**Total Commercial & Industrial**		$10,131	$1,708	$997	$14,279	$199	$292	$0	$43	27,649
13	**Total Lighting**		$77	$19	$2	$467	$4	$0	$0	$0	$569
14	**Total Sales to Consumers**		$20,505	$3,475	$2,021	$31,035	$415	$568	($507)	$89	$57,601
	Check		$20,505	$3,475	$2,021	$31,035	$415	$568	($507)	$89	$57,601

Sources:
Line 14 is from Functionalized Revenue Requirement - Table 1 Lines 2 and 3
Column 1 = Line 14 X Functionalized Class Revenues Table 5 Col. 3
Column 2 = Functionalized Class Revenues Table 4 Line 7
Column 3 = Line 14 X Functionalized Class Revenues Table 5 Col. 4
Column 4 = Col. 9 - Col.1 - Col. 2 - Col. 3 - Col. 5 - Col. 6 - Col. 7 - Col. 8
Column 5 = Line 14 X Functionalized Class Revenues Table 5 Col. 6
Column 6 = Functionalized Class Revenues Table 6 Col. 7
Column 7 = Functionalized Class Revenues Table 6 Col. 8
Column 8 = Functionalized Class Revenues Table 8 Col. 9

Functionalized Class Revenues - Table 2
PACIFIC POWER & LIGHT COMPANY
State of California
1998 Functionalized Cents per kWh
Distribution Residual

Line No.	Class / Schedule		Generation Revenues (1)	Ferc Transmission Revenues (2)	State Transmission Revenues (3)	Distribution Revenues (4)	Public Purpose Revenues (5)	CARE Surcharge Revenues (6)	CARE Discount Revenues (7)	CPUC Fees (8)	Total Annual Revenue (9)
	Residential										
1	Residential Service	D	2.69	0.46	0.27	4.26	0.06	0.07	(0.13)	0.01	7.69
2	Multi-Family - Submetered	DS-8	2.28	0.46	0.20	4.05	0.07	0.07	(0.52)	0.00	6.59
3	Multi-Family - Master Metered	DM-9	2.78	0.46	0.28	4.45	0.06	0.08	0.00	0.00	8.11
4	**Total Residential**		2.69	0.46	0.27	4.26	0.06	0.07	(0.13)	0.01	7.68
5	**Commercial & Industrial**										
6	Small General Service - < 20 kW	A-25/AWH31	2.43	0.46	0.19	7.50	0.08	0.08	0.00	0.01	10.75
7	Small General Service - 20 kW & Over	A-32	2.88	0.72	0.32	4.83	0.06	0.08	0.00	0.01	8.92
8	Large General Service - 100 kW & Over	A-36	2.62	0.41	0.25	3.70	0.05	0.08	0.00	0.01	7.12
9	Large General Service - 500 kW & Over	AT-48	2.73	0.37	0.29	2.43	0.04	0.08	0.00	0.01	5.95
10	Agricultural Pumping Service	PA-20	2.68	0.52	0.26	2.88	0.05	0.08	0.00	0.01	6.48
11	Agricultural Pumping Service - USBR	-	2.68	0.00	0.26	(0.96)	0.01	0.00	0.00	0.00	2.00
12	**Total Commercial & Industrial**		2.67	0.45	0.26	3.77	0.05	0.08	0.00	0.01	7.29
13	**Total Lighting**		1.83	0.46	0.05	11.11	0.10	0.00	0.00	0.00	13.55
14	**Total Sales to Consumers**		2.68	0.45	0.26	4.05	0.05	0.07	(0.07)	0.01	7.52

Sources:
Functionalized Class Revenues Table 1 / Functionalized Class Revenue Table 6 Col. 5

Functionalized Class Revenue - Table 3
PACIFIC POWER & LIGHT COMPANY
State of California
1998 Class Functionalization %
Distribution Residual

Class / Schedule		Generation Revenues (1)	FERC Transmission Revenues (2)	State Transmission Revenues (3)	Distribution Revenues (4)	Public Purpose Revenues (5)	Total Annual Revenue (6)
Residential							
Residential Service	D	34.833%	5.909%	3.458%	55.084%	0.716%	100.00%
Multi-Family - Submetered	DS-8	32.407%	6.481%	2.778%	57.408%	0.926%	100.00%
Multi-Family - Master Metered	DM-9	34.674%	5.725%	3.442%	55.446%	0.713%	100.00%
Total Residential		34.824%	5.911%	3.457%	55.092%	0.716%	100.00%
Commercial & Industrial							
Small General Service - < 20 kW	A-25/AWH-31	22.816%	4.291%	1.783%	70.384%	0.727%	100.00%
Small General Service - 20 kW & Over	A-32	32.663%	8.180%	3.667%	54.763%	0.728%	100.00%
Large General Service - 100 kW & Over	A-36	37.322%	5.809%	3.507%	52.632%	0.730%	100.00%
Large General Service - 500 kW & Over	AT-48	46.604%	6.279%	4.883%	41.502%	0.732%	100.00%
Agricultural Pumping Service	PA-20	41.917%	8.099%	4.119%	45.134%	0.731%	100.00%
Agricultural Pumping Service - USBR	-	133.880%	0.000%	13.156%	-47.757%	0.720%	100.00%
Total Commercial & Industrial		37.092%	6.252%	3.650%	52.277%	0.729%	100.00%
Total Lighting		13.490%	3.376%	0.391%	82.023%	0.721%	100.00%
Total Sales to Consumers		35.691%	6.049%	3.519%	54.020%	0.722%	100.00%

Sources:
Column 1 = Functionalized Class Revenue Table 1 Col 1 / (Col 1 + Col 2 + Col 3 + Col 4 + Col 5)
Column 2 = Functionalized Class Revenue Table 1 Col 2 / (Col 1 + Col 2 + Col 3 + Col 4 + Col 5)
Column 3 = Functionalized Class Revenue Table 1 Col 3 / (Col 1 + Col 2 + Col 3 + Col 4 + Col 5)
Column 4 = Functionalized Class Revenue Table 1 Col 4 / (Col 1 + Col 2 + Col 3 + Col 4 + Col 5)
Column 5 = Functionalized Class Revenue Table 1 Col 5 / (Col 1 + Col 2 + Col 3 + Col 4 + Col 5)

Functionalized Class Revenue - Table 4
PACIFIC POWER & LIGHT COMPANY
State of California
FERC Transmission

Line No.	Description		kWh's (1)	¢/kWh (2)	FERC Energy Dollars (1)*(2) (3)	kW (4)	$/kW (5)	FERC Demand Dollars (4)*(5) (6)	Total FERC Dollars (3) + (6) (7)
	Residential								
1	Residential Service	D	380,866,006	0.457	$1,740,558				$1,740,558
2	Multi-Family - Submetered	DS-8	1,531,636	0.457	$7,000				$7,000
3	Multi-Family - Master Metered	DM-9	74,403	0.457	$340				$340
4	**Total Residential**		382,472,045		$1,747,898				$1,747,898
	Commercial & Industrial								
5	Small General Service - < 20 kW	A-25/AWH-31	54,888,613	0.457	$250,841				$250,841
6	Small General Service - 20 kW & Over	A-32				310,832	$1.45	$450,706	$450,706
7	Large General Service - 100 kW & Over	A-36				284,503	$1.45	$412,529	$412,529
8	Large General Service - 500 kW & Over	AT-48				208,603	$1.45	$302,474	$302,474
9	Agricultural Pumping Service	PA-20				200,688	$1.45	$290,998	$290,998
10	Agricultural Pumping Service - USBR	--							$0
11	**Total Commercial & Industrial**				$250,841			$1,456,708	$1,707,549
12	**Total Lighting**		4,201,372	0.457	$19,200				$19,200
13	**Total FERC Transmission**								$3,474,647

Sources:
Pricing

Functionalized Class Revenues - Table 5
PACIFIC POWER & LIGHT COMPANY
State of California
1998 Revenue Requirement Allocation
Based on Long Run Marginal Costs

Class / Schedule		All GTD Marginal Costs (1)	T&D Marginal Costs (2)	Generation Marginal Costs (3)	Transmission Marginal Costs (4)	Distribution Marginal Costs (5)	Per Cent of Revenue (6)
Residential							
Residential Service	D	55.01%	61.64%	50.03%	50.38%	64.29%	50.83%
Multi-Family - Submetered	DS-8	0.19%	0.21%	0.17%	0.17%	0.22%	0.18%
Multi-Family - Master Metered	DM-9	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
Total Residential		55.21%	61.87%	50.22%	50.57%	64.52%	51.01%
Commercial & Industrial							
Small General Service - < 20 kW	A-25/AWH-31	9.88%	14.37%	6.51%	5.16%	16.54%	10.24%
Small General Service - 20 kW & Over	A-32	7.68%	6.22%	8.78%	9.99%	5.34%	9.67%
Large General Service - 100 kW & Over	A-36	9.49%	4.91%	12.93%	12.32%	3.16%	12.49%
Large General Service - 500 kW & Over	AT-48	7.65%	3.27%	10.95%	11.64%	1.30%	8.50%
Agricultural Pumping Service	PA-20	6.52%	5.42%	7.34%	7.32%	4.97%	6.33%
Agricultural Pumping Service - USBR	-	2.90%	2.90%	2.91%	2.90%	2.90%	0.77%
Total Commercial & Industrial		44.13%	37.09%	49.41%	49.32%	34.22%	48.00%
Total Lighting		0.66%	1.04%	0.37%	0.11%	1.26%	0.99%
Total Sales to Consumers		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source:
Col 1 - 5 from Marginal Cost Study - Table 1
Col 6 from Functionalized Class Revenues - Table 6 Col 6

FUNCTIONALIZED CLASS REVENUES - TABLE 6
STATE OF CALIFORNIA
DETERMINATION OF REVENUES AT PRESENT PRICES
DISTRIBUTED BY RATE SCHEDULE
12 MONTHS ENDED DECEMBER 1998

Line No	Account No (1)	Description (2)	Schedule No (3)	Average Customers (4)	MWh (5)	Present Revenues ($000) (6)	CARE Surcharge Revenues (7)	CARE Discount Revenues (8)	CPUC Fees (9)	Line No
	440	**Residential**								
1		Residential Service	D	34,121	380,866	$29,276	$274	($499)	$46	1
2		Multi-Family - Submetered	DS-8	14	1,532	$101	$1	($8)	$0	2
3		Multi-Family - Master Metered	DM-9	3	74	$6	$0	$0	$0	3
4		**Total Residential**		34,138	382,472	$29,383	$275	($507)	$46	4
	442	**Commercial & Industrial**								
5		Small General Service - < 20 kW	A-25	6,418	54,464	$5,865	$45	$0	$7	5
6		Small General Service - 20 kW & Over	A-32	838	62,444	$5,568	$51	$0	$7	6
7		Large General Service - 100 kW & Over	A-36	263	101,143	$7,197	$83	$0	$12	7
8		Large General Service - 500 kW & Over	AT-48	20	82,292	$4,895	$67	$0	$10	8
9		Commercial Water Heating	AWH-31	50	424	$33	$0	$0	$0	9
10		Outdoor Area Lighting Service	OL-15	1,337	1,549	$252	$0	$0	$0	10
11		Airway & Athletic Lighting	OL-42	43	245	$29	$0	$0	$0	11
12		Agricultural Pumping Service	PA-20	543	56,232	$3,646	$46	$0	$7	12
13		Agricultural Pumping Service - USBR	–	341	22,245	$445	$0	$0	$0	13
14		**Total Commercial & Industrial**		9,853	381,038	$27,930	$293	$0	$43	14
	444	**Public Street Lighting**								
15		Street Lighting Service	LS-51	75	676	$132	$0	$0	$0	15
16		Street Lighting Service	LS-52	1	13	$3	$0	$0	$0	16
17		Street Lighting Service	LS-53	130	1,485	$128	$0	$0	$0	17
18		Street Lighting Service	LS-57	0	0	$0	$0	$0	$0	18
19		Street Lighting Service	LS-58	14	202	$25	$0	$0	$0	19
20		**Total Public Street Lighting**		220	2,406	$288	$0	$0	$0	20
21		**Total Sales to Ultimate Consumers**				$57,601	$568	($507)	$89	21
22		**Employee Discount**				($50)				22
23		**Total Sales with Employee Discount**		44,211	765,916	$57,551				23

Source:
Phong

(END OF APPENDIX B)

Appendix C *

Unbundled Revenue Requirement By Class
for
Sierra Pacific Power Company

Revenue Allocation

Rate Class	Total Rev Req (a)	Generation (b)	Transmission (c)	Distribution (d)	CARE (e)	Other PPP (f)	Net Distribution (g) = (d) - (e) - (f)
	$ 39,894,000	$ 21,351,000	$ 2,824,000	$ 15,719,000	$ 116,033	$ 98,000	$ 15,504,967
Residential	21,470,000	10,474,000	1,397,000	9,599,000	55,924	52,741	$ 9,490,335
A-1	8,685,000	4,368,000	582,000	3,735,000	23,115	21,335	$ 3,690,550
A-2	3,657,000	2,594,000	301,000	762,000	12,150	8,983	$ 740,866
A-3	5,829,000	3,828,000	538,000	1,463,000	24,402	14,319	$ 1,424,279
SL	78,000	18,000	2,000	58,000	98	192	$ 57,710
OLS	147,000	39,000	5,000	103,000	215	361	$ 102,424
PA	28,000	23,000	0	5,000	129	69	$ 4,803
		21,344,000	2,825,000	15,725,000	116,033	98,000	

Average Rate, $/kWh

Rate Class	MWH Sales (h)	Generation $/kWh (i) = (b) / (h)	Transmission $/kWh (j) = (c) / (h)	Distribution $/kWh (k) = (d) / (h)	CARE $/kWh (l) = (e) / (h)	Other PPP $/kWh (m) = (f) / (h)	Net Distribution $/kWh (n) = (g) / (h)
Total Average	479,662	0.04451	0.00589	0.03277	0.00024	0.00020	0.03232
Residential	235,346	0.04450	0.00594	0.04079	0.00024	0.00022	0.04033
A-1	93,951	0.04649	0.00619	0.03975	0.00025	0.00023	0.03928
A-2	49,385	0.05253	0.00609	0.01543	0.00025	0.00018	0.01500
A-3	99,183	0.03860	0.00542	0.01475	0.00025	0.00014	0.01436
SL	399	0.04511	0.00501	0.14536	0.00025	0.00048	0.14464
OLS	875	0.04457	0.00571	0.11771	0.00025	0.00041	0.11706
PA	523	0.04398	0.00000	0.00956	0.00025	0.00013	0.00918

Rate Class	CARE Sales
Total	471,618
Residential	227,302
A-1	93,951
A-2	49,385
A-3	99,183
SL	399
OLS	875
PA	523

(END OF APPENDIX C)

A. 97-05-011 et al.
D. 97-12-093

Commissioners Jessie J. Knight, Jr. and Josiah L. Neeper, Dissenting in Part:

We join our colleagues in supporting this order with the exception of one important aspect which forces us to partially dissent from the majority on an issue that continues to haunt the purity of tomorrow's free market in the electric industry. This decision opens to competition heretofore closed markets that are serviced by all investor owned utilities in the state. Also, the decision ensures that the regulatory framework that governs small and multi-jurisdictional utilities is restructured. However, the majority's decision unfortunately dangles an improper economic option to these utilities by suggesting that PacificCorp or Sierra Pacific could offer its customers market-based rates, if they would agree to sell and buy all of their power out of California's government-mandated Power Exchange. From the beginning of the initial debate in 1993 to the present inception and creation of the California Power Exchange, we have not supported the mandated requirement that the big three investor owned utilities buy and sell their power to the Power Exchange, as described in Decision 95-12-063. Therefore, we certainly do not support the requirement or even the hint that the small and multi-jurisdictional utilities should do the same, although we have been required to embrace the institution as the result of its embodiment as an essential part of AB 1890. The democratic process of achieving California's comprehensive legislation in AB 1890 permitted the establishment of a government-established Power Exchange as a *quid quo pro* for direct access. This was a proper balancing of divergent interests in order for the benefits of electric restructuring to be realized without costly litigation and delay. However, to go beyond this for the small and multi-jurisdictional utilities is the issue on which we must partially dissent from the majority. This was NOT part of the envisioned intent nor prescribed language in AB 1890.

In some recent decisions by this Commission that we have opposed, our agency has already incrementally skewed the newly emerging market in favor of California's Power Exchange. Not only has the Commission provided the California Power Exchange with guaranteed customers to support its operation, it has taken steps to support a rate design before the Federal Energy Regulatory Commission that further provides economic advantage to the California Power Exchange vis-a-vis other new and growing power exchanges in the state. It has accomplished this unfortunate circumstance by collecting the development costs from these same captive customers in an up-front charge by the California Power Exchange. Such a subsidy clearly provides the California Power Exchange with an unfair competitive advantage over the other competing exchanges in the state, thus undermining the competitiveness of a market this Commission has struggled so long and hard to create.

We continue to oppose providing unfair and anti-competitive support to the California Power Exchange, either in the form of guaranteed customers or subsidies from captive customers. To do so will only serve to distort the marketplace, reduce the level and vigor of competition and undermine innovative alternatives. The California Power Exchange should have to compete <u>**on its own without government intervention**</u> or special considerations. If it cannot, it has no place in the electric marketplace of tomorrow. Let the market dictate its future.

Dated December 16, 1997 in San Francisco, California.

/s/ Jessie J. Knight, Jr.
Jessie J. Knight, Jr.
Commissioner

/s/ Josiah L. Neeper
Josiah L. Neeper
Commissioner

A. 97-05-011 et al.
D. 97-12-093

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Josiah L. Neeper
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