ORDER NO. 98-191

ENTERED MAY 05 1998

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 94 (Phase II)

In the Matter of the Revised Tariff Schedules in Oregon filed by PACIFICORP, dba Pacific Power and Light Company.	)))	ORDER

DISPOSITION: DISTRIBUTION-ONLY AFOR APPROVED

INTRODUCTION

In this order, we approve an alternative form of regulation (AFOR) for PacifiCorp, dba Pacific Power and Light Company (PacifiCorp), pursuant to ORS 757.210(2). The new regulatory framework, which applies to PacifiCorp's distribution function only, will improve distribution cost management and benefit customers by providing rate stability, the potential for revenue sharing, and increased service quality measures to ensure safe and reliable service. The AFOR also provides incentives to motivate PacifiCorp to invest in sustainable and efficient energy resources.

The AFOR incorporates many aspects of a stipulated AFOR previously submitted by PacifiCorp and the Public Interest Parties[1], as applied to the distribution function only. The regulatory framework also includes several modifications to the prior plan as set forth in our January 15, 1998, Draft Order, as well as certain modifications proposed in PacifiCorp's February 18, 1998, Conditional Acceptance.

The main features of the distribution-only AFOR, set forth in Appendix A, are:

- Revenue cap for distribution revenues.

- Increased service quality performance measures to ensure safe and reliable service.

- Revenue sharing between customers and PacifiCorp for all earnings outside a predetermined earnings range.

[1] The Public Interest Parties consist of the Citizens' Utility Board, the Natural Resources Defense Council, the Oregon Department of Energy, and the Northwest Conservation Act Coalition.

- A non-bypassable system benefits charge and renewable resource incentive to encourage investment in sustainable energy resources and allow PacifiCorp to recover other investments in energy efficiency.

PacifiCorp is not required to accept the AFOR set forth in this order. PacifiCorp shall notify the Commission within 20 days of the date of this order whether the company will accept the alternative plan of regulation set forth in this order. If PacifiCorp accepts the terms of this order, the new regulatory framework for the utility's distribution function will begin on the date PacifiCorp notifies the Commission of its acceptance. If PacifiCorp elects not to implement the offered AFOR, no change will be made in the manner in which the utility is currently regulated.

INTRODUCTION

Procedural Background

PacifiCorp initiated this docket on September 1, 1995, with the filing of revised tariff schedules designed to increase rates to its Oregon retail electric customers. It also requested the approval of an AFOR, as authorized under ORS 757.210(2).

At the request of the parties, this docket was divided into two phases. Phase I was limited to revenue requirement issues under traditional regulation (including rate spread and rate design). On July 10, 1996, we concluded Phase I by adopting a stipulated 4 percent rate increase. *See* Order No. 96-175.

Phase II was designed to address AFOR-related issues, decoupling, service quality standards, system benefits charges, and renewable resource incentives. On October 23, 1996, PacifiCorp and the Public Interest Parties (collectively referred to as the Joint Parties) filed a Stipulated AFOR intended to resolve all outstanding Phase II issues.

After conducting hearings and holding the case in abeyance until after the 1997 Oregon Legislative Assembly had adjourned, we rejected the Joint Parties' Stipulated AFOR in Order No. 97-371. We based our decision on the finding that the Stipulated AFOR failed to provide sufficient customer benefits as required by ORS 757.210(2)(b).

In rejecting the Stipulated AFOR, however, we stated our intent to pursue other regulatory options for PacifiCorp and scheduled a hearing to obtain additional input from the parties. We also requested the parties to provide written answers to a series of questions, including whether the parties were still interested in pursuing an AFOR.

On October 16, 1997, Michael Grant, an Administrative Law Judge for the Commission, presided over a hearing before Commissioners Eachus, Smith, and Hamilton. The following appearances were entered: Paul Graham, Assistant Attorney General, on behalf of Staff; Jim Fell, attorney, on behalf of PacifiCorp; Melinda Horgan, attorney, on behalf of the Industrial Customers of the Northwest Utilities (ICNU); Bob Jenks, authorized representative, on behalf of the Citizens Utility Board (CUB); Keith Kutler, attorney, on behalf of the Oregon Committee for Fair Utility Rates (OCFUR); Sheryl Carter, authorized representative, on behalf of the Natural Resources Defense Council; Nancy Hirsh, authorized representative, on behalf of the Northwest Conservation Act Coalition; and Peter West, authorized representative, on behalf of Renewable Northwest Project.

STATUTORY STANDARD

ORS 757.210(2) authorizes this Commission to approve an alternative form of regulation plan for electric utilities. The statute provides the Commission with the flexibility to set rates and revenues and determine a method for changes in rates and revenues using alternatives to cost-of-service rate regulation. It states:

> Any alternative form of regulation plan shall include provisions to ensure that the plan operates in the interests of utility customers and the public generally, results in rates that are just and reasonable, and may include provisions establishing a reasonable range for rate of return on investment. In approving a plan, the commission shall, at a minimum, consider whether the plan:
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> (A) Promotes increased efficiencies and cost control;
> (B) Is consistent with least-cost resources acquisition policies;
> (C) Is consistent with maintenance of safe, adequate and reliable service; and
> (D) Is beneficial to utility customers generally, for example, by minimizing utility rates.

DISTRIBUTION-ONLY AFOR

At the October 16 hearing, the Joint Parties proposed an AFOR that would apply only to the distribution function of PacifiCorp's Oregon operations. The Joint Parties based the proposal primarily on the terms contained in the previously rejected Stipulated AFOR, as applied to the distribution function only.[2] The Joint Parties stated that a distribution-only AFOR made sense, because it is likely that the distribution function will continue to be regulated by this Commission to ensure control over the essential service of delivering electricity.

After our review, we agreed with many elements of the Joint Parties' proposal. We further determined, however, that certain modifications were necessary to ensure that the plan meets the statutory criteria set forth in ORS 757.210(2). These modifications relate primarily to service quality standards, earnings band review, and annual price changes. We incorporated these modifications with the Joint Parties' proposal and set forth the revised distribution-only AFOR in a January 15, 1998, Draft Order.

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[2] The terms of the Stipulated AFOR are set forth in Appendix A of Order No. 97-371.

On February 18, 1998, PacifiCorp filed a Conditional Acceptance of the distribution-only AFOR offered in the Draft Order, subject to Commission approval of four modifications. Staff and ICNU subsequently filed comments in response to PacifiCorp's proposed modifications.

The Commission has reviewed PacifiCorp's Conditional Acceptance and the comments filed in response. After consideration, we agree with three of PacifiCorp's proposed modifications, and have revised the AFOR accordingly. For reasons discussed below, we do not agree with PacifiCorp's proposed modification with regard to bond ratings.

TERMS OF APPROVED PLAN

The approved distribution-only AFOR is attached as Appendix A. For purposes of our discussion, we summarize its major features below:

1. *Term of Plan:* The distribution-only AFOR plan shall begin on the date that PacifiCorp notifies the Commission of its acceptance and will run through June 30, 2001. With our approval, PacifiCorp will be allowed to extend the plan an additional three years. PacifiCorp or the Commission may, at any time, initiate a reevaluation of all aspects of the AFOR in case of major industry change or corporate structural change, or if the company fails to maintain minimum bond ratings. The Commission also may terminate the plan if PacifiCorp fails to abide by any provisions of the plan, including those contained in the service quality measure agreement.

In our Draft Order, we previously stated that, if accepted by PacifiCorp, the AFOR would be effective on January 1, 1998. In its comments to PacifiCorp's Conditional Acceptance of that Draft Order, ICNU opposed implementation of the plan on that date, stating that the alternative regulatory mechanism should not be retroactive from the date of the final order. We agree and with the exception of service quality standards addressed in Section 9 below, have modified the AFOR to provide that the plan be effective on the date PacifiCorp notifies the Commission of its acceptance.

2. *Initial Price Change:* In Phase I of this proceeding, we approved a stipulated 4 percent overall rate increase, effective July 15, 1996. *See* Order No. 96-175. That rate increase is not affected by the AFOR and remains in place.

3. *Annual Price Change:* PacifiCorp will be allowed to implement annual price adjustments during the term of the plan. The maximum percentage annual change will be established by an index based on the forecast change in the GDP Price Index, offset by a 0.3 percent productivity adjustment. PacifiCorp may choose to request less than the allowed price increase and may request a price decrease at any time. The company will apply any index-based price decrease on a mandatory basis except when earnings are below the earnings band.

The company shall limit the overall increase to 2 percent in any one year, beginning July of each year, and to a total of 5 percent over the term of the plan. This 5 percent overall cap is a reduction of the Joint Parties' original 6 percent figure and reflects the shorter term of the plan.

4. Revenue Cap: A revenue cap will be applied to distribution revenues. Under this mechanism, temperature adjusted actual sales revenues for each major customer class will be compared to a predetermined revenue cap for that class. Any differences will be collected in a balancing account for distribution (collection) the following year.

5. Earnings Band: Beginning July 1, 1999, the AFOR will include an annual earnings review and potential rate adjustment based on overall company earnings in its Oregon jurisdiction for the prior calendar year. The initial return on equity (ROE) benchmark will be set initially at 10 percent, and be updated annually for each earnings review.

If PacifiCorp's earnings are within 250 basis points[3] above or below the ROE benchmark, there will be no earnings band adjustment. If earnings are more than 250 basis points above or below the ROE benchmark, the company will make an earnings band adjustment as specified in Appendix A. The company's capital structure will consist of 46.3 percent long-term debt, 7.1 percent preferred stock, and 46.6 percent common equity, and will remain constant for the term of the AFOR.

This earnings band and benchmark ROE differ from the Joint Parties' original proposal. For example, the Joint Parties originally proposed that the initial ROE benchmark be set at 11.25 percent. We believe that a 11.25 percent benchmark is too high and have reduced it to 10 percent. Given the utility's current ROE level[4], we believe that the use of the Joint Parties' higher figure would have increased the likelihood that the company's earnings would fall below the earnings band, thereby requiring increased charges to customers. We also modified the Joint Parties' proposal to require that the benchmark ROE be adjusted annually pursuant to the indexing mechanism advocated by Staff. *See* Staff 12/Thornton/9.

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[3] One hundred basis points is equal to one percentage point.

[4] In our January 15, 1998, Draft Order, we took official notice of the fact that PacifiCorp's most recent semiannual report of operations, for the 12 month period ending June 30, 1997, showed "annualized actual" results (including regulatory adjustments) of 9.65 percent ROE using Pacific's proposed capital structure and 10.14 percent ROE using Staff's proposed capital structure. PacifiCorp objected to that notice pursuant to OAR 860-014-0050 and proposed the Commission replace references to "annualized actual" results with references to its "adjusted actual" results. "Actual adjusted" results are results including Type 1 adjustments, such as removal of activity not related to the review period, normalizing water and weather conditions, and other significant ratemaking adjustments not reflected in the company's books. "Annualized actual" results, on the other hand, involve Type 2 adjustments. They include Type 1 adjustments, as well as additional changes to make the current review period more representative of what earnings will likely be in the future. These additional adjustments might include removing the effects of nonrecurring events and annualizing such things as a wage increase that took effect during the review period.

We agree that the AFOR should use only Type 1 results of operations for an earnings review. In determining whether the company is required to make refunds, the Commission should use the actual, historic earnings, with limited ratemaking adjustments. However, as Staff points out, official notice is taken here to support a benchmark return on equity for an earnings band that applies in the future. Because the reference is for purposes of establishing a benchmark on a going-forward basis, we believe that it is proper to take into account Type 2 adjustments, which are designed for that very purpose. Accordingly, we adhere to our official notice of the company's "annualized actual" results of operations.

We also modified the earnings band to allow more sharing with customers. The Joint Parties originally proposed no sharing until PacifiCorp's earnings fell 350 basis points above or below the benchmark ROE. We believe that revenue sharing should begin once the utility's earnings fall outside of 250 basis points from the benchmark ROE and have approved a two-tier band to allow more revenue sharing.

6. Annual Earnings Review: PacifiCorp will provide an annual earnings report for the most recent prior calendar year by April 30 of each year, beginning in 1999 for the 1998 calendar year. The report will be used to demonstrate PacifiCorp's earnings as measured by ROE and to verify that the company's earnings are within the formalized earnings band.

PacifiCorp will also provide, for informational purposes, separate allocated revenues, costs and rate base for generation, transmission, and distribution functions.

7. Adjustments for Major Events: Certain changes to PacifiCorp's costs caused by "major events" outside the company's control will be reflected in any annual price change. "Major events" are limited to changes in Federal/State/Local taxes, including the enactment of an energy related tax.

8. Rate Spread and Rate Design: Until the Commission issues an order in the generic cost of service proceeding (UM 827), PacifiCorp will use the same rate spread for AFOR price increases approved in Order No. 96-175. After the Commission issues an order in UM 827, PacifiCorp shall file a proposal to implement the Commission's findings before its next AFOR rate change, but no more than six months after the date of the UM 827 order.

9. Service Quality Standards: Eight performance measures for evaluating service quality, as well as revenue requirement deductions for poor performance, are be included in the AFOR. The purpose of the performance measures is to provide a mechanism to ensure service quality is maintained at current or improved levels subsequent to the implementation of the AFOR. The service quality performance measures will be effective for a period of ten years, beginning in January 1998, and independent of the existence of any AFOR plan.

These service quality standards are significantly more comprehensive than those originally proposed by the Joint Parties. Although the original service quality standards were based, in part, on earlier proposals by our Staff, we do not believe that they are sufficient to maintain adequate service quality and safety levels. Accordingly, we have modified the service quality standards to conform them more closely to those approved in the merger between Enron Corp. and Portland General Electric Company. *See In the Matter of the Application of Enron Corp. for an Order Authorizing the Exercise of influence over Portland General Electric Company*, UM 814, Order No. 97-196.

These increased service quality performance measures are set forth in Appendix D and incorporated in the distribution-only AFOR approved in this order. These measures are patterned after those adopted in UM 814, with minor modifications to address company-specific differences. They also have been modified, at PacifiCorp's request, to: (1) conform the definition of "major event" to the definition contained in OAR 860-023-0080, which was adopted after the service quality standards were developed in UM 814; (2) adapt certain provisions to conform them more closely to PacifiCorp's programs; and (3) clarify the breadth of Commission discretion to reduce or waive certain financial penalties based on evidence of extenuating or mitigating circumstances.

10. Renewable Resources: The AFOR includes an incentive for PacifiCorp to acquire renewable resources at costs that are lower than were projected in the company's 1995 least-cost plan (RAMPP-4), or any subsequently acknowledged least-cost plan in effect at the time the project begins commercial operation.

11. System Benefits Charge: The AFOR includes a system benefits charge (SBC) on distribution services that is designed initially to recover all costs of Demand-Side Management (DSM) programs and the incentives for the development of renewable resources. The SBC charge is non-bypassable.

12. Bond Ratings: During the term of the AFOR, PacifiCorp shall be required to maintain bond ratings for senior debt with Moody's and Standard & Poors (S&P) of at least Baa2 and BBB, respectively. If the company's bond ratings fall below these levels, the company or the Commission may request reevaluation and possible termination of the AFOR plan.

In its Conditional Acceptance, PacifiCorp requested that the Commission require only that the company maintain "investment grade" bond ratings for senior debt rather than those specified above. PacifiCorp contends that the change is appropriate to avoid a possible termination of the AFOR due to a general downgrading of electric utility debt or other events that are expected to have a short term effect on bond ratings. However, as Staff points out, PacifiCorp's current rating with Moody's for senior securities is A3, two levels above that required in the AFOR (Baa2). Lowering the minimum grade to "investment grade" (Baa3) would prevent the Commission from taking any action until the company's bond rating falls below the lowest investment grade and into speculative grade (Ba1). We need to have the opportunity to reevaluate the plan before such jeopardy occurs. Furthermore, we note that a bond rating fall to Baa3 or lower doesn't automatically terminate the AFOR; it only allows the Commission (or the company) the option to reevaluate the alternative regulatory mechanism.

COMMISSION FINDINGS

We find that the alternative regulatory mechanism set forth in Appendix A meets the statutory criteria of ORS 757.210(2)(a) and should be approved for PacifiCorp's Oregon retail operations. At the outset, we believe that a distribution-only AFOR makes sense in today's changing regulatory environment. We acknowledge the possibility that power generation could become a competitive business that ultimately would operate without traditional price regulation. Transmission services will likely be provided by an independent grid operator regulated by the Federal Energy Regulatory Commission (FERC). In contrast, distribution services will remain a natural monopoly. The financial incentives associated with the provision of reliable distribution service implicate important efficiency, equity, and environmental concerns.

We also believe that the approved AFOR plan operates in the interests of utility customers and the public generally. First, the alternative regulatory mechanism will promote increased efficiencies and cost control for the distribution function by basing rate changes on a general measure of inflation reduced by a productivity offset. *See* ORS 757.210(2)(b)(A). Because PacifiCorp will not be able to pass through to customers any specific distribution cost increases under the plan, the company will be pressured to pursue efficiencies and reduce costs.

Second, the plan is consistent with least-cost resources acquisition policies, as it contains a renewable resources incentive, and a non-bypassable system benefits charge to address DSM cost recovery. *See* ORS 757.210(2)(b)(B). These provisions will encourage investment in sustainable energy resources and allow PacifiCorp to recover other energy efficiency investments.

The alternative regulatory mechanism also includes a revenue cap designed to help sever the link between profits and kilowatt-hour sales. Under this mechanism, temperature adjusted actual sales revenues of each major customer class will be compared to a predetermined revenue cap for that class, and any differences will be collected in a balancing account for recovery the following year. This ensures that PacifiCorp's ability to recover distribution system costs will be independent of retail kilowatt-hour use.

The revenue cap mechanism is particularly valuable as applied here to distribution related revenues. First, the distribution system costs are relatively fixed in the short term. Thus, unlike the generation system, distribution costs are much less sensitive to fluctuations caused by the amount of kWh use. Second, the electric industry is undergoing significant change. The adoption of a decoupling mechanism applied solely to the distribution function may provide insight into the benefits of applying similar mechanisms to a distribution-only company. Finally, the decoupling mechanism will reduce the potential for profits from any new PacifiCorp marketing effort designed to increase kWh use through the sale of new electric devices.

Third, the approved plan is consistent with the maintenance of safe, adequate, and reliable service. *See* ORS 757.210(2)(b)(C). The AFOR includes service quality measures that the Commission currently lacks authority to impose. These increased standards, which shall remain in effect for a period of ten years, include eight performance measures for evaluating service quality on an annual basis with increased penalty levels. These provisions also provide the Commission with the discretion to return to customers any unspent funds targeted for service quality activities in the event of substandard performance. This will preclude the opportunity for the company to increase earnings by cutting costs inappropriately. Furthermore, the standards contain detailed reporting requirements and inspection programs to ensure compliance with all service and safety standards. These requirements, combined with a comprehensive list of definitions, will greatly increase our ability to enforce these provisions, if necessary.

Finally, the distribution-only AFOR is beneficial to utility customers generally. *See* ORS 757.210(2)(a)(D). The plan requires distribution related price decreases if warranted under the price adjustment mechanism. Any rate increases under the plan are capped at 2 percent per year, and because of the productivity offsets, will always be less than the general rate of inflation. Another provision prevents PacifiCorp from automatically passing through to customers any costs resulting from the passage of an energy tax. This will provide PacifiCorp further incentive to diversify its energy resource portfolio. These provisions, along with the plan's revenue cap, revenue sharing requirements, and service quality measures, will help ensure that the plan results in benefits for PacifiCorp's customers.

DEFERRED PHASE I ISSUES

As indicated above, we concluded Phase I of this docket by adopting a stipulated agreement between PacifiCorp and Staff intended to resolve a majority of identified issues related to traditional, cost-of-service regulation. *See* Order No. 96-175. In that order, we also identified seven contested issues, five of which we deferred for resolution in Phase II: Upper Klamath River Basin/United States Bureau of Reclamation (UKRB/USBR) allocation; decoupling; system benefits charge; functionalized billing; and service quality standards.

In this order approving a distribution-only AFOR, we have resolved the issues relating to decoupling, system benefits charge, and service quality standards. The issue relating to functionalized billing, originally raised by the Public Interest Parties, was effectively withdrawn with the Joint Parties' submission of the Stipulated AFOR and was not pursued in subsequent proceedings. Thus, the only remaining issue relates to the UKRB/USBR allocation, which we now find has been rendered moot by subsequent events.

The UKRB/USBR allocation issue, raised by J. Tim Watson, an intervenor, relates to the jurisdictional allocation of contract rates being paid by certain irrigation customers in the Klamath Falls area. These customers receive discount rates in exchange for water rights for hydroelectric projects on the Klamath River. Watson expressed concern that the entire discount associated with these contracts is being allocated to the Oregon jurisdiction, while only some 55 percent of the direct costs and benefits of the generating projects are allocated to this state.

During the Phase I proceeding, Pacific responded that all costs, including the Klamath River generating resources, are allocated in accordance with the PacifiCorp Interjurisdictional Task-Force on Allocations (PITA) Accord Method. Because the PITA Accord Method was developed jointly by PacifiCorp's seven state commissions and represents a balancing of the interests of all jurisdictions, Pacific contended that it would be inappropriate to unilaterally change one item in isolation from all others.

During the pendancy of this hearing, PITA has revisited the methodology used to allocate jurisdictional results of operations and has modified the Accord Method to reflect an agreement among the Pacific Division Jurisdictions UKRB/USBR cost allocations. These revisions are set forth in a Modified Accord Agreement, dated March 20, 1998, which is attached as Appendix E.[5] Our Staff has signed the agreement, which is expected to be ratified in the near future by all PITA members. Under the revised methodology, PacifiCorp will allocate the discount among all states receiving allocated benefits from the Klamath River hydroelectric facilities, including California, Idaho, Montana, Oregon, Washington, and Wyoming.

Inasmuch as the concerns raised by Watson have been addressed by PITA, we need not further address this issue at this time. We note, however, that PITA's recommendations are not binding upon this Commission, and that the modified methodology will be subject to review in any subsequent company rate proceeding in Oregon.

CONCLUSION

Based on the foregoing, the Commission concludes that the alternative form of regulation, set forth in Appendix A, meets the statutory requirements of ORS 757.210(2) and should be approved.

PacifiCorp shall notify the Commission within 20 days of the date of this order whether the company will accept the AFOR set forth in this order. If PacifiCorp accepts the terms of this offer, the new regulatory framework for the utility's distribution function will take effect on the date it notifies the Commission of its acceptance. If PacifiCorp elects not to implement the AFOR, no change will be made in the manner in which the utility is currently regulated.

ORDER

IT IS ORDERED that:

1. The alternative form of regulation, set forth in Appendix A and to be applied to PacifiCorp's distribution function for its Oregon operations, is approved.

2. PacifiCorp shall notify the Commission within 20 days of the date of this order whether the regulatory framework set forth in this order is acceptable. If PacifiCorp accepts the terms of this order, the distribution-only AFOR will take effect on the date PacifiCorp notifies the Commission of its acceptance.

[5] Pursuant to OAR 860-014-0050, a party may object to a fact noticed within 15 days of this order.

3. If PacifiCorp elects not to implement the offered AFOR, no change will be made in the manner in which the utility is currently regulated.

Made, entered, and effective ____________________.

Ron Eachus Chairman	**Roger Hamilton** Commissioner

Commissioner Joan Smith concurs in part and dissents in part:

While I overall support this order and the alternative form of regulation approved for PacifiCorp, I have significant misgivings concerning the decoupling mechanism. Several years ago, the Commission, in docket UM 409, considered the wisdom of decoupling mechanisms as a means to further the acquisition of cost-effective conservation and energy efficiency in general. While the majority of the Commission supported decoupling in that order, I did not and authored a vigorous dissent against decoupling. I encourage you to read that dissent, which is attached as Appendix F. My reasons stated in that dissent still hold, and my opposition to decoupling is even stronger today. The ultimate objective of decoupling is to change corporate behavior. Decoupling, we are told by its supporters, will cause industry leaders to shift their focus from increasing kWh sales to other objectives, perhaps even marketing energy efficiency including conservation. Does anyone really believe this decoupling mechanism will change PacifiCorp's behavior? Of course it will not. Further, the Joint Parties' stipulated decoupling mechanism does not even accomplish the short-term financial objective of breaking the link between PacifiCorp's profitability and its kWh sales level. This record is perfectly clear that PacifiCorp's earnings will increase as kWh sales increase because we are only decoupling distribution related revenues. PacifiCorp is still a fully vertically integrated company.

Why then do I support this proposal? I had little choice. The approved AFOR includes the implementation of a ten-year term service quality performance mechanism. PacifiCorp currently has no such mechanism in place. The Commission, absent enabling legislation, cannot impose a service quality mechanism on PacifiCorp that includes financial penalties. Therefore, to have such a mechanism implemented, it must be agreed to by the utility.

In the PGE case, we were able to obtain the company's acquiescence, by requiring it as a condition for approval of PGE's merger with Enron. With regard to PacifiCorp, our only current option is to require acceptance of our proposed service quality mechanism as a condition of implementing an AFOR. PacifiCorp and the Joint Parties want a decoupling mechanism in their AFOR. Thus again, I had little choice.

Joan H. Smith
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. Arequest for rehearing or reconsideration must be filed with the commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to ORS 756.580.

ALTERNATIVE FORM OF REGULATION
FOR PACIFICORP, d.b.a. PACIFIC POWER AND LIGHT

AS APPLIED TO ONLY THE DISTRIBUTION
FUNCTION FOR OREGON OPERATIONS

1. <u>Term of Plan:</u>

The distribution-only, alternative regulation plan shall begin on the date that PacifiCorp notifies the Commission of its acceptance of the plan, with the exception of the service quality standards, and run through June 30, 2001.

During the last year of the plan, PacifiCorp shall make a recommendation regarding the continuation of the plan and submit this recommendation to the Commission for review. Review criteria will focus on the objectives of the AFOR, including the legislative standards of alternative regulation plans set forth in ORS 757.210(2). Should PacifiCorp wish to continue the plan, the company agrees to make a general rate filing under ORS 757.210(1) if directed by the Commission within 120 days of such notification.

With Commission approval, PacifiCorp would be allowed to continue the plan unchanged for an additional three years.

PacifiCorp or the Commission may, at any time, initiate a reevaluation of all aspects of the distribution-only AFOR in case of major industry change or corporate structural change, or if the company fails to maintain minimum bond ratings (*See* Section 12, *infra*). The Commission may terminate the plan if PacifiCorp fails to abide by any provisions of the plan, including those in the service quality measure agreement (*See* Section 9, *infra*).

2. <u>Initial Price Change:</u>

The 4 percent overall price increase approved in Order No. 96-175 shall remain in place.

3. <u>Index-Related Price Changes:</u>

PacifiCorp shall be allowed to implement index-related price adjustments during the term of the distribution-only AFOR. The maximum percentage price change shall be established by a price index based on the forecast change in the GDP Price Index (published by DRI/McGraw-Hill), offset by a productivity adjustment. The annual productivity adjustment shall be 0.3 percent for distribution functions.

The first index-related price change may occur as soon as practicable after the company notifies the Commission of its acceptance of the plan. Subsequent index-related price changes may occur thereafter annually on July 1.

PacifiCorp shall limit the overall increase to 2 percent in any one year (beginning July 1 of each year) and to a total of 5 percent over the term of the plan. These caps apply to the percentage increase in the distribution portion of base rates.

PacifiCorp may choose to request less than the allowed price increase and may request a price decrease at any time. Any foregone increase may be carried forward and applied later; any increase subsequently applied shall be indexed as if it had been applied when first eligible. The company shall apply any index-based price decrease on a mandatory basis except when earnings are within the sharing zones (*See* Section 5, *infra*).

The potential index-related changes, prior to application of any carryovers and any annual or total limits, shall be calculated as follows:

> Initial Price Change: The November 1997 DRI forecast average GDPPI (index) for the two quarters ending June 30, 1998, divided by the average GDPPI for the four quarters ending June 30, 1997, minus 1, minus a productivity offset of 0.375 percent (reflecting 15 months).
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> July 1, 1998 (to be filed May 15, 1998): The current year's April DRI forecast average GDPPI for the four quarters ending June 30, 1999, divided by the prior used forecast average GDPPI for the two quarters ending June 30, 1998, minus 1, minus a productivity offset of 0.225 percent (reflecting 9 months).
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> July 1, 1999, and July 1, 2000 (to be filed by May 1 of that year):
> The current year's April DRI forecast average GDPPI for the four quarters ending June of the following year, divided by the prior used forecast average GDPPI for the four quarters ending June of the current year, minus 1, minus a productivity offset of 0.3 percent.

At PacifiCorp's discretion, the initial and the July 1, 1998 index-related changes may be combined into one index-related change effective July 1, 1998. In this case, both the overall index-related change and the increase applied to any customer class (*see* Section 8, *infra*) would be limited to 4 percent.

The price changes will apply to base rates only and would not be affected by adjustments to base rates from PacifiCorp's DSM cost recovery and incentive mechanism (Schedules 191 and 192), the implementation of a system benefits charge, BPA exchange benefits (Schedule 98), deferred revenue impacts (Schedule 93), revenue decoupling adjustments or stranded cost mitigation as agreed to by the Commission. Price changes due to these adjustments will continue to occur independent of base price changes.

Adjustments for external major events (Section 7), specific performance measures (Section 9), and credits/surcharges to customers resulting from earnings reviews (Section 6) or application of the revenue cap (Section 4) may be made at the same time as any index-related price change.

4. <u>Revenue Cap:</u>

A revenue cap shall be applied to distribution revenues. Under this mechanism, temperature-adjusted actual sales revenues of each major customer class shall be compared to a predetermined revenue cap for that class. Any differences shall be collected in a balancing account for distribution (or collection) the following year. The accruals to the balancing account will begin as of the first full month following the date of PacifiCorp's acceptance of the plan.

The revenue cap for each class shall be set equal to the forecasted year test revenues for that class multiplied by the distribution proportion of the marginal cost of service, adjusted for sales growth to reflect the calendar-year new sales levels. The revenue cap also shall be indexed by the distribution price index consistent with the actual application of price changes. The revenue cap formula is:

$\text{Revenue Cap}_c\,(\text{year}) = \text{Revenue Cap}_c\,(\text{year-1}) \times [1+\text{price index}_c] \times [1+\text{sales index}]$

The revenue cap price index will be developed for each major customer class by applying the distribution AFOR price index (GDP Price Index less productivity factor of 0.3%) to customer classes. Appendix B describes mechanically how the revenue cap for distribution would work under an AFOR that only price-indexes distribution revenues. This is further clarified by PacifiCorp correspondence dated November 10, 1997, which is attached as Appendix C.

5. <u>Earnings Band:</u>

Beginning July 1, 1999, the AFOR will include an annual earnings review and potential rate adjustment based on overall company earnings in its Oregon jurisdiction for the prior calendar year. If PacifiCorp's earnings are within 250 basis points above or below an ROE benchmark, there shall be no earnings band rate adjustment. If earnings are more than 250 basis points above or below the ROE benchmark, the company would make an earnings band rate adjustment as specified below:

Earnings variance from benchmark ROE	PacifiCorp rate adjustment
251 to 350 basis points higher (lower) than the ROE benchmark	Price decrease (increase) equal to one-quarter of the adjustment needed to reach 250 basis points
More than 350 basis points higher (lower) than the ROE benchmark	Sum of one-half of the price decrease (increase) needed to reach 350 basis points plus one-quarter of the additional price decrease (increase) needed to reach 250 basis points

The ROE benchmark shall be set initially at 10 percent, updated annually for each earnings review. The benchmark will be adjusted by the average of: (1) the change in interest rates, and (2) the change in electric utility industry dividend yields.

The average interest rate shall be equal to the arithmetic average of 5-,7-, and 10-year constant maturity U.S. Treasury rates obtained monthly over the earnings review period from Federal Reserve Statistical Release H. 15, corrected for the use with an average base rate. The dividend yield change shall be equal to the difference between: (a) the average electric utility sample dividend yield underlying the previous benchmark ROE; and (b) the average of dividend yields over the current earnings review period. The average dividend yield is equal to the arithmetic average of electric power common stock yields obtained monthly over the earnings review period from Moody's Public Utility. The initial interest rate shall be 5.8 percent[6]; the initial dividend yield shall be 6.58 percent.[7]

The company's capital structure shall be set at 46.3% long-term debt, 7.1% preferred stock, and 46.6% common equity, and will remain constant for the term of the AFOR. Costs of long-term debt and preferred stock would be updated annually consistent with the earnings review period.

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[6] The initial interest rate is an adjusted average of U.S. Treasury note rates for securities trading on November 12, 1997, as reported in the Federal Reserve statistical release. The rounded average of the 5-, 7-, and 10-year rates is 5.9 percent, which is corrected downwards to a rounded 5.8 percent for average rate base assumption.

[7] The initial dividend yield is the arithmetic average of electric power common stock yields as reported in the November 18, 1997, *Moody's Public Utility*.

6. Annual Earnings Review:

PacifiCorp shall provide an annual earnings report for the most recent prior calendar year by April 30 of each year, beginning in 1999 for the 1998 calendar year. The report will be similar in format and content to, and replace, the current semiannual reports, including actual results of operations and Type 1, Type 2, and at the company's option, Type 3 normalized adjustments. Only the Type 1 analysis will be used for determining the earned ROE for purposes of making any earnings band price adjustments. Type 1 adjustments include, but are not limited to, all adjustments applicable to a recorded period of the nature contained in the stipulated results adopted by Order No. 96-175. The analysis should include *pro forma* adjustments removing the effects of any performance penalties and rewards and any earnings band price adjustment in the review period.

PacifiCorp should also provide, for information purposes, separate allocated revenues, costs and rate base for the generation, transmission and distribution functions.

The earnings report shall be used to determine PacifiCorp's earnings as measured by return on equity (ROE). The results will be used to verify that the company's earnings are within the formalized earnings band, described above, and as the basis for earnings band price adjustments in the event that earnings fall outside the band. The reports also may be used in determining whether the AFOR plan should be extended an additional three years. There shall be an earnings review and potential adjustment on July 1, 2001, even if the plan is terminated or modified on June 30, 2001.

7. Adjustments for Major Events:

Changes to PacifiCorp's costs caused by "major events" outside the company's control shall be reflected in any annual price change. "Major events" are limited to changes in Federal/State/Local taxes, including the enactment of an energy-related tax.

PacifiCorp may pass through to customers the full impact of tax changes, other than energy-related taxes, that exceed an annual threshold of 1 percent of Oregon retail revenues (in either direction), subject to review by the Commission. For energy taxes, PacifiCorp will have the opportunity to demonstrate, in a separate proceeding, that it should recover costs of an energy tax outside any index-related change.

In the event that there is a significant tax change that qualifies as a major external event, an additional adjustment would be made to prices to pass through the tax impact. The adjustment would be made after applying the indexed price change and should have no impact on projected earnings. In subsequent years, the AFOR indexed price would be applied to the then-current total prices.

8. Rate Spread and Rate Design:

Until the Commission issues an order in the generic cost of service proceeding (UM 827), PacifiCorp shall use the same rate spread for AFOR price increases approved in Order No. 96-175. Price increases by customer class shall be capped so that no customer class will receive more than a 2 percent AFOR price increase on distribution in any one year. Under a rate spread where the 2 percent customer class price cap is applied, the balance of the price increase shall be carried forward as specified under Section 3. AFOR price decreases shall be allocated on an equal percentage basis to all customer classes prior to the Commission's decision in UM 827.

After the Commission issues an order in UM 827, PacifiCorp shall file a proposal to implement the Commission's findings before its next AFOR rate change, but no more than six months after the date of the UM 827 order.

For price increases, AFOR price design changes shall be applied as indicated in PPL/34 Griffith/10-11.

This rate spread and rate design shall apply to all AFOR-related rate changes except the system benefits charge (*See* Section 11, *infra*).

9. Service Quality Standards:

Eight performance measures for evaluating service quality, as well as revenue requirement deductions for poor performance, shall be included in the AFOR. The purpose of the performance measures will be to provide a mechanism to ensure service quality is maintained at current or improved levels subsequent to the implementation of the AFOR.

The service quality performance measures, set forth in Appendix D, shall be effective for a period of ten years, beginning in January 1998, and shall be in effect independent of the existence of any AFOR plan. Failure of PacifiCorp to abide by the service quality measure agreement shall be grounds for revocation and possible termination of the AFOR plan.

10. Renewable Resources:

The distribution-only AFOR shall include an incentive to acquire renewable resources at costs that are lower than were projected in PacifiCorp's 1995 least-cost plan (RAMPP-4) or any subsequently acknowledged least-cost plan in effect at the time the project begins commercial operation.

The incentive shall apply to wind, geothermal, and solar projects that begin construction after July 1, 1996, and whose levelized costs per kWh are at least 10 percent lower than the corresponding cost estimate in the applicable least-cost plan. The levelized life-cycle cost of the resource shall be based on the use of a 30-year contract.

A maximum of 50MW (PacifiCorp total system share) is eligible. The incentive rate would be equal to 50 percent of the difference between the least-cost plan estimate and the cost estimate of the project at the time it begins commercial operation. The rate would be applied to actual output for the first five years of operation.

Any revenue requirement change associated with the Foote Creek wind project, as well as any qualifying projects under the renewable resource incentive, shall be recovered in the system benefits charge.

11. <u>System Benefits Charge:</u>

The AFOR shall include a System Benefits Charge (SBC) on distribution services to recover all costs of Demand Side Management (DSM) programs and the incentives for the development of renewable resources. Existing Schedules 191 and 192 shall remain in effect for DSM activity undertaken through the end of 1996. Revenue requirement changes associated with qualifying renewable resources would also be recovered through the SBC.

The SBC shall collect DSM costs actually incurred by PacifiCorp. The SBC shall be established as soon as practical for 1997 DSM activity; subsequently, each April 30 (beginning in 1999) the company shall file to adjust the SBC on July 1 to (1) recover the cost of DSM activities in the previous calendar year and (2) true-up for any difference between the amounts targeted and actually collected in the SBC. PacifiCorp shall be required to demonstrate in its filing that its activities were consistent with the DSM targets in its least-cost plan.

The amount collected each year shall be spread to customer classes on an equal percentage basis and collected through an energy charge, with lighting schedules charged the average cents per kWh (the same rate spread as in existing Schedules 191 and 192.) The SBC shall be non-bypassable. Customers that choose generation services from alternate providers through direct access will continue to pay the SBC. The SBC for those customers shall be average cents per kWh charge of the “full service” customer class with comparable load characteristics.

12. Bond Ratings:

During the term of the AFOR, PacifiCorp shall maintain bond ratings for senior debt with Moody's and Standard & Poors (S&P) of at least Baa2 and BBB, respectively. If the company's bond ratings fall below these levels, either the company or the Commission may request reevaluation and possible termination of the AFOR plan.

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SERVICE QUALITY MEASURES

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Summary of Service Quality Performance Measures -- Table I

Code	Description	Measure Value Calculation	OBJECTIVE	Revenue Requirement Reduction *(see notes 1 and 2)*
C1	At Fault Customer Complaints	C1= "At Fault" Complaints/ total number of Company customers /1000	____complaints	Please see note #3
R1	Average Interruption Duration	R1 = 3-year weighted average of the SAIDI indices for the three most recent years	_____hours	Please see note #3
R2	Average Interruption Frequency	R2 = 3-year weighted average of the SAIFI indices for the three most recent years	______ occurrences	Please see note #3
R3	Average Momentary Interruption Frequency	R3 = 3-year weighted average of the MAIFI indices for the three most recent years	____events	Please see note #3
S1	Major Safety Violations	S1 = No. of Major Safety Violations	0.0 violations	$100,000 to $500,000 for each major safety violation cited by the Commission. (See page 12 to determine revenue requirement reduction amount.)
X1	Annual Review Vegetation Management	-Annual report from Company -Staff evaluations -Submittal to Commissioners	Company Goals	No specific revenue requirement reduction provisions, possible comm. orders. Inadequate safety in S-1.

(cont'd)

Service Quality Performance Measures Summary -- Table I (cont.)				
X2	Annual Review Basic I & M programs	-Annual report from Company -Staff evaluations -Submittal to Commissioners	Company Goals	No specific revenue requirement reduction provisions. Possible comm. orders. Inadequate safety in S-1.
X3	Annual Review Special Programs	-Annual report from Company -Staff evaluations -Submittal to Commissioners	Company Goals	Advisory only. Proactive preventative programs to enhance safety and reliability, research/trials.

Notes:

1. The Company would incur no revenue requirement reductions with proper system operation and maintenance (O&M). Revenue requirement reductions would be incurred, however, in the various areas shown above based upon the level of non-compliance with service/safety standards.

2. Any shortfalls in actual versus allowed expenditures for pertinent accounts during the term of the plan could be subject to customer refunds, if the Commission deems that the Company had not engaged in adequate operating practices to maintain safety and reasonable service quality. (See General Stipulations, paragraph F.3.)

3. For performance at or above ___ and below ___, the PUC may determine a revenue requirement reduction amount of up to $100,000 per year and/or order reasonable corrective actions and/or order a return of unspent O & M funds to customers.
   For performance at or above ___, the PUC may determine a revenue requirement reduction of up to $1,000,000 per year and/or order a return of unspent O & M funds to customers and/or make a determination that inadequate service is being provided in violation of ORS 757.020.

Summary of Service Quality Performance Measure – Table 2				
Ranges	**Normal Operating Range**		**Unacceptable Operating Range**	
			Revenue Requirement Reduction Range 1	**Revenue Requirement Reduction Range 2**
Financial Revenue Requirement Reductions			to $100,000.00 per year for each designated category	to $1,000,000.00 per year for each designated category
	None	None	possible return to customers of unspent O & M funds for related programs	possible return to customers of unspent O & M funds for related programs
Additional Commission Order Options			possible orders to perform corrective actions	possible orders to perform corrective actions
	None	None		other orders related to inadequate service as required by ORS 757.020
Performance lines	0.0	Objective Line (Performance Goal)	Revenue Requirement Reduction Threshold Line	Revenue Requirement Reduction Line 2

Note: Specific values are set for the performance lines for measures CI, RI, R2, R3 and S1. The S1 revenue requirement reduction design is different than Table 2. The Commission reserves the right to pursue other formal actions for service not deemed adequate pursuant to the standards set forth in ORS 757.020.

SERVICE QUALITY MEASURES

A. DEFINITIONS:

1. "Company" shall mean Pacific Power and Light Company.

2. "Commission" or "PUC" shall mean Public Utility Commission of Oregon. "Staff" shall mean PUC Staff.

3. "Service Quality" or "SQ" means those aspects of energy delivery and customer service including, but not limited to, safety, reliability, operations, tariff compliance and customer relations.

4. Performance below the revenue requirement reduction threshold line is the maximum measure value that is considered acceptable.

5. "OAR" shall mean Oregon Administrative Rule.

6. Abbreviations used herein are defined as follows:

   ANSI......American National Standards Institute
   IEEE.....…Institute of Electrical and Electronic Engineers
   NESC..…National Electrical Safety Code
   O&M......Operations and Maintenance
   T&D.......Transmission and Distribution
   I & M......Inspection and maintenance

B. PURPOSE:

The purpose of these performance measures is to provide a mechanism to ensure service quality is maintained at current or improved levels subsequent to implementation of an alternate form of regulation (AFOR) for the Company.

C. PERFORMANCE MEASURES:

The eight (8) performance measures for evaluating service quality on an annual basis are as follows:

1. C1 At Fault Customer Complaint Frequency
2. R1 Average Customer Interruption Duration
3. R2 Average Customer Interruption Frequency
4. R3 Average Momentary Interruption Frequency
5. S1 Major PUC Safety Violation Frequency
6. X1 Vegetation Management Programs and Service Personnel Count
7. X2 Basic I & M Program

8. X3 Special Programs

These performance measures shall be based on Oregon customers only. (See specific measure description for calculations and criteria associated with each measure.)

D. COMPLIANCE:

For any specific circumstance, the attached measures should not be used for determining Company noncompliance with PUC regulations. These measures and associated agreements do not relieve the Company of its legal responsibilities to comply with PUC regulations or orders. Moreover, revenue requirement reduction actions associated with these measures do not preclude the Commission from pursuing compliance actions or civil revenue requirement reductions as allowed by ORS chapters 756 and 757.

E. RECORDS AND REPORTS:

1. The Company and Staff shall meet on or before November 15 of each year to determine reasonable levels for setting the Objective Line, Revenue Requirement Reduction Threshold Line and Revenue Requirement Reduction Line 2 for measures C1, R1, R2 and R3 for the following year. If an agreement is reached, a joint report shall go to the Commission recommending these levels. If the Company and Staff do not agree, separate reports with recommended levels will go to the commission for their determination of levels for the coming year. The report(s) shall be submitted to the Commission on or before December 15.

2. The Company shall submit a report annually which documents each measure value and revenue requirement reduction, if any, for the previous calendar year. The annual report shall be completed on forms and computerized spreadsheets prepared by the Company and approved by Staff. The report, along with supporting data and calculations on computer disks, shall be submitted to Staff annually on or before May 1 of each year for the preceding calendar year. Each annual report shall explain historical and anticipated trends and events that have affected or will affect the measure in the future.

3. The annual report shall address any Company procedural changes that affected the results of the measures or revenue requirement reductions during the preceding year.

4. The Company shall maintain the data, district reports, and field records that document customer interruptions for a minimum of ten years.

5. The data and calculations to develop these measures shall be audited to assure accuracy by the Company’s designated reliability engineer.

6. The Company shall also provide a separate written report for a major event that significantly impacts any of these measures. The written report shall comply with OAR 860-023-0160

requirements. A major event, as defined in OAR 860-023-0080, means a catastrophic event that:

a. Exceeds the design limits of the electrical power system;
b. Causes extensive damage to the electric power system; and
c. Results in a simultaneous sustained interruption to more than 10 percent of the customers in an operating area.

The report shall be submitted to PUC Staff within 20 days of the occurrence of the major event. These reports shall state whether or not the Company intends to request exclusion by the Commission from the reliability measures (R1, R2 and R3) and shall provide the information necessary to determine if the major event meets the exclusion requirements as defined above. The exclusion can be for the entire service area in Oregon or can be limited to one or more specified operational areas (divisions).

F. REVENUE REQUIREMENT REDUCTIONS:

1. Unless otherwise specified herein, the Company may incur a revenue requirement reduction for substandard performance associated with each measure. The revenue requirement reduction shall be determined using the criteria specified for each performance measure. The Company shall pay such revenue requirement reductions through rate-reductions or other methods as deemed appropriate by the Commission.

2. The revenue requirement reductions may be waived, capped, or otherwise adjusted by the Commission under extenuating circumstances clearly beyond the Company's control. Special allowances may be considered by the Commission provided that the Company is not found to be in violation of relevant PUC statutes and/or acceptable utility practice.

3. Utility operating and maintenance expenditures in certain key areas have been identified and will be submitted by the Company for PUC review annually (see key expenditure areas below). Any shortfalls in actual versus historical levels of expenditures at a time of satisfactory program performance during the term of the plan would be subject to refund with interest at the Company's authorized rate of return, if the Commission deemed that the Company had not engaged in adequate operating practices to maintain safety and reasonable service quality. This provision is limited to key areas related to the respective service quality measure involved and would apply only if any revenue requirement reduction threshold level (C1, R1, R2, or R3) is exceeded, or if in the Commission's judgment, too many S1 safety violations occur during the term of the plan.

   The key expenditure areas related to each performance measure and subject to this provision are as follows:

Measure	Expenditure Area

C1	Customer Service
R1, R2, R3 and S1	Specific program areas related to T&D operations, maintenance, and safety, including: • Vegetation Management (XI); • System inspections, maintenance, and repairs; and • Pole/structural inspections, replacement and reinforcement.

4. For safety violations, the Commission may also pursue actions under ORS 756.990.

5. Disposition of any revenue requirement reduction assessments under agreement shall be at the Commission's discretion and may include, but shall not be limited to, customer refunds or rate reductions and expenditures on beneficial programs.

G. SPECIAL PROVISIONS:

1. The Commission may direct Staff, the utility or a qualified consultant, to conduct special investigations including inspections, testing, audits, and other checks that the Commission deems necessary to assure that the measures and supporting data accurately reflect customer experiences and trends. The cost for such investigations and audits will be borne by the Company. In the event that such investigations reveal noncompliance with the provisions of this document, the Company shall make payment for the revenue requirement reduction variances found by the investigations plus interest at the Company's authorized rate of return.

2. The Commission, after an opportunity for Company, Staff, and public comment, may modify any service quality measure included herein. Modifications could involve, but are not limited to, objective lines, revenue requirement reduction lines, revenue requirement reductions, calculation methods, reporting requirements, or other matters included within this stipulation.

H. TERM:

The term of this agreement is 10 years, beginning January 1, 1998.

I. SPECIFIC MEASURE AGREEMENTS:

The specific agreements for the C1, R1, R2, R3, S1, X1, X2, and X3 are described as follows:

Measure C1 -- Customer "At Fault" Complaint Frequency

1. Description: The C1 measure is the annual total number of “at fault” complaints per 1,000 customers received by the PUC related to Company tariffs, policies, standards, and practices involving customer service issues.

2. Definition: An “at fault” complaint is a complaint designated a “COMPLAINT, COMPANY AT FAULT” consistent with current PUC Consumer Service Division practices. “At fault” complaints are identified as follows:

Code	Customer Service Violation Description
“R”	A rule violation involves a violation of an Oregon Statute (ORS) or an Oregon Administrative Rule (OAR).

“T” A tariff violation involves a violation of the Company’s approved tariffs and operating rules as filed with and approved by the PUC.

“C” A customer service violation involves inappropriate and unacceptable customer treatment exemplified by, but not limited to, the following:

- Missed service/repair commitments without prior consumer notification;
- Unreasonable service or repair delays;
- Unreasonable facility installation delays;
- Incorrect or incomplete information provided to consumers, resulting in customer inconvenience or loss;
- Unreasonable inaccessibility of the Company to customers;
- Unreasonable delay in response to consumer inquiry.

Differences and disagreements of “at fault” designations for specific complaints will be submitted for informal supervisory review and if unresolved, may be appealed through existing formal processes for determination by the Commission.

3. Data Source: PUC Consumer Services Division records and reports.

4. Measure Calculation: The C1 measure is equal to the total number of Company “at fault” complaints handled by the PUC during the year, divided by the total average number of Company Oregon customers divided by 1,000. The number of customers shall be based on a year-end total of the Company’s Oregon customers.

5. Objective: A performance goal cooperatively set by the Company and PUC Staff.

6. Revenue Requirement Reduction Threshold: A specific number of “at fault” complaints per 1,000 customers set annually.

7. Revenue Requirement Reduction Line 2: A specific number of “at fault” complaints per 1,000 customers set annually.

8. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the set number of “at fault” complaints per 1,000 customers. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options. (See Summary Table 2).

9. PUC Staff Responsibilities: PUC Staff shall make available the annual measure value mentioned in the data source (item 3 above) by May 1 of the following year.

Measure R1 -- Average Customer Interruption Duration

1. Description: The R1 measure is the weighted average of the last three years' system average interruption duration indices (SAIDI). The SAIDI is the outage time, in hours, that an average customer experiences during the year.

2. Data Source: Company's reliability records, data, and certified reports.

3. Measure Calculation: The R1 measure is a three-year weighted average of the SAIDI reliability indices experienced by the Company's Oregon customers. The weighted average is calculated by adding together the target calendar year at a 50 percent weighting factor, the preceding year at a 30 percent factor, and the second preceding year at a 20 percent factor. The SAIDI is defined and calculated per IEEE and EEI standards (*see* IEEE draft standard P1366, dated October 18, 1995).

4. Objective Line: A goal cooperatively set by the Company and PUC Staff.

5. Revenue Requirement Reduction Threshold: A specific number of hours of outage for the average customer set annually.

6. Revenue Requirement Reduction Line 2: A specific number of hours of outage for the average customer set annually.

7. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the Revenue Requirement Reduction lines. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options (see Summary Table 2).

8. Company Responsibilities: Company shall furnish an annual R1 measure value mentioned in data source (item 2 above) by May 1 of the following year.

MEASURE R2 -- AVERAGE CUSTOMER INTERRUPTION FREQUENCY

1. Description: The R2 measure is the weighted average of the last three years' system average interruption frequency indices (SAIFI). The SAIFI index is the number of extended outages that an average customer experiences during the year. Extended outages are greater than 5 minutes in length. This measure excludes momentary interruptions caused by automatic substation and line breaker operations.

2. Data Source: Company records, data, and certified reports.

3. Measure Calculation: The R2 measure is a three-year weighted average of the SAIFI reliability indices experienced by the Company's Oregon customers. The weighted average is calculated by adding together the target calendar year at a 50 percent weighting factor, the preceding year at a 30 percent factor, and the second preceding year at a 20 percent factor. The SAIFI is defined and calculated per IEEE and EEI standards. (*See* IEEE draft standard P1366, dated October 18, 1995.)

4. Objective Line: A goal cooperatively set by the Company and PUC Staff.

5. Revenue Requirement Reduction Threshold: A specific number of interruptions for the average Oregon customer set annually.

6. Revenue Requirement Reduction Line 2: A specific number of hours for the average customer set annually.

7. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the set number of interruptions. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options (see Summary Table 2).

7. Company Responsibilities: Company shall furnish annual R2 measure mentioned in data source (item 2 above) by May 1 of the following year.

MEASURE R3 -- AVERAGE CUSTOMER MOMENTARY INTERRUPTION FREQUENCY

1. Description: The R3 measure is the weighted average of the last three years momentary interruption frequency indices ($MAIFI_E$). The $MAIFI_E$ index is the number of momentary interruptions that an average customer experiences during the year.

2. Data Source: Company records, data, and reports. This measure shall be implemented as detailed below:

a. 1998 - A sample-based estimate and actual data of this measure will be part of the Company report.
b. 1999 - Actual data is collected for this measure with trial objective and revenue requirement reduction lines set.
c. 2000 - full implementation.

3. Measure Calculation: The R3 measure is a three-year weighted average of the $MAIFI_E$ reliability indices experienced by the Company's Oregon customers. This average is calculated by adding together the target year at a 50 percent weighting factor, the preceding year at a 30 percent factor, and the second preceding year at a 20 percent factor. The $MAIFI_E$ is defined and calculated per IEEE draft standard P1366, dated October 18, 1995. This index excludes interruptions that are greater than 5 minutes in length, and excludes momentary interruptions that are included in a single relay sequence that results in breaker lockout (extended outage).

4. Objective Line: A goal cooperatively set by the Company and PUC Staff.

5. Revenue Requirement Reduction Threshold: A specific number of interruptions for the average customer set annually.

6. Revenue Requirement Reduction Line 2: A specific number of interruptions for the average Oregon customer set annually.

7. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the revenue requirement reduction threshold. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options. (See Summary Table 2).

8. Company Responsibilities: Company shall furnish annual R3 measure value, as detailed in 2 and 3 above, by May 1 of the following year.

MEASURE S1 -- MAJOR PUC SAFETY VIOLATION PERFORMANCE MEASURE

1. Description: The S1 measure indicates the number of major safety violations cited by the Commission that were in effect during the year. The revenue requirement reductions associated with this measure are to acknowledge the fact that customers have paid for adequate maintenance in their rates and that a major safety violation is a reflection that the Company should recompense customers in some manner for the safety situation cited.

2. Definition: A "major safety violation" involves a pattern of serious unsafe conditions or circumstances that puts the public, customers, or lineworkers at serious risk of injury, and involves noncompliance with the National Electrical Safety Code (NESC) rules numbers 121, 214, and 313. The three rules address the Company's responsibilities to inspect, test, and maintain their power-line facilities so that they are kept in a safe condition. Also, a "major safety violation" could involve any failure by the Company to comply with OAR 860-028-0005 in reporting personal injury incidents.

   Should PUC Staff determine that the Company has committed a major safety violation, Staff will present its recommendation to the Commission. Should the Commission authorize issuance of a citation alleging a major safety violation, the Company will be afforded an opportunity to present evidence at hearing under the provisions of ORS 756.515 contesting the alleged violation or violations and evidence of any mitigating factors that the Company contends should be considered by the Commission in determining whether to assess the full revenue requirement reduction assessment or a lower amount. A major safety violation must be determined to have occurred by Commission order.

3. Data Source: Commission records.

4. Revenue Requirement Reduction Threshold: 0.0 major safety violations.

5. Revenue Requirement Reduction Calculation: For each major safety violation cited by the Commission the following will apply:

   a. If the Company can demonstrate, to the Commission's satisfaction, that the major safety violation cited was corrected within 14 days of receipt of the proposed citation by PUC Staff, and if the Commission deems that a major safety violation has occurred, the Company shall set aside the amount to be determined by the Commission up to $0.1 million in revenues it has received from its customers for disposition by the Commission.

   b. If the Company cannot demonstrate, to the Commission's satisfaction, that the major safety violation cited was corrected within 14 days of receipt of the proposed citation by PUC Staff, and if the Commission deems that a major safety violation has occurred, the Company shall set aside the amount to be determined by the Commission up to $0.5 million in revenues it has received from its customers for disposition by the Commission.

c. The maximum assessment for any one major safety violation is $0.5 million.

d. This measure does not have a maximum revenue requirement reduction amount.

MEASURE X1 -- VEGETATION MANAGEMENT PROGRAM AND SERVICE PERSONNEL COUNT (OREGON)

1. Description: The Vegetation Management Program is a Basic Maintenance Program that is set apart from the other I & M programs due to the crucial effect trees can have on system safety and reliability. Trees and other vegetation are trimmed or removed to provide line clearance and prevent system damage. The service personnel count is a valuable early warning indicator to alert Staff of the Company's ability to adequately maintain it's system.

2. Required Interval: Trimming is accomplished on a 3.5-year cycle. 29% of the system is trimmed annually with no individual year falling below 25% of the system. Note: Approximately 25% of the system is trimmed on a 4-year cycle due to localized climatological conditions and associated slower growing tree species. All distribution feeders and grids will be inspected within one year before the end of the scheduled cycle. Individual trees which may cause problems during storms are then identified and corrected before year end.

3. Company Quality Control: Not less than 10% of recently completed tree trimming is inspected on a continuous basis to ensure compliance to the Program Plan and achievement of adequate clearance.

4. Program Expenditures: Annual budget with actual versus planned expenditures. Information will include total budget and the underlying components of routine maintenance trimming; hot-spot trimming; and off-map trimming such as customer requests, minor storm work, capital construction trimming; and administration.

   Budgeted Personnel Information (Oregon) for the following positions (FTEs): Company Foresters; Average number of Contract Tree Crews (including total FTEs); Customer Service Associates; Engineering Services (field engineers and estimators); Field Services (line crews overhead and underground, servicemen, supervisors, contract crews (specify)); Substation employees (crews, technicians, inspectors, supervisors (specify)) Metering employees (shop, testers, supervisors (specify)).

5. Data Source: Company records, data and reports. Staff data review and field review.

6. Measure Calculation: There is no individual measure calculation. An annual report with Staff comments and recommendations will be submitted to the commission each spring (May 1) for their review and any action deemed appropriate. Program problems will normally result in NESC violations being cited by PUC Staff with extensive problems resulting in a major PUC Safety Violation (Measure S1).

MEASURE X2 -- BASIC INSPECTION AND MAINTENANCE PROGRAMS

I. INSPECTION AND REPAIRS

A. Pole and Overhead Facilities

1. Description: Inspection and treatment of all Company-owned distribution and transmission poles and overhead distribution facilities. All Company-owned poles are intrusively inspected for strength. Distribution equipment attached to any pole is inspected, repaired, or replaced to ensure the electrical system remains in good working order and meets the National Electric Safety Code (NESC). The first cycle is completed in 1998. The second cycle begins January 1999.

2. Required Interval: 10-year cycle, 10% annually with no individual year falling below 8.5%. Repairs or replacement completed promptly. Repairs are designated “A” (immediate hazard), requiring correction within 30 days, or “B,” requiring correction within approximately one year but in no case extending beyond the calendar year following the year of discovery.

3. Company Quality Control: Inspection by appropriate random sample to ensure accuracy of inspection. Minimum 5% of facility points that have been detail inspected are inspected as needed to ensure NESC compliance during each year.

4. Program Expenditures: Annual budget figures to include: (a) Pole and Overhead Facilities Inspection and Pole Treatment; and (b) Repair and Replacement of Facilities

B. Safety Survey

1. Description: A drive-by survey of the distribution system. The survey is designed to spot incidental damage to the system (such as damage from stormy weather) that neither caused an outage nor was reported.

2. Required Interval: 2-year cycle with 50% of the system driven yearly.

3. Company Quality Control: Random sample by supervisory personnel or their designees to ensure uniform results and adherence to the plan and accuracy of survey.

4. Program Expenditures: Planned and actual annual budget.

C. Underground Facilities:

1. Description: Inspection program includes a thorough visual inspection of underground vaults, pad-mount transformers, switches, and an infrared inspection of all accessible terminals and splices. The first cycle starts in 1998.

2. Required Interval: 4-year cycle, 25% of the system annually with no individual year falling below 20% of the system.

3. Company Quality Control: Inspection by appropriate random sample to ensure accuracy of inspection.

4. Program Expenditures: Annual budget figures to include: (a) Facilities Inspection, and (b) Repair and Replacement of Facilities.

D. Substation Safety

1. Description: Inspection of each substation on the Transmission and Distribution system. The survey is designed to spot vulnerability of intrusion of the enclosure fences, NESC compliance, incidental damage to substation equipment, and the operational condition of the system.

2. Required Interval: 1-month cycle for all substations' security inspections and 3-month cycle for operational inspections.

3. Company Quality Control: Random sample by supervisory personnel or designee to ensure accuracy of survey.

E. Marina Inspection Program

1. Description: Inspection of Company facilities at every marina in Oregon service area.

2. Required Interval: Annually.

3. Company Quality Control: A random sample is reinspected by the supervisor or designee to ensure accuracy of inspection and NESC code compliance.

F. Major Equipment Maintenance

1. Line Equipment:

a. Pole Top Reclosers and Sectionalizer Program: Inspection of oil-filled reclosers, vacuum reclosers and sectionalizers.

(i) Required Interval: The equipment is inspected every two years.

(ii) Company Quality Control: The program is controlled by an operations manager who ensures implementation and coordination.

b. Pole Top Voltage Regulators Program: Inspection of these devices.

(i) Required Interval: Voltage regulators are inspected every two years.

(ii) Company Quality Control: The program is controlled by an operations manager who ensures implementation and coordination.

c. Switch Program: Inspecting all Company-owned pole-mounted distribution switches.

(i) Required Interval: 5-year cycle with the first cycle starting in 1998.

(ii) Company Quality Control: The program is controlled by an operations manager who ensures implementation and coordination.

2. Substation Equipment

a. Batteries: Batteries are maintained to assure adequate voltage level is present to operate breakers, protective relaying and motor operators during adverse weather conditions and emergencies to assure safety and system reliability.

(i) Required Interval: Inspected on a 3-month cycle. Company will annually provide the PUC Staff the next year's testing objectives and comparison of previous year's objectives to the actuals.

(ii) Company Quality Control: Post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

b. Capacitor Banks: The 3-month operational inspection includes a visual inspection to identify damaged or failing capacitors.

c. Breakers: Breakers must operate upon demand to protect the public in emergencies or fault conditions to assure safety and system reliability and allow efficient operation of the system.

   (i) Required Interval: Company will annually provide the PUC Staff the next year's objectives and comparison of the previous year's objectives to the actuals.

   (ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or their designee to assure adherence to the objective which result from the Company's Substation Maintenance Standards.

d. Disconnect Switches & Connectors: Maintained to assure ability to safely operate the system and provide safe working clearances.

   (i) Required Interval: Annual Infra-Red inspections performed on selected devices to identify any potential problem for corrective maintenance.

   (ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or their designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

e. Load Tap Changers (LTCs): Maintain system voltages within a desired operating band to assure reliable service and customer equipment performance.

   (i) Required Interval: Company will provide the PUC Staff the next year's objectives and comparison of previous year's objectives to the actuals.

   (ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

f. Regulators: Maintain system voltages within a desired operating band to assure reliable service and customer equipment performance.

(i) Required Interval: Company will provide the PUC Staff the next year's objectives and comparison of previous year's objectives to the actuals

(ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives that result from the Company's Substation Maintenance Standards.

g. Transformers: Transformers provide the means to most efficiently and cost effectively move electrical energy from source to point of use. They are maintained to assure the most capital intensive substation equipment's life is maximized while assuring system reliability.

(i) Required Interval: Company will provide the PUC Staff the next year's objectives and comparison of previous year's objectives to the actuals

(ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

h. Protective Relaying: Relays are maintained to assure adequate protective actions occur to trip faulted equipment and lines in abnormal conditions and emergencies to assure safety and system reliability.

(i) Required Interval: Company will provide the PUC Staff the next year's objectives and comparison of previous year's objectives to the actuals

(ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

3. Meters

Company shall comply with meter accuracy requirements and testing schedules required by OAR 860-023-0015 and approved by the Commission. Additionally, Company shall provide an annual report and presentation to the PUC Staff by May 1 about the previous year's metering program accomplishments and issues, meter accuracy trends, failed meter groups and types, meter repairs and retirements, program modifications, and new applied technologies.

All electric meters and associated equipment and utilization shall comply with applicable requirements of the National Electrical Safety Code (NESC), National Electric Code (NEC), American National Standards Institute (ANSI), and other standards adopted and published by the Commission. Additionally such equipment shall comply with the Oregon Electric Service Requirements Manual (published jointly by PacifiCorp and Portland General Electric), the Electric Utility Service Equipment Requirements Committee (EUSERC), and the Company's Meter Standards Manual.

a. Company Quality Control: Random sample by supervisory personnel or their designee to ensure uniform results and adherence to the plan and accuracy of data.

II. STANDARDS AND STANDARD PRACTICES

A. Company Standards including standard practices are necessary to ensure compliance with NESC, NEC, Company tariffs, PUC laws, and good engineering practice. Annual reviews and quality control of the below standards are necessary to ensure that they remain current and are being uniformly implemented in the field:

Electric Service Requirements

Joint-Use Standards

Construction Standards

Design Standards

Operation and Maintenance Standard Practices

Quality Control Program

B. Required Interval: Annual and other needed reviews of the above standards by Company Standards Department to resolve standards issues associated with customer complaints, joint-use conflicts, PUC enforcement actions, code and regulation changes, etc.

C. Company Quality Control: Annual review by Company standards engineer to ensure that the above standards are updated. Random sample by standards personnel to ensure uniform results and adherence with the standards in the field.

MEASURE X3 -- SPECIAL PROGRAMS

1. Special Programs address specific issues which may effect T&D operation, maintenance or safety. They normally operate for a specific period of time, accomplish their intended purpose, and are terminated upon completion. Information discovered in the program may result in the establishment of specific, routine, ongoing programs.

2. These special programs will be reviewed annually and reported on to PUC Staff. The list of special programs is expected to change annually.

   -Underground Cable Replacement

   -Squirrel Guards

   -Pilot Programs

   -Overhead Notification

   -National Joint Utility Notification System

   -Powerline Related, Forest Fire Prevention Consortium

REPORTING OF X1, X2, AND X3 PROGRAMS

A yearly Maintenance Program Review Meeting will be held by May 1. Applicable information on each program's accomplishments for the year and plans for the next year will be presented to and discussed with PUC Staff. A written report, both paper copy and on compatible electronic format, will follow this meeting and be presented to PUC Staff that same day. This report will summarize all information presented at the yearly meeting. Quarterly updates are provided for the X1 measure.