2. Overview of Allocations

A. Introduction.

In approving the 1989 merger that created PacifiCorp's current six-state service territory, each commission recognized that a significant economic benefit would accrue to customers because the seasonal usage profile of the combined system better matched the characteristics of the Company's generating resource portfolio. Retail loads in the western part of the Company's system are highest in the winter and retail loads in the eastern part of the Company's system are highest in the summer creating an opportunity for cost sharing benefits from the Company's primarily baseload units.

Realization of these potential benefits relied on working together. The Company and the staff's of PacifiCorp's state regulatory commissions have committed significant resources to the ongoing development of a universally accepted cost-allocation methodology for a vertically-integrated utility. Over time, consensus has broken down on issues unrelated to industry restructuring. Since 1996, the PacifiCorp Interjurisdictional Taskforce on Allocations (PITA) has also recognized that industry restructuring initiatives would present significant challenges to the prevailing cost-allocation methodology. No agreement on an appropriate remedy has been reached.

This section provides an overview of the cost allocation approaches and the related complexities. In recognition of the importance of this issue to the Resource Plan, PacifiCorp modeled three variations of cost allocation: Base Case (dynamic Modified Accord), Fixed Modified Accord and Fair Share. The details of these allocation methods are discussed in Sections 7 and 8.

B. Overview.

PacifiCorp is a multi-state electric company that serves customers in California, Oregon, Washington, Idaho, Utah and Wyoming. OAR 860-038-0080 specifically directs a multi-state utility to address inter-jurisdictional allocation issues in its Resource Plan. The Company's Resource Plan must include a "fixed Oregon-allocated generating resource share." It must be based upon the "forecasted allocation of each generating resource" using traditional, Commission recognized allocation methods.

Traditionally, PacifiCorp has based its interstate allocation methods on some measure of relative cost causation. Even using this generally accepted concept, PacifiCorp has experienced difficulty getting all the states to agree on the same method for handling each cost item.

The PacifiCorp-Utah Power and Light Company merger in 1989 complicated PacifiCorp's interstate allocation process because Utah Power had higher costs and rates than Pacific Power. If Utah Power's costs were simply "rolled-in", Pacific

Power's rates would have increased while Utah Power's decreased. The unfairness of this result would have led other states' commissions to reject the merger, leaving no benefits for any customers.

To address this issue, PacifiCorp and its state regulators ultimately devised the "Modified Accord" allocation method to ensure that customers in all states would see merger benefits and no rates would increase because of the merger. Under this system, Utah Power's rates were higher and Pacific Power's were lower than they would have been under the "rolled-in" approach. Over time, because of pre-merger plant depreciation, the Modified Accord method moves toward, but not all the way to the Rolled-in approach. But across the board, all rates were lower than they would have been without the merger, resulting in benefits for all customers.

As long as all states served by PacifiCorp followed the same allocation method, the Company had the opportunity to recover all of its prudently incurred costs. Over time, this consistency has diminished. In 1997, Utah unilaterally switched to the "rolled-in" allocation method, and Idaho is currently phasing it in, stating that it intends to implement it during the next rate case. The other jurisdictions remain on Modified Accord. As a result, PacifiCorp no longer has the opportunity to recover all of the costs it prudently incurs to serve its customers' loads. In 1999, this discrepancy in allocation methods resulted in an allocation gap of about $55 million of unrecoverable revenue requirement, over $20 million of which is related to generation resources. The situation is obviously a serious problem for PacifiCorp and its regulators that would need to be addressed independent of SB 1149. As recognized in the Resource Plan objectives outlined in Section 1, the potential exacerbation of this situation as a result of SB 1149, is untenable.

C. Resource Plan Allocation Challenges.

The Resource Plan process poses a number of new allocation-related challenges. Three are of particular significance. First, as indicated, fixed shares of PacifiCorp's specific generating resources are not allocated to the various state jurisdictions under current practices. PacifiCorp has a single generating system that is dispatched on an optimal basis for the benefit of all of its customers. The fixed costs of that single system have been allocated based upon each state's relative contribution to system peak demand and relative energy consumption and the variable costs have been allocated based upon each state's relative energy consumption as these measures vary year-to-year. The expectation in the Resource Plan rule that a portion of the Company's generating resources be "released to the competitive market" cannot be achieved in the context of the current system of inter-jurisdictional cost allocations because, among other reasons, the current system assumes load-driven dynamic changes in cost allocations whereas a permanent "release" to the market assumes a fixed inter-jurisdictional dedication of resources.

Second, the Resource Plan rule also contemplates that PacifiCorp's cost-of-service rates will be based upon the cost of those generating resources permanently dedicated to serving those customers as reflected in the Resource Plan. This too is contrary to past practice, where cost-of-service rates were based upon an allocation of the costs of operating PacifiCorp's entire system. No meaningful cost-of-service rate can be derived from a relatively small subset of the Company's generating resources because such a subset does not and will not operate independent from the whole.

For example, the capacity of a "slice" of PacifiCorp's generating resources corresponding to the percentage of the Company's generation costs that have historically been supported by Oregon cost-of-service customers is not large enough to cover the peak loads of Oregon cost-of-service customers. This is because in winter months, Oregon draws on generating capacity that is supported by other states and during summer months, generating capacity supported by Oregon is available to support summer-peaking states. Additionally, for reasons such as this, the apparent average cost of operating the entire system, absent the portion of the system allocated to Oregon, will be different (and likely higher) than the actual average cost of operating the entire system. That is to say, an inappropriate balkanization of PacifiCorp's power supply assets could result in an increase in cost of service in some, if not all, of the Company's retail jurisdictions.

Third, the Resource Plan rules contemplate that to the extent Oregon's cost-of-service customers "outgrow" the resources allocated to them in the Resource Plan, additional resources acquired to serve them will not be included in the Company's Oregon rate base and that such incremental requirements will be served at a market price. This is contrary to the past practice of assuming that all new rate base additions are constructed to serve the entire system and allocated accordingly.

D. Summary.

In summary, the allocation challenges presented by the Resource Plan are significant. The process requires PacifiCorp to: (1) allocate generation resources to Oregon; (2) deal with the consequences of permanently fixing an allocated share for one state; (3) allocate these resources fairly among Oregon's customer groups; and (4) achieve support for the Resource Plan's decisions on these issues from each of its six state regulatory commissions.