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LOAD GROWTH ISSUES

I. Statement Of Issue and Conclusions of Analysis

A. Statement of the Issue

System costs change for a variety of reasons, among which is load growth. Current integrated-system allocation methods apportion to a growing jurisdiction both a share of the net cost caused by its load growth and a larger share of all other system costs. As part of the integrated system, other jurisdictions will be allocated a share of the cost changes occasioned by another's load growth and a correspondingly smaller share of all other system costs.

The following questions are key to an examination of the relative cost effects of load growth among states: 1) Does a faster growing jurisdiction impose or shift costs to slower growing jurisdictions; 2) is any such shift measurable, material, and significant; 3) how and to what extent do alternative allocation methods distribute the cost of load growth among jurisdictions with varying rates of growth; 4) does one allocation method appear to do a better job at providing reasonable results than another and why; and 5) can the importance of any such shift be reasonably understood at points in time or as part of a more complex continuity through time?

An allocation method should be robust under a broad range of future conditions.

The examination of load growth in this paper is limited. The quantitative portion of the analysis is of one set of future conditions only: a state, primarily Utah, with higher growth relative to the other states for the entire period examined and incremental cost close to or higher than average cost. None of the input assumptions have been varied and examined in a systematic way. Nonetheless, the examination undertaken is a useful exercise for revealing the consequences of a high-end range of adverse effects. If a method can adequately distribute the cost of load growth assuming this future, then we can gain comfort that the method will perform reasonably well under actual conditions.

PacifiCorp is a fully integrated electric utility system. Accordingly, we place the analysis of cost burdens in the larger context of known historical changes and such system integration advantages as load diversity, planning, organizational and operational efficiencies, and mitigation of risk and uncertainty. Our analysis is also subject to available quantitative studies that are based on one Company forecast of load growth[1] and on a limited set of assumptions about three other primary cost drivers: resources, fuel prices, and wholesale electric market prices. With this as guidance, we report the following conclusions of our analysis.

B. Conclusions of the Analysis

1. The total increase in revenue requirement borne by the more rapidly growing

[1] The 2003 load forecast may either reflect or amplify the current pattern of jurisdictional rates of relative growth.

jurisdiction generally covers the incremental costs associated with the more rapid load growth. In all of the cases where Utah is modeled as the fastest growing jurisdiction, it bears more than 80 percent of the incremental costs over time.

2. Under all quantitative studies of the cost impacts of a given jurisdiction's more rapid growth, the Rolled-in allocation method reasonably and consistently apportions the incremental costs of growth both to the faster growing and remaining states and does so under the variation in assumptions about cost drivers and under high-risk assumptions about the future. The cost of sustained harm to slower growing states that is actually experienced may be small enough that it can be absorbed when and if it occurs, like the Montana load loss.

3. Further study and monitoring of conditions that could produce sustained and significant harm to slower growing jurisdictions could be undertaken.

4. Other allocation methods studied include adjustments to the Rolled-in allocation method. While some of these methods also produce reasonable results for directing the cost of load growth to the growing state, they do not always do so consistently and also produce results that are unreasonably high or low for one or more of PacifiCorp's jurisdictions. In the quest to define a cost allocation method that removes all load growth cost risk to slower growing states, careful attention is required to ensure against

unintended consequences.

5. Regardless of a method's performance in allocating load growth costs, a complete evaluation of candidate allocation methods should proceed based on a set of evaluation criteria more encompassing than the single dimension of load growth.[2]

6. An effective integrated resource plan (IRP) minimizes the adverse effect of one state's load growth on other states. Effective IRP and resource acquisition should be a high priority for the Company and regulators.

[2] See the July 11, 2003 memo from Utah Parties to MSP participants for suggested evaluation criteria.

7. A review of history informs us that relative load growth rates and the conditions that define the cost effects of growth change significantly and in unexpected ways.[3] Whether load growth by itself is harmful or beneficial depends upon local and regional loads and resources, resulting market and fuel prices, and the relationship between incremental and average costs. These, history has shown, are cyclical in nature.

8. As costs of growth are apportioned to jurisdictions, these must be considered in light of the cost advantages of long-term participation in an integrated system, some of which have not been quantified. As a general statement, the larger number of options made possible by a diverse, integrated system will produce lower-cost service for all ratepayers in the long run. As adjustments to any allocation method are proposed, care will need to be taken to ensure that other integration advantages are not compromised in the effort to control the adverse potential effects of one aspect of integration. Examples of system integration advantages include:

(a) The risks of fuel and market price changes, of thermal outages, and of changes in jurisdictional loads are reduced for each jurisdiction because they are diffused across all

[3] Early after the merger in 1989, load growth lowered cost for all jurisdictions because the system and the region were in resource surplus and incremental costs were less than average costs. The system surplus was over time absorbed by load growth, a more advantageous alternative than sales in an unfavorable market. More recently, the circumstances have been the opposite.

jurisdictions. The larger integrated system provides greater flexibility to deal with uncertain future events, including changes in national and regional policies, than would any smaller configuration of the utility.

(b) Peak load diversity, the difference between system-coincident and non-coincident seasonal peak loads, results in lower capacity cost, and is a hedge against the cost consequences to a jurisdiction of year-to-year variations in its own load. For example, Oregon saved 432 MW in the winter of 2002 and Utah saved 365 MW in the winter of 2001. This is one among many instances in which integrated system operations contribute to long-term jurisdictional rate stability.

(c) A larger, diverse system permits more effective planning and provides for better timed and more economic resource selection. For example, merging Utah Power and Pacific Power allowed the integrated company to reduce planning reserve by 240 MW.

(d) The integrated system's access to markets and its multiple delivery points make possible a wider range of financial transactions, including exchanges, which reduce system revenue requirement.

(e) Costs are reduced through consolidation of administrative, management, and corporate functions.

II. Survey of Company Quantitative Studies of the Relative Cost Effects of Load Growth

A. Introduction

The study of the relative cost effects of load growth is an appropriate issue for multi-state process (MSP) examination much like the issue of load loss due to deregulation. When load loss is not significant, the impact can be distributed among all jurisdictions. This approach is typically applied to other costs that vary to some extent by state but not to the extent that it warrants change in cost apportionment.[4]

Concern over load growth occurs when the system is resource short, incremental cost is above average embedded cost and there are differential rates of growth. If the system is surplus, load growth benefits all jurisdictions by shifting existing cost to the growth state. All of the following growth studies begin with the assumption of a resource deficit as faced today looking forward. No systematic examination of study results under alternative assumptions of the key drivers has been undertaken. If a study began in 1990, results would be different.

[4] Examples of state specific costs that have been analyzed in the past include, property taxes, qualifying facilities contracts, and state-specific environmental requirements.

B. Description of Load Growth Studies

In the course of MSP, the Company has responded to nearly 20 data requests to examine the impact of Utah's load growth on other jurisdictions.

The studies share common assumptions, methods, and limitations.

- All studies use the Company's 2003 load forecast, which assumes peak load growth differences among the states that are larger than occurred over the past decade.

- All but one of the studies layer additional load growth and resources on top of underlying load growth assumptions and resource additions. The studies assume resource additions as identified in IRP 2003 (with several adjustments) that minimize total Company revenue requirement.[5] The additions correspond to the 2001 load forecast used in IRP 2003.

[5] Three adjustments are made to Diversified Portfolio I of IRP 2003, two contracts in the western control area are eliminated: a 500 MW off-peak contract from FY 2004-2007 and a flat 200 MW contract in FY 2011; and a 25 MW purchase is added in each control area in 2009. Henceforth, we call this the adjusted IRP 2003.

- All studies assume an underlying system peak resource deficiency in the early years. Resources are then added to meet a 15% reserve margin.

- All studies but one assume that Utah, the largest jurisdiction, is the state that grows. The exception adds to Oregon's projected growth.

- Most of the studies assume the Company's current forward price curves. A high gas and electricity price scenario is also provided for several of the early studies.

- Most of the studies project year-by-year revenue requirement impacts for the 14-year study period 2005-2018 for each jurisdiction. Several of the older studies are limited to results for only 3 of the 14 years.

Detailed results are shown in the appended Tables 1-10 for the following cost allocation approaches: Rolled-in, Modified Accord, Protocol, Modified Protocol, and Hybrid. Study results are not uniformly available for all methods due to the diverse interests of the participants requesting the studies.

Briefly, the following describes the five allocation methods shown in Tables 1-10:

- Rolled-in generally distributes average embedded costs based on relative load.

- Modified Accord is similar to Rolled-in with two modifications: 1) Pre-merger generating plant cost is directly assigned to its respective Division and 2) a fuel-cost adjustment for Company-owned hydro is made in each Division.

- Protocol is similar to Rolled-in with several modifications of importance: 1) Seasonal peaking plant cost is classified 100% demand and its costs and the cost of some seasonal contracts are allocated using output-weighted load-based allocation factors; 2) A coal and hydro adjustment is made whereby some coal and hydro costs are directly assigned to a Division. The hydro endowment is expanded from the Modified Accord method to include the Mid-Columbia contracts.

- Modified Protocol, also known as Decremented Protocol, is an evolving method that here means the following: Rolled-in plus the seasonal treatments proposed in Protocol plus the direct cost assignment of northwest hydro facilities expanded to include the Mid-Columbia contracts to the Division in which they are located and Qualifying Facility (QF) contracts to the State in which they are located; this direct assignment of cost is coupled with changes to cost allocation factors. Jurisdictional loads are decreased (hence, the term “load decrements”) by the amount of northwest hydro and QF output prior to formation of cost allocation factors for remaining production cost. Finally, the cost of Trojan is directly assigned to the former Pacific Division in some of the growth studies.[6]

- Hybrid is a specified direct assignment of the cost of system production facilities to one or the other of PacifiCorp's two control areas; interchange accounting distributes simulated "financial transactions" at market prices between the two control areas; within the control areas, costs are allocated based on Rolled-in.

Briefly, the studies examine: (1) the impact of a one-time increase of 100 average MW of growth, shaped to load; (2) the cumulative impact of Utah continuing to grow faster than the other states over the entire study period; (3) the impact of Utah's peak load growth and (4) the impact of a one-time 1% increase over the current load forecast. The first study approach examines the impact of Utah load growth under various resource addition assumptions. It is also used to examine a case where Oregon rather than Utah grows faster. High gas and electricity price sensitivity cases are conducted for some cases but not others. The cumulative impact study adds only Combined Cycle Combustion Turbine (CCCT) technology.

A detailed description of each study type follows.

[6] Inclusion or exclusion of the Trojan adjustment has no material impact on relative load growth cost results.

Appendix A, Tables 1-4 summarize the results of assuming Utah's load grows in every hour of 2005, with that increment remaining in place through 2014. The load is "shaped" to correspond to Utah's current load shape. It is increased by 100 average MW, which requires a 150 MW resource to meet the peak. A Simple Cycle Combustion Turbine (SCCT), a Combined Cycle Combustion Turbine (CCCT), a coal unit, or a purchase matches the increase in load. Results are provided for five allocation methods. The Net Present Value (NPV)[7] increase in total company cost and its distribution among states is provided for the first five years and the full 14-year period, as well as the percentage of the cost increase that each state absorbs. Percentage changes to each state's revenue requirement are also provided.

In this set of studies, the resource additions closely match the load increase. The advantage of this assumption is that it isolates the resource addition that is "caused" by the actual load increase, filtering out the effects of lumpy resource additions and the underlying load and resource balance. A disadvantage of this study set is that the assumption of a one-time only increase in loads may understate the revenue requirement impact of sustained differential load growth over time.

Table 5 summarizes the results for the study examining cumulative effects that has

[7] Discount rate in all studies is 8.823%.

become known in Utah as DPU 7.3 and in Oregon as OPUC 59 & 60.[8] The purpose of this study is to examine the impact on other states were Utah to grow more rapidly than the average of all jurisdictions less Utah throughout the 14-year study period, as projected by the 2003 load forecast.[9] The study attempts to capture the impact from Utah growing faster than the other states including the effects of lumpy resource additions.

To do this, the study estimates the cost streams of two resource plans, one corresponding to low Utah growth and one to high Utah growth. The study attributes the difference as the cost of Utah growth.

To estimate Utah's load growth in the low case, Utah's growth in energy and peak demand from 2005 to 2018 is set at PacifiCorp's 2003 forecast of average energy growth rate for the other jurisdictions from 2006-2018, or 1.46%. Under this assumption, Utah's peak load increases 795 MW by 2018. In the high case, Utah energy and capacity requirements increase according to the 2003 Company forecast, with post-2005 energy growth of 3.61% and peak growth of 4.68%. In this case, Utah's peak load grows 3,131 MW. Thus, the estimated difference in Utah load growth between the low and high cases is 2,336 MW.

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[8] Oregon and Utah Division of Public Utilities (DPU) staff jointly requested this study which is known in Oregon as OPUC 59 and 60.

[9] Wholesale all-requirements customers make up one jurisdiction.

The low case resource mix uses the adjusted IRP 2003 resource plan with an additional adjustment removing 1,010 MW of resource additions on the east side (510 MW of Gadsby repowering in 2009 and 500 MW of SCCT's in 2013). The high-case resource mix uses the adjusted IRP 2003 resource plan (including the 1,010 MW's that were subtracted in the low case) and adds four 525-MW Greenfield 1 x 1 CCCT's plus $60 million in transmission upgrades in 2007, 2010, 2014 and 2018, for a total of 2,100 MW. Thus, the high case has a total of 3,110 MW more capacity (2,610 MW's of CCCTs and 500 MW's of SCCTs) by 2018 than does the low case.

This study is representative of what could happen should the relative loads of the states remain as forecast in 2003. Large resources are added at points in time, as would occur in reality, so that the resource addition output does not match exactly with load growth at any given point in time. The resources added, however, have not been through the rigors of the IRP process and do not represent a least-cost, least risk portfolio. This and additional factors tend to bias upward the costs of the resource portfolios used in this study (and therefore lessens the amount allocated to the growth state) to meet Utah load growth. For example:

- In the high growth case, only gas-fired CCCT's are added to meet the new load growth from the 2003 load forecast. The CCCT's added are assumed to be 1 x 1 technology which is more expensive than 2 x 1 technology in terms of capital cost, heat rate and non-fuel operating cost. The IRP process would evaluate a mix of resource alternatives including coal and market purchases, and alternative technology configurations - which could be less expensive - to determine the least cost/least risk portfolio. The low case has the advantage of a least cost mix of resources.

- The high case is based on a single forecast of load growth in Utah with large, sustained growth in peak and energy that exceeds historical growth.[10] Impacts from demand side programs, time-of-day rates, and price elasticity are not taken into account and are likely to mitigate sustained Utah load. All else equal, high load growth will tend to amplify any allocational effects.

- Utah peak growth in the low case, 1.46% annually, is actually below the 1.75% average forecasted load growth of the other states. This difference increases the incremental capacity requirement (and hence the cost) of Utah peak load growth by 200 MW (including a 15% reserve margin).

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[10] The assumed 2003 load growth forecast exceeds Utah's historical load growth; for example, over the last eight years, Utah's actual peak hour summer demand growth was 147 MW per year and its summer average energy growth was 69 MW per year. Growth at 147 MW per year would add 2,058 MW of additional supply for summer peak. This study adds 3,110 MW which is the equivalent of 222 MW per year.

- The resource plans for the two cases differ by more megawatts (and hence more dollars) than would be required to meet the incremental Utah load growth. The high case has 2.336 MW higher load by 2018 than the low case, while the high-case resource plan has 3,110 MW more capacity than the low case. Some of this 774 MW of additional resource can be attributed to reserves on the incremental growth. Even with a 15% reserve margin, the incremental need is only 2,686 MW, or 424 MW below the incremental capacity additions.

Thus, Study DPU 7.3 can be viewed as a particularly demanding test of the ability of dynamic cost allocators to properly allocate the cost of load growth to the growing state and therefore represents a high-end estimate of adverse cost effects of load growth.[11] Since it assumes a high load growth and a capacity response that adds an excess amount of high-cost resources, the cost allocated to other states is exaggerated in both percentage and absolute-dollar terms.

[11] The only obvious exceptions to factors causing the modeling results to understate Utah's share of the growth costs is the assumption that system overheads would be unaffected by Utah's growth causing the system to be 7% larger than otherwise. Insofar as the "fixed overheads" in fact grew, the affect of Utah bearing a larger share of such would be diluted. (While the other states' percentage shares would shrink, those percentages would apply to a slightly larger base.) Of course, overheads are allocated to a large degree on distribution plant cost and therefore as a state grows, so to would its distribution plant costs and therefore its allocation of such costs under Rolled-in. This may have an offsetting effect.

Appended Table 6 summarizes the results from initial studies of the effects of Utah's peak load growth, the only studies for which a high gas price sensitivity is available. Results are available for only the Protocol and Modified Accord allocation methods and years 2005, 2009 and 2013. Since the results are similar, only the Protocol results are displayed.

Table 6 summarizes the results of assuming a 100 MW increase in Utah's load in two peak hours, the peak July hour and the peak August hour above the already assumed rate of growth. The load increase is then met by the addition of an SCCT, a CCCT, or a purchase. Because of the extreme assumption of a load increase occurring in only two hours of the entire year, the results are not considered to be robust. However, the information provided by the study set does help inform our conclusions. For example, this study shows that under the Rolled-in allocation method, a state that does not manage its peak growth incurs a hefty penalty. Thus, this method produces appropriate price signals and therefore a proper incentive for load management.

Table 7 summarizes two unrelated studies. The first was an early attempt to understand the cost effect of Utah growing more rapidly than forecast throughout the study period. It assumes that Utah grows 1% faster than projected and adds portions of a CCCT to meet the load growth. The study adds 44 MW in 2007, 10 MW in 2010, and 10 MW in 2015. It is a precursor to the study displayed in Table 5. The other study is a precursor to the studies displayed in Tables 1-4. It assumes 100 average MW of Utah load growth is met by market purchases.

The final studies that will be discussed are shown in Tables 8-10. These studies, known in Utah as CCS 7.2, evaluate the relative cost effects of load growth in Oregon rather than Utah and are akin to the Utah growth studies shown in Tables 1-4. The studies add 100 average MW of shaped load to Oregon, starting in 2005. To meet this load, the studies add either a 150 MW CCCT, a 150 MW SCCT or market purchases to meet the load change.

There is one key difference in the Oregon and Utah studies that explains why the results in the Oregon case show higher growth cost coverage: the CCCT added to meet Oregon growth is lower cost than the CCCT added to meet the Utah growth. The difference in cost assumed is partially based on IRP 2003 information regarding altitude and gas price differences. The remaining cost difference is associated with the choice of CCCT technology. Since the least-cost portfolio in IRP 2003 did not identify technology configuration, the modeling team extrapolated from available IRP 2003 information which resulted in the assumption that a more expensive CCCT is cited in Utah. This assumption is for practical purposes only and does not reflect the cost of a CCCT that would actually be acquired in the Utah area.

Additionally, the assumption that historical load shape in each state will continue in the future may also effect the results. The incremental load in Oregon is assumed to have a higher load factor than the incremental Utah load and therefore lower cost. If a common future load shape was assumed in both studies, the difference in results in the two studies would be smaller.

C. Study Results

Summary results by state for the 100 average MW load growth studies and the DPU 7.3 study that adds 3,110 MW of gas resource are shown below along with key observations for each state. The information summarizes data from Tables 1-5 in Appendix A and provides a state by state review of percentage share of incremental cost.[12] These tables are followed by a table that provides a summary of state revenue requirement impacts for the 3,110 MW of gas resource case. The results for the Oregon growth study are shown following the state by state results of impacts from Utah growth. The tables show percentage share of the net present value increase in total company revenue requirement from adding the indicated resources under five allocation methods over fourteen years.

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[12] Incremental cost means the change in total system cost due to the change in load. Share of incremental cost refers to the amount of revenue requirement increase in a state, due to its receiving a new share of total system incremental cost plus a new share of all existing costs, as a percent of total system incremental cost.

Percent of Utah Incremental Load Growth Cost Borne by Utah

Utah	Rolled-in	Modified	Protocol	Modified	Hybrid
SC/CC 3 110 MW	86.4%	82.8%		87.6%	94.6%
SCCT 150 MW	94.9%	89.2%	88.8%	97.9%	99.9%
CCCT 150 MW	96.4%	90.5%	87.9%	100.8%	97.8%
Coal 150 MW	104.5%	97.8%	95.6%	109.2%	94.6%
Purchase 150 MW	110.6%	103.0%	100.6%	112.7%	98.5%

- Under Rolled-in, Utah picks up between 86% and 111% of the incremental cost of load growth.

- Should conditions modeled remain static for fourteen years, the values greater than100% represents a measure of system integration “risk” of higher cost to Utah and values less than 100% show a system integration “reward” of lower cost to Utah.

- Utah picks up the largest portion of incremental growth costs under Modified Protocol.

- Modified Accord and Protocol allocate less to Utah than Rolled-in because of the direct assignment of Pacific Division resources costs, thereby insulating Utah from an increased share of that Divison’s cost.

Percent of Utah Incremental Load Growth Cost Borne by Oregon

Oregon	Rolled-in	Modified	Protocol	Modified	Hybrid
SC/CC 3,110 MW	6.1%	8.5%		5.3%	-2.1%
SCCT 150 MW	1.7%	5.5%	4.9%	3.6%	-7.4%
CCCT 150 MW	1.0%	4.9%	6.0%	1.7%	-4.4%
Coal 150 MW	-2.6%	1.9%	2.6%	-1.5%	-0.5%
Purchase 150 MW	-6.3%	-1.2%	-0.4%	-3.0%	-4.0%

- Under Rolled-in, Oregon's share of Utah's growth cost ranges from 6% to a negative 6%, again assuming conditions modeled remain static for fourteen years.

- Modified Accord and Protocol allocate more of Utah load growth cost to Oregon than Rolled-in because of the direct assignment of Pacific Division resource costs.

- The Hybrid method does the best job of insulating Oregon from risks associated with Utah load growth.

- Under Modified Protocol, Oregon's share of Utah's growth cost ranges from 5% to a negative 3%, again assuming conditions modeled remain static for fourteen years.

Percent of Utah Incremental Load Growth Cost Borne by Wyoming

Wyoming	Rolled-in	Modified	Protocol	Modified	Hybrid
SC/CC 3,110 MW	3.7%	4.5%		3.4%	5.9%
SCCT 150 MW	2.0%	3.2%	3.2%	-2.8%	7.3%
CCCT 150 MW	1.6%	2.9%	3.6%	-3.4%	5.8%
Coal 150 MW	-0.6%	0.8%	1.4%	-6.3%	4.2%
Purchase 150 MW	-1.3%	0.4%	1.0%	-7.0%	5.0%

- Under Rolled-in, Wyoming's share of Utah's growth cost ranges from 4% to a negative 1%, again assuming conditions modeled remain static for fourteen years.

- Modified Accord and Protocol allocate more of Utah load growth cost to Wyoming than Rolled-in because of the direct assignment of Pacific Division resource costs.

- Under Modified Protocol, Wyoming's cost decreases in all cases but DPU 7.3 where its share of Utah growth cost is 3%.

- Under Hybrid, Wyoming's share of Utah load growth cost ranges from 4% to 7%.

Percent of Utah Incremental Load Growth Cost Borne by Idaho

Idaho	Rolled-in	Modified	Protocol	Modified	Hybrid
SC/CC 3 110 MW	1.6%	1.1%		1.7%	2.4%
SCCT 150 MW	0.8%	0.1%	0.8%	5.7%	3.1%
CCCT 150 MW	0.6%	-0.1%	0.3%	6.2%	2.5%
Coal 150 MW	-0.3%	-1.2%	-0.6%	6.0%	1.9%
Purchase 150 MW	-0.7%	-1.6%	-0.9%	6.1%	2.0%

- Under Rolled-in, Idaho's share of Utah load growth cost ranges from 2% to a negative 1%, again assuming conditions modeled remain static for fourteen years.

- Modified Protocol and Hybrid allocate more of Utah load growth cost to Idaho than Rolled-in.

Percent of Utah Incremental Load Growth Cost Borne by Washington

Washington	Rolled-in	Modified	Protocol	Modified	Hybrid
SC/CC 3 110 MW	2.0%	2.7%		1.8%	-0.6%
SCCT 150 MW	0.5%	1.7%	2.0%	-5.4%	-2.3%
CCCT 150 MW	0.3%	1.5%	1.9%	-6.1%	-1.3%
Coal 150 MW	-0.7%	0.7%	0.9%	-8.0%	-0.1%
Purchase 150 MW	-2.0%	-0.4%	-0.2%	-9.6%	-1.2%

- Under Rolled-in, Washington's share of Utah load growth cost ranges from 2% to a negative 2%, again assuming that the conditions modeled remain static for fourteen years.

- Under the 100 average MW cases, Modified Protocol provides Washington with reduction in costs ranging from 5% to 10%. Results in the DPU 7.3 case show a slight increase in cost that is similar to its effects under Rolled-in.

Percent of Utah Incremental Load Growth Cost Borne by California

California	Rolled-in	Modified	Protocol	Modified	Hybrid
SC/CC 3 110 MW	0.3%	0.5%		0.3%	-0.2%
SCCT 150 MW	0.1%	0.3%	0.3%	0.9%	-0.5%
CCCT 150 MW	0.0%	0.3%	0.3%	0.8%	-0.3%
Coal 150 MW	-0.3%	0.0%	0.0%	0.7%	-0.1%
Purchase 150 MW		-0.1%	-0.1%	0.8%	-0.3%

- California results are close to zero regardless of method or study assumptions.

Revenue Requirement Effects of 3,110 MW of Gas Resources added for Utah Load Growth

(NPV from 2005-2018)

	Rolled-In	Modified Accord	Modified Protocol	Hybrid
	Increment as % Share of Rev. Req.	Increment as % Share of Rev. Req.	Increment as % Share of Rev. Req.	Increment as % Share of Rev. Req.
Utah	14.3%	13.6%	14.3%	15.6%
Oregon	1.5%	2.1%	1.3%	-0.5%
Wyoming	2.1%	2.6%	2.0%	3.4%
Washington	1.6%	2.2%	1.5%	-0.5%
Idaho	2.0%	1.4%	2.1%	3.1%
California	0.9%	1.4%	0.8%	-0.6%
System	7.1%	7.1%	7.1%	7.1%

- Impacts shown are very modest and in most cases immaterial.

- For example, the 14% increase in Utah's 14-year NPV revenue requirement translates into a two percent average annual change in revenue requirement, an amount that can be swamped by other factors of cost change like cost of capital.

- The 1.5% increase in Oregon's 14-year NPV revenue requirement is equivalent to an average annual increase in its revenue requirement of a quarter of one percent. Again, this is an amount that would be easily swamped by other cost changes and unlikely to be the driving cause of a rate change proceeding.

Percent of Oregon Incremental Load Growth Cost Borne by each State

	Add (150 MW) CCCT Resource		Add (150 MW) SCCT Resource		Add (150 MW) Purchases	
	Rolled-In	Modified Protocol	Rolled-In	Modified Protocol	Rolled-In	Modified Protocol
Utah	-4.0%	63.2%	-0.9%	63.1%	-18.1%	65.0%
Oregon	104.7%	40.5%	99.8%	38.1%	126.6%	46.5%
Wyoming	0.1%	-3.9%	1.0%	-2.5%	-3.2%	-7.8%
Washington	-0.4%	-6.8%	0.1%	-5.5%	-2.8%	-10.6%
Idaho	-0.3%	6.0%	0.1%	5.8%	-1.9%	6.0%
California	-0.1%	1.0%	0.0%	1.1%	-0.6%	1.0%

- Under the Rolled-in method, the fastest growing jurisdiction (Oregon in this instance), again bears the bulk of the costs of its growth.

- Under Modified Protocol, Oregon is protected from some of the costs of its own growth, an unintended consequence of the decrement approach to hydro and QF cost allocation.

- Under Modified Protocol, Utah bears the largest percentage of Oregon's growth cost.

- The reason that the Oregon cost burden of 105% is similar to Utah's coal cost burden of 105% in the previous studies is that the Oregon CCCT cost is assumed to be closer to a coal cost than a Utah CCCT cost.

D. Discussion

The fraction of growth-related costs that are absorbed by the growth state depends on several factors. If one state grows and the others do not, the growth state picks up a large percentage of the generation costs caused by that growth, under the Rolled-in method and (to a lesser extent) the Modified Accord, Protocol, and Modified Protocol approaches as well as the Hybrid within each control area. The growth state picks up more of the fixed costs of transmission and overheads, more of the existing generation system costs, and its increased share of the resources added to meet growth.

Non-growing states benefit from the growth by spreading the costs of transmission and overheads, and the existing generation, over a larger total load, but pay a share of the costs of the growth-related resources. Since these components work in opposite directions, a non-growing state may have higher or lower costs as a result of growth elsewhere.

The balance of those components depend on a number of factors. Some of these are stable, such as the level of overheads and transmission, but others are subject to change and uncertainty. The following summarizes what we have learned from the studies as well as underscoring their strengths and limitations.

Load and Resource Balance

Concern over the cost of load growth occurs when the system is resource short, incremental cost is above average embedded cost and there are differential rates of growth. If the system is surplus, load growth benefits all jurisdictions by shifting existing cost to the growth state. All of the above growth studies begin with the assumption of a resource deficit as faced today looking forward. If a study began in 1990, results would be different.

Lumpy Resource Additions

Resource additions can be sized to correspond to load growth, as is the case with market purchases, or may be added in large lumps, as is the case with a CCCT or a Coal unit. Such lumpy additions reduce the size of a resource deficit or create excess capacity. Whether this is helpful or harmful depends on the assumed relationship between the cost of physical capacity and market prices. If market prices are forecast to be high, then the reduction in expensive purchases or the sale of the surplus power is a benefit. If the new units are forecast to be more expensive than market, then the opposite is true.

Under the base studies, the use of average hydro and a single forecast of electric and gas prices understates the volatility of the wholesale markets. All but the high gas studies assume that excess capacity is harmful. This information can be gleaned by examining the table below in the following section or the appended Tables 1-4. In the set of studies summarized, the 100 average MW increase in Utah's load is assumed to be exactly matched by one of four resources thereby removing any affect of lumpiness.

Resource Costs

If the costs of the added resources are low, the benefits to the non-growing states of spreading the fixed costs over a larger load base can exceed the costs of their share of the new resources. If the costs of the added resources are high, the opposite is true, and the allocation to the non-growth states rise.

This pattern can be seen in the chart below. All five cases assume additional load of 100 average MWs shaped like existing load; they differ by state incurring the load increase and by the cost and type of resources added to respond to the growth. The share of the incremental cost that is borne by the faster growing state rises as the costs of the incremental resources fall. The following table is for 2005-2018 under Rolled-in, but the pattern is similar for other methods and periods:

	Resource Type	Load Growth State	Cost Increase: 14-YR NPV ($ millions)	Percent borne by Faster Growing State
Table 10	Purchases	Oregon	$249	127%
Table 4	Purchases	Utah	$282	111%
Table 3	Coal	Utah	$318	105%
Table 8	CCCT	Oregon	$319	105%
Table 9	SCCT	Oregon	$341	100%
Table 2	CCCT	Utah	$365	96%
Table 1	SCCT	Utah	$375	95%

The share of growth cost allocated to the faster growing state varies inversely (and almost linearly) with the incremental net cost of growth. When the CCCT is added to meet Oregon growth, the net system cost is $319 million; when Utah is the faster growing state, the cost of adding a CCCT is much higher, $365 million. When a coal plant is added to meet Utah's load growth, both the cost to the system ($318 million) *and* Utah's share of the cost (105%) are almost identical to the system cost and Oregon's share with a CCCT added.

This comparison of the 100 average MW load growth studies under Rolled-in allocation indicates: (1) There is a consistent inverse relationship between the net cost of the resource addition and the percent allocation to the faster growing state; (2) that relationship is very close to linear, and (3) the relationship seems to hold for any type of resource addition and no matter which state is the growth state.

A similar effect occurs for the cases shown in Table 6 with 100 MW Utah summer peak growth met by various resources and with two levels of gas prices (and hence electric market prices). In that set of cases, the incremental costs are highest with the addition of the SCCT, lower with the CCCT addition, and negligible with market purchases. As the cost of load growth falls, the share of load growth costs assumed by the growth state (Utah) rises, from 70% to 72% to more than 75 *times* the incremental system cost (in years 2005 and 2009, assuming PacifiCorp base natural gas and electricity prices).

In the high gas cases, total system costs rise less than half as much as they do with PacifiCorp's base gas prices in response to the increased load. This makes sense, since the additional energy from adding a CCCT displaces expensive purchases and allows sales into a high-priced market. (The extra load growth only affects the peak hours, so most of the CCCT's energy is available to meet existing load.) As a result, Utah picks up a higher percentage of the incremental costs in the high gas-price case.

These observations lead to a broader conclusion: a least-cost expansion plan minimizes the effect of one state's load growth on the other states and may result in growth in one state reducing costs to the other states. In the two-hour peak-growth cases, adding a CCCT or SCCT is a relatively expensive response to needle-peak growth. A more appropriate, less expensive response to load growth also leads to more of the cost being borne by the growing state.

Embedded Costs

The same considerations that drive the sensitivity to new resource costs also apply to embedded costs for overheads, transmission and generation. If the embedded costs rise, due to hydro relicensing requirements or pollution controls, for example, a faster-growing state will tend bear a higher percentage of the incremental costs of growth, and less of the net costs of growth will be borne by the slow-growing states.

E. General Conclusions from Quantitative Studies

Studies performed by the Company indicate that the portion of load growth cost borne by the faster growing state varies depending on assumptions about the future and upon allocation method. Study results based on a qualified range of assumptions show that the portion of load growth cost borne by the faster growing state varies but is generally a large portion. Most studies show that significant growth costs are borne by the growing jurisdiction and that the possible risk to slower growing states may be small enough to absorb as other costs associated with system integration are absorbed.

Of the allocation methods examined in the studies, it appears that the Rolled-in allocation method performs well in producing results that not only direct load growth cost to the growing state but that also provides reasonable and stable distribution of growth cost among slower growing states. One reason is because Rolled-in more broadly distributes the effects of growth across jurisdictions than the other methods examined. When another allocation method, like Modified Accord or Modified Protocol, directly assigns a portion of generation cost to some jurisdictions but not others, distortions in the allocation of growth costs may occur for some states.

Sensitivity analysis also shows that distribution of load growth cost among states is more stable under Rolled-in allocation than under Modified Protocol because it does not contain the attenuating effects of hydro and QF load decrements which are included in the Modified Protocol method. Further, when Oregon is assumed to grow rather than Utah, the Modified Protocol allocates over 60% of the incremental cost of Oregon's growth to Utah. In order to ensure proper cost accountability and price signals and for durability, it is important to identify an allocation method that is robust under a variety of future conditions.

The potential cost of the risk to slow growing states from this study must be taken in context because sensitivity studies indicate that the type, timing and cost of resource additions drives the extent of load growth cost allocated to the fastest growing state. The better the match of load to resource and the lower the cost of the resource, the greater the cost allocation share to the growing state. When load growth and resource additions match, the growing state bears near 100% of its growth costs.

The study results showing less than 100% growth cost recovery by the growing state appear to be caused in part by lumpy resource additions and, consequently, periods of excess capacity as plants are brought on-line to meet expected load growth. This occurs whether or not there is differential state load growth. Indeed, the Company recently adopted a higher planning reserve target that is part of the resource addition criteria. It is not reasonable to expect the more rapidly growing jurisdiction to bear 100% of the cost of Company planning reserve decisions. All jurisdictions benefit from some excess capacity as it provides greater reliability, reduced market exposure and additional opportunity sales that are shared uniformly among states.

An implicit assumption of this analysis is that 100% recovery of the incremental costs of growth is a reasonable target. Why not 120%? One answer is that a method that targets greater than 100% for the faster growing jurisdiction implies a target of reduced cost in a slower growing jurisdiction which may lead to perverse incentives. Taken to the extreme, this means that under all cases, a slower growing jurisdiction would always benefit from economic growth in another state; one envisions the crafting of state policies designed to advance economic development in another state or to discourage energy conservation efforts in a faster growing state.

Putting the issue in historical perspective underscores that all of the studies performed to date analyze a high-end cost of potential adverse effects of the relative cost of load growth. The conditions that prevail today or that are projected in these studies are unlikely to remain constant for fourteen straight years. Recall that during periods of excess capacity and incremental cost less than average cost, the growth in one state can reduce system costs as it did in the 90's. Making changes to an allocation method specifically to address what is perceived today as a load growth problem may not be warranted, given that there are unknown and uncertain events that will occur in the future.

Finally, analysis to date indicates that least-cost planning is key to mitigating load growth cost impacts.

III. Placing the Issue in Historical and System Integration Context

A. Historical

History shows us that the future unfolds in expected and unexpected ways. The current conditions and projections that are the basis for the assumptions used in the studies examined in this paper are, in many important aspects, the opposite of conditions over the last ten years. The key drivers of the study results, i.e., load forecasts, system load and resource balance, market prices, incremental and average cost, and wholesale sales activity, have changed significantly over the past decade. The following examples illustrate such changes.

Substantial changes have occurred over the past 14 years. The 1989 merger of PacifiCorp Maine with Utah Power and Light (UPL) formed an integrated company that had surplus supply and peaked in the winter. System revenue requirement in 1989 was reported to be $1.8 billion with a rate base of $4.9 billion. The integrated company now peaks in summer and has a resource deficit. System revenue requirement is now $2.6 billion with a rate base of $7.3 billion.[13]

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[13] Source of revenue rquirement data: 1989 data is from the semi-annual report for year-end December 1989 and current data is from the semi-annual report for the 12-month period ending September 2003.

Load Forecasts

From 1993 until 2001, load forecasts used in supply planning projected relative growth rates among states that ranged from 2% to 3% except for western Wyoming which was forecast to grow 1%.[14] Actual growth rates among states during this period was much different, with Utah growing faster than the 3% and Oregon growing more slowly than 2%. Until 2001, the total system load was forecast to remain a winter peaking system but with summer peaks beginning to approach or match winter peaks. The recently acknowledged IRP 2003 forecasts reflect a summer peaking system and the relative growth rates of the past ten years.

Load and Resource Balance

The current load and resource balance is the result of historical expectations and related decisions. In the late 1990's, planning decisions were made under the threat of loss of load from retail access and the expectation of robust wholesale markets. With the slowing of retail access initiatives and fundamental changes in wholesale markets, the load

[14] RAMPP-3, Load Forecasting Technical Appendix, April 1994, pages 57-61. Subsequent IRP's refer back to this forecast or don't reveal changes in relative growth rates until IRP 2003, completed May 2003.

and resource balance that was once expected has not materialized.[15]

Market Price and the Relationship of Incremental and Average Cost

[15] For example, these assumptions moved system summer deficit from 2002 as expected in 1995 out to 2012 in 1997.

A key assumption in the 1990's and through to 2001 was the expectation that prevailing low natural gas and wholesale electricity prices would remain low throughout the planning period. This expectation implied that new resources would be lower than or very close to the average cost of existing resources. Under this assumption, load growth above forecast would have the effect of lowering system cost. In IRP's from 1994 to 1997, the Company studied the cost effects of additional load growth and concluded that "All three planning cycles showed the same pattern of lower customer prices with higher levels of load growth, and higher customer prices with lower levels of load growth."[16]

Wholesale Sales

Another example of a major industry change to unfold differently than planned is the level of wholesale activity influencing retail rates. PacifiCorp pursued a strategy of active wholesale participation in the 1990's. Wholesale sales revenues grew from $219.5 million and 10 percent of total electricity sales in the year following the UPL/PPL merger to $2.1 billion and 47 percent of total electricity sales by March of 2001. Wholesale sales revenues grew steadily from 1989 through 1997, then declined somewhat in 1998 and 1999. They rebounded, reaching their peak in 2001. They have fallen by almost half over the last two years to 31 percent ($1.5 billion) of total electricity sales. This data

[16] RAMPP-5, page 88.

shows the volatility of a significant component of revenue requirement that can move from year to year in unknown magnitude.

Other Changes

Other characteristics of the integrated system and market conditions changed in over the past 14 years. PacifiCorp sold its Montana and Northern Idaho distribution systems, it planned to but did not sell its California holdings, and the northwest economy slowed. Throughout most of the period, Utah experienced robust growth while Oregon's growth rate was relatively flat. Additionally, beginning in 2000, PacifiCorp included as firm loads, large customers in Utah and Idaho that had formally been characterized as non-firm loads and were therefore excluded from formation of the System Capacity (SC) and therefore System Generation (SG) cost allocation factors. As a result, the UPL division, even with Wyoming load losses, is today as big as the PPL division.

The change in the size of the two divisions and the difference in relative growth rates are demonstrated by a review of the allocation factors. Although a one-to-one correspondence between jurisdictional load growth and changes in allocation factors does not occur due to weather normalization and the varying treatment of both special contracts and interruptible loads, relative changes can be seen.[17]

[17] For example, from 1994 to 2002, Utah jurisdictional sum of monthly peak demand (its absolute load

growth) grew by 3.7% but its sum of monthly peak demand coincident with the system, its growth relative to other states and the basis for the system capacity allocation factor, grew by 5%. This difference is primarily due to changed treatment of interruptible loads. Also, aside from the load-growth effect, a review of allocation factor changes over time does not provide a basis for understanding other influential sources of cost change.

- As shown by the rolled-in SG allocation factor, the Pacific Division in 1989 was 62.2% of the total system and the Utah Division 37.8%. By September 2003, the Pacific division had declined to 52.0% while the Utah division had grown to 48.0%. Measured by the rolled-in SE allocation factor, the Pacific division in 1989 was 61.1% of the system and the Utah division 38.9%. By September 2003, Pacific was 51.2% and Utah 48.8%.

- The rolled-in SG allocation factor reveals Utah as having grown from 28% of the system in 1989 to 39.8% by September 2003. Oregon, which began the period at 33.8% of the system, remained at about that level through March 2001, but has since declined to 28.9% as of September 2003. The rolled-in allocation SE factor indicates Utah was 28% of the system in 1989 but 39.6% of it by September 2003. Oregon began at 31.8% in 1989, grew to 32.2% by March 2001, but has since declined to 27.1% by September 2003.

This brief review of history holds several lessons.

First, the world is dynamic and changes in both anticipated and unanticipated ways.

Second, as conditions change, the perception of risk changes. The current focus on the risk of higher cost due to Utah load growth is the result of current conditions.

Today, the system is resource short and the market is known to be volatile. However, should market conditions again change, so would the perception of system integration risk.

Third, concern of higher cost from a growth state under current circumstances must be put in the context that growth can also lower cost under different circumstances. History shows that excess capacity can either lower or raise average system cost depending on the relationship between incremental and average cost which varies through time. Recall that only five years ago the deregulation issue of the day was “stranded cost,” implying that for the next twenty years incremental cost and/or market prices would be less than average.

Fourth, the role played by wholesale sales revenues, treated as credits against cost of service, is significant. Wholesales sales revenues are not stable, as they are related to the regional bulk power market which can be quite volatile. For consistency and equity, any interjurisdictional allocation of wholesale sales revenues should follow the “matching principle” in which the sharing of these revenue credits among retail jurisdictions should closely reflect the manner in which the costs of serving wholesale customers is shared among the retail jurisdictions. The choice of interjurisdictional allocation method with respect to the treatment of wholesale sales revenues can have significant risk implications on retail ratemaking.

Finally, what may initially appear to be the result of Utah growth becomes on closer inspection the result of a complex mixture of state and federal policy, economic conditions and PacifiCorp's management decisions as well as Utah load growth. PacifiCorp's current and expected summer deficit and need for additional resource is the result of past decisions based on expectations about the future as well as projected Utah load growth.

B. Integrated System Implications

1. Seasonal and Diurnal Load Diversity Benefits

Comparison of both absolute and relative state loads shows that each state benefits from lower costs due to lower capacity cost associated with the fact that each state's contribution to coincident peak is lower than its non-coincident peak demand. The Company projects that in 2005, peak load for the integrated system will be more than 600 MW less than the sum of the divisional peaks, avoiding over 600 MW of capacity cost.

Similar analysis of actual data reveals state-level load diversity benefit. From 1994 to 2002 [18] each state's seasonal peak coincident with the system was below the state's actual peak in most years and substantially below in at least one year. This is true in both

[18] The period of analysis is due to data availability.

summer, when state loads peak in different times of the year, and winter, when state loads peak at different times of the year and day. For example:

- Utah's actual winter peak in 2001 was 365 MW higher than its contribution to winter coincident peak
- Oregon's actual winter peak in 2002 was 432 MW higher than its contribution to winter coincident peak.
- In summer 2002, Utah saved 52 MW and Oregon 163 MW.

This integration cost advantage appears to be persistent. For every state from 1994 to 2002, the sum of each state's monthly contribution to system peak is less than the sum of its monthly actual, non-coincident, peaks.

2. Long-Run Planning and Resource Acquisitions

Load diversity also provides a system cost advantage for planning and resource acquisitions. It provides a hedge against higher costs when local loads change unexpectedly. An economic downturn in a local economy or the loss of a large industrial customer can surprise planners and result in higher rates for local ratepayers when fixed costs are recovered over fewer sales. Economic growth is also difficult to forecast with accuracy. When loads materialize unexpectedly, or fail to appear as expected, unplanned for surplus or deficit capacity will result. The total load across six states is almost certain to be less volatile than the load of any one state, especially given the differences in the economies and climates of PacifiCorp's states. For example, a load downturn that would be devastating to a separate company serving PacifiCorp's Wyoming or Idaho territory is a minor blip in PacifiCorp's total load. Since load changes in one jurisdiction can offset adverse load changes in another jurisdiction, the adverse effects of an unexpected change in demand can be minimized and distributed across all sales.

A combined load is more stable than a single load and can lead to better planning of resources, more efficient use of the existing system and therefore lower prices and greater rate stability for customers. For example, although PacifiCorp did not forecast the lower loads that materialized in Oregon or the higher loads that materialized in Utah, its forecast of system demand growth is remarkably close to actual. This more stable load allows the Company to mitigate, to some extent, adverse consequences of unexpected state by state load changes.

In addition to the effects of load diversity, merging Utah Power with Pacific Power allowed the combined company to use hydro resources more efficiently, reducing planning reserves by 240 MW. This allowed the Company to avoid resource additions and reduce revenue requirements compared to separate operation of the two divisions.

3. Operational Efficiencies, Financial Transactions

The integrated system's access to markets and its multiple delivery points make feasible a wide range of financial and physical transactions, including exchanges, which reduce the system revenue requirement. Integrated system efficiency depends upon full use of the transmission system, both today, and, in the face of market structure and other institutional uncertainties, tomorrow. The method of cost recovery must not be an impediment to the Company's ability to exploit these opportunities for the benefit of all ratepayers.

Since the inception of the Utah/Pacific merger, we can identify some but not all of the transactions and evidence that show how PacifiCorp captures such integration efficiencies. For example, PacifiCorp's steam plant average capacity factor increased from 48% in 1988 to 77% in 2002 (reaching a high of 85% in1994) which reduce net power costs.[19] The Cholla/APS transaction provided additional winter resource and firm transmission access to desert southwest market hubs, adding operational flexibility and opportunities for more economy purchases and sales. We note that following significant

[19] Source: POWERdat 4.0.

wholesale power and wheeling price increases in 2000 and 2001, PacifiCorp essentially doubled the quantity of electricity characterized as exchange transactions. Exchanges can allow both buyer and seller to hedge wholesale power and wheeling prices.[20]

Additionally, two forward-looking studies indicate positive merged system benefits from a subset of operational efficiencies. Studies 50.4 and 50.5 compare future operation of the merged system with that of two separately-optimized systems. In both cases, the integrated system is lower cost. Study 50.4 indicates that the NPV of company revenue requirement would be almost $300 million higher over a 15-year period for two stand-alone systems compared to the integrated system. Study 50.5 indicates that the NPV of company revenue requirement would be about $200 million higher over a 14-year period for two stand-alone systems compared to the integrated system. The studies are based on an illustrative split of generation and transmission resources and responsibility for wholesale sale transactions and under different assumptions regarding future resources added, different fuel and wholesale power market prices. Implications for the distributional effects of the subset of operational efficiencies in these two studies have been raised and a discussion of this is in Appendix B.

4. Organization Efficiencies and Overheads

[20] Source: POWERdat 4.0.

The integrated system benefits from consolidation of administrative, management, and corporate functions. It permits flexible and more effective access to capital markets. Indeed, such efficiencies were noted as part of the basis for merger approval in both Utah and Oregon.

Overheads are a substantial portion of the cost structure. These costs, which are unlikely to grow as rapidly as the generation costs incurred to serve load growth, are allocated using load-based allocation factors. An increasing share of these costs will be allocated to the more rapidly growing jurisdiction, providing a benefit to slower growing jurisdictions.

5. Risk and Uncertainty

As a general statement of the utility's economic optimization problem, a larger number of feasible options, such as is made possible by the integrated system, is more likely to result in lower costs to the benefit of all ratepayers. The risks posed by any sort of change on the system, of which the following are illustrations, are lessened for a particular jurisdiction as a result of being broadly diffused across all jurisdictions. The merged system provides rate stability not only through diffusion of impacts but through more efficient resource choice and use. A further consequence of sharing risk across the integrated system is that shareholders are less exposed to the events and policy decisions in single jurisdictions, with favorable cost-of-capital implications. In addition, it is a desirable aspect of decisionmaking in the context of uncertainty to retain rather than to prematurely foreclose options. The integrated system provides greater flexibility to deal with uncertain future events than would any smaller configuration of the utility.

a. Jurisdictional Growth Rates

The relative rates of growth among jurisdictions may increase or decrease in the normal course of affairs. Whether or not jurisdictional load growth variations are detrimental or beneficial depends on the relation between incremental and embedded costs. If incremental cost is less than or equal to embedded cost, one jurisdiction's growth can reduce the costs allocated to other jurisdictions. In addition, service territory may expand or shrink according to decisions that may not have been anticipated or as opportunities arise. When a state loses load, the other states absorb the fixed costs associated with the lost load. This occurred in Oregon with the loss of the Hermiston and the James River Halsey loads, and in Wyoming with the loss of the Trona industrial loads and the recent sale of the Cody area.

b. Cost and Reliability Impacts of Thermal Outages, Availability, and Maintenance; Varying Conditions of Hydro, Streamflow, Rainfall/Snowpack; and Unexpected Changes in

Fuel

Prices and Wholesale Market Prices:

In all cases, the integrated system offers the ability to defray risks over a broader set of loads and resources. The integrated system's portfolio of diverse resources sources not only lessens any jurisdiction's dependence on a single resource but offers a wider array of replacement resource opportunities in, for example, the case of expiring long-term wholesale contracts in the northwest.

The risk of thermal outages is spread across the system. The integrated system gives greater flexibility for timing maintenance to economic and operational advantage plus the ability to rely on the generation and transmission resources and opportunities afforded by a larger, more diverse system in the event of unplanned outages.

The integrated system's broader reach, encompassing more diverse loads and a vast transmission system, makes possible in general the more effective use of existing resources, whether to serve retail loads and to participate in wholesale markets. The risk of unexpected, sudden and dramatic changes in fuel and wholesale electricity prices, which may bring unplanned, adverse cost-incurrence and operational consequences, is lessened for a single jurisdiction as a result of being broadly distributed across all jurisdictions in the integrated system. Again, the exposure of any one jurisdiction is diminished by being part of a larger system. This allows more opportunities and flexibility for optimizing the system and lowering overall costs.

c. National and Regional Policies: Hydro Relicensing, Carbon Tax; Market Structure, Federal and State Restructuring Initiatives:

To the extent these matters of public policy may result in increased costs, the consequences are lessened for each jurisdiction by being spread across all jurisdictions in the integrated system. The integrated system can more readily adapt to such changes than could any single jurisdiction standing alone because of its greater opportunities, flexibility and resources diversity.