BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

In the Matter of PACIFICORP, dba PACIFIC POWER, Petition for Approval of the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol.	)))))	UM 1050 CROSS EXAMINATION EXHIBITS OF NOBLE AMERICAS ENERGY SOLUTIONS LLC

Noble Americas Energy Solutions LLC ("Noble Solutions") hereby submits its Cross Examination Exhibits in this proceeding before the Public Utility Commission of Oregon ("OPUC" or "Commission"). Based on the record and discovery provided at this time, Noble Solutions intends to admit the following exhibit at the hearing:

Exhibit: Noble Solutions/200

Description: Reply Testimony of PacifiCorp Witness Gregory Duvall in Docket UE 267

DATED this 12th day of May, 2016.

RICHARDSON ADAMS, PLLC

/s/ *Gregory M. Adams*

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Docket No. UE 267
Exhibit PAC/400
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Gregory N. Duvall

March 2014

Q. Are you the same Gregory N. Duvall who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony addresses the Consumer Opt-Out Charge and the calculation of the transition adjustment in the Company's Five-Year Cost of Service Opt-Out program (Five-Year Program). Specifically, my testimony responds to the joint testimony supporting the partial stipulation filed by Staff of the Public Utility Commission of Oregon (Staff), Noble Americas Energy Solutions LLC (Noble Solutions), Industrial Customers of Northwest Utilities (ICNU), Wal-Mart Stores, Inc. (Wal-Mart), Constellation NewEnergy, Inc. (Constellation), Shell Energy North America (US) L.P. (Shell), Safeway, Inc., The Kroger Co., Vitesse LLC, and the Northwest and Intermountain Power Producers Coalition (collectively, Stipulating Parties). I also respond to the individual testimony filed by Staff, ICNU, Wal-Mart, and Constellation, Shell, and Noble Solutions.

Q. Please summarize your testimony.

A. I address two major issues related to the Five-Year Program. First, I explain the Company's modifications to the Consumer Opt-Out Charge, demonstrate the need for the charge, and respond to the Stipulating Parties' criticism of the charge. Second, I outline three changes to the transition adjustment calculation in the Five-Year Program: (1) valuing freed-up energy using the same methodology employed in the annual Transition Adjustment Mechanism (TAM) under Schedule 294; (2) removing the split between heavy load hours (HLH) and light load hours (LLH); and (3) forecasting only 50 average megawatts (aMW) of incremental departing load to calculate the transition adjustment, instead of the maximum 175 aMW. I also explain why the Company rejected some of the other changes to the calculation of the transition adjustment proposed in the partial stipulation.

Q. What is the overall impact of these changes?

A. These changes substantially reduce the Consumer Opt-Out Charge. For example, the Schedule 47/48 charge goes from $17.30/MWh to $6.18/MWh. A chart comparing the charges using a 20-year forecast and a 10-year forecast including the Company's modifications to the transition adjustment calculation is attached as Exhibit PAC/401.

MODIFICATIONS TO THE CONSUMER OPT-OUT CHARGE

Q. Please describe the changes the Company is proposing to the Consumer Opt-Out Charge in its Five-Year Program.

A. The Company proposes to retain but modify its Consumer Opt-Out Charge. As originally proposed, the Consumer Opt-Out Charge values the fixed generation costs incurred by the Company to serve customers, offset by the value of the freed-up power made available by the departing customers, for years six through 20. The Company now proposes that the Consumer Opt-Out Charge account for only years six through 10, rather than six through 20.

Q. Why did the Company make this change to the Consumer Opt-Out Charge?

A. The Company made this change in response to the Stipulating Parties' concern that the Consumer Opt-Out Charge would discourage participation in the Five-Year

Program. While the Company is concerned about cost-shifting resulting from the Five-Year Program, it also wants the Five-Year Program to be a viable option for customers. For this reason, the Company modified the Customer Opt-Out Charge to cover transition costs over a shorter time horizon, balancing the competing interests of competitive market development and protection against cost-shifting more in favor of direct access customers.

Q. Why didn't the Company just agree to eliminate the Consumer Opt-Out Charge in its Five-Year Program?

A. Under PacifiCorp's particular circumstances, elimination of the Consumer Opt-Out Charge is contrary to Oregon direct access laws and regulations. ORS 757.601(1) provides that direct access may not cause the unwarranted shifting of costs to other customers. OAR 860-038-0160(1) expressly provides that direct access customers must pay or receive 100 percent of transition costs or benefits. PacifiCorp cannot contravene Oregon's direct access laws and regulations by agreeing that customers may permanently leave cost-based supply service without meeting their transition cost obligations.

Q. Has any party provided financial analysis challenging the accuracy of the Company's calculation of the Consumer Opt-Out Charge?

A. No. The Stipulating Parties have not provided any evidence challenging the key factual issue in this case: whether PacifiCorp has significant transition costs beyond those covered by the payment of annual Schedule 200 charges in the initial five-year period. PacifiCorp's calculation of the Consumer Opt-Out Charge uses the "ongoing valuation" approach for calculating transition costs. Under this approach, the

Commission determines the "transition costs or benefits for a generation asset by comparing the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period."[1]

The Stipulating Parties claim that PacifiCorp's projected market prices are "speculative." The Company does not agree with this claim, and such projections are a required part of the Commission's transition adjustment calculation. In addition, PacifiCorp developed its market price forecast for the Consumer Opt-Out charge using the same forward price curves it uses for the one- and three-year transition adjustments. Notably, the Stipulating Parties have not supplied any alternative financial or market analysis demonstrating that departing direct access load will be neutral or positive in terms of impacts on other Oregon customers.

On this record, it is fundamentally undisputed that direct access customers could shift cost responsibility for up to $38 million (measured over a 10-year period) in transition costs to other customers unless direct access customers are required to pay PacifiCorp's modified Consumer Opt-Out Charge. See Exhibit PAC/402.

RESPONSES TO OBJECTIONS TO CONSUMER OPT-OUT CHARGE

Q. What are the Stipulating Parties' primary objections to the Consumer Opt-Out Charge?

A. The Stipulating Parties' primary challenges to the Consumer Opt-Out Charge are that: (1) load growth fully absorbs the transition costs covered by the charge; (2) while cost-shifting will occur under Section X of the 2010 Protocol, the Commission should assume that Section X will be modified to eliminate this impact; and (3) Portland

[1] OAR 860-038-0005(42).

General Electric Company's (PGE's) five-year opt-out does not include a Consumer Opt-Out charge. I respond to each of these arguments below.

LOAD GROWTH DOES NOT NEGATE TRANSITION COSTS

Q. What is the Stipulating Parties' theory around load growth and transition costs?

A. The Stipulating Parties assert that load growth will replace the departing loads from the Five-Year Program and negate any transition costs.

Q. Please respond to the Stipulating Parties' load growth argument.

A. This argument is flawed for at least three reasons. First, the requirement of OAR 860-038-0160(1) for 100 percent payment of transition costs does not contain a load growth exception. Second, load growth does not negate the existence of transition costs; rather, it shifts these costs from direct access customers to remaining cost of service customers including new customers. Third, it is undisputed that PacifiCorp is not experiencing load growth in Oregon and does not expect to add 175 aMW of Oregon load in a forecasted 20-year horizon.[2] While the Stipulating Parties point to load growth on a total-company basis, Section X of the 2010 Protocol (discussed below) effectively precludes consideration of load growth outside of Oregon. Thus, even if the Stipulating Parties' load growth argument was theoretically sound (which it is not), the factual predicate for the argument is absent in this case.

Q. Staff also argues that the Company will be able to scale back extensive front-office transactions in response to the departing direct access load and thereby mitigate any transition costs beyond five years.[3] Do you agree?

A. No. Consistent with the Stipulating Parties' argument on load growth, the

[2] See PacifiCorp Response to OPUC 2, at Staff/103, Compton/2.
[3] Staff/100, Compton/2-3, 10.

requirement of OAR 860-038-0160(1) for 100 percent payment of transition costs does not contain a front-office transaction exception. Moreover, this argument ignores the fact that the Consumer Opt-Out Charge already accounts for changes in front-office transactions. The Company calculates the Consumer Opt-Out Charge using two GRID runs, one with the direct access load and one without. The GRID run that does not include the direct access load necessarily takes into account how the Company's system will respond to the reduced load—including how front-office transactions will be affected. If the departing load resulted in less front-office transactions, this effect is already captured in the calculation of the Consumer Opt-Out Charge. The fact that the savings that result from a reduction in front-office transactions do not fully offset the revenues lost from the customers choosing direct access is the very reason there are transition costs.

Q. Has the Commission ever addressed the impact of departing direct access load on PacifiCorp's front-office transactions?

A. Yes. In docket UM 1081, the Commission specifically rejected ICNU's so-called "market plus" approach to calculating the transition adjustment. This "market plus" approach assumed that the loss of direct access load will cause PacifiCorp to avoid power purchases, rather than cause PacifiCorp to avoid power sales.[4] The Commission specifically rejected this "market plus" approach because it was not convinced that the Company's actual operational response to departing direct access load would be limited to reductions in front-office transactions.[5] Rather, the

[4] Order No. 04-516 at 10.
[5] Order No. 04-516 at 11-12.

Commission required the Company to use GRID to more accurately capture the full effect of departing load on PacifiCorp's system.

Q. Noble Solutions, Constellation, and Shell claim that five years is sufficient time for the Company to adjust its procurement strategy to account for departing load.[6] Please respond.

A. In the near term, the most likely impact of direct access on the Company's procurement strategy will involve changes in the front-office transactions. As described above, these changes are already captured in the GRID runs used to calculate the Consumer Opt-Out Charge. Even if the Company adjusts its acquisition strategy in the future, that does not change the fact that, without a Consumer Opt-Out Charge, the costs of the Company's existing resources that were procured to serve the departing load will be shifted to remaining customers.

Q. ICNU claims that PacifiCorp has failed to account for the value to cost-of-service customers of avoiding or delaying resource acquisitions due to the departure of direct access load.[7] How do you respond to this argument?

A. The Company's 2013 Integrated Resource Plan (IRP) has no new generation resources planned until 2024,[8] at which time the Company adds a 423 megawatt combined cycle combustion turbine. This is the last year of the 10-year valuation period for a customer that selected the Five-Year Program beginning in 2015 and would therefore create little to no capacity deferral value. There is no assurance that load reductions that arise from direct access would cause the 2024 resource to be deferred. In addition, the 2013 IRP Update, which will be filed with the Commission

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[6] Noble Solutions/100, Higgins/11; CNE/SENA/100, Lynch/6.
[7] ICNU/100, Schoenbeck/5.
[8] The Company's 2013 IRP can be found at http://www.pacificorp.com/es/irp.html.

on March 31, 2014, will show that no new generation resources are planned until 2027, which makes this claim moot.

SECTION X WILL CAUSE COST-SHIFTING

Q. What is the Stipulating Parties' theory discounting the impact of Section X of the 2010 Protocol?

A. While the Stipulating Parties concede that existing customers could be harmed by cost-shifting from departing direct access load because of Section X of the 2010 Protocol,[9] they urge the Commission to approve their proposal now based on the assumption that Section X will be revised before the first customers have completed the five-year transition period to direct access.

Q. What portions of Section X are relevant to this case?

A. Under the 2010 Protocol, the allocation of the costs and benefits of freed-up resources[10] is governed by three provisions in Section X:

1. Loads lost to Direct Access—Where the Company is required to continue to plan for the load of Direct Access Customers, such load will be included in Load-Based Dynamic Allocation Factors for all Resources.

2. Loads of customers permanently choosing Direct Access or permanently opting out of New Resources—Where the Company is no longer required to plan for the load of customers who permanently choose direct access or permanently opt out of New Resources, such loads will be included in Load-Based Dynamic Allocation Factors for all Existing Resources but will not be included in Load-Based Dynamic Allocation Factors for New Resources acquired after the election to permanently choose Direct Access or opt out of New Resources. An effective date for this process will be established at such time as customers permanently choose Direct Access or opt out, and this

[9] Stipulating Parties' Response to PacifiCorp 17 (attached as Exhibit PAC/403).
[10] The 2010 Protocol defines "Freed-Up Resources as "Resources made available to the Company as a result of its customers becoming Direct Access Customers." See Appendix A of the 2010 Protocol.

process will be implemented under the guidance of the MSP Standing Committee.

3. In each State with Direct Access Customers, an additional step will take place for ratemaking purposes to establish a value or cost (which could include a transfer of Freed-Up Resources between customer classes within a State) resulting from the departure of the departing load; other States do not implement the second step.[11]

Q. Please provide a brief history of Section X of the 2010 Protocol.

A. The history of Section X shows that it was drafted to respond to the position of Oregon Commission Staff, CUB, and ICNU (the Oregon Coalition) regarding Oregon direct access in the Revised PacifiCorp Inter-Jurisdictional Cost Allocation Protocol (Revised Protocol). As originally proposed by PacifiCorp, the Revised Protocol allocated the costs of all resources to Oregon on the basis of Oregon's load, which included the load of direct access customers.[12] The Oregon Coalition argued that this approach was inconsistent with Oregon direct access policy because "it is likely that at least some direct access consumers will leave the system permanently."[13] To hold remaining customers harmless, "[w]hen a consumer chooses to leave the system permanently through direct access, the consumer is responsible for the stranded cost or benefits at the time the consumer leaves the system."[14] The Oregon Coalition concluded that the appropriate method for handling direct access loads was as follows:

1. Include in inter-jurisdictional allocations the loads of direct access consumers for those generation resources and

[11] 2010 Protocol at Section X.
[12] Docket UM 1050, PPL/202, Kelly/9-10 (May 21, 2004).
[13] Docket UM 1050, Staff/102, Hellman/60 (July 2, 2004) (attached as Exhibit PAC/404). Staff's testimony in support of the Revised Protocol included a document call the "Oregon Coalition Issues Paper and Alternative Proposals," which is the source of this position statement. Docket UM 1050, Staff/102, Hellman/51-79 (July 2, 2004).
[14] Docket UM 1050, Staff/102, Hellman/60 (July 2, 2004).

contractual obligations, for the life of these resources, that were in place when either the direct access consumer left the system or when the consumer notified the company that it no longer wanted the utility to plan to serve its loads; and

2. Exclude direct access loads for purposes of allocating costs of new resource and power purchase commitments made subsequent to the time the direct access consumer permanently left the PacifiCorp generation system or notified the Company to no longer plan to serve the consumer.[15]

The Oregon Coalition's position is reflected in the final version of Section X.

In support of the Revised Protocol, Staff witness Dr. Marc Hellman testified that it "[r]esolves direct access issues from an inter-jurisdictional standpoint consistent with Oregon direct access goals and objectives."[16] Elaborating on this point, Dr. Hellman reiterated that the Revised Protocol provides for two types of direct access:

> [The Revised Protocol] continues to assign to states existing resources and resources that were planned to meet direct access eligible loads. In that way, the benefits and costs of those resources are retained by Oregon, including the stranded costs or benefits associated with the resources. In addition, for resources added after loads choose direct access, and assuming the resources were not planned to meet those loads, the direct access loads are not counted for multistate allocation purposes. That is, for each direct access customer there are essentially two sets of Oregon loads applicable to the interstate jurisdictional allocation, and each is resource specific. The [Revised Protocol] also provides Oregon flexibility to allow customers to notify the company that it should no longer plan to meet the customer's loads. This is a "Don't plan for me" concept. The treatment of loads and direct access is a change in allocation methods specifically to address the direct access issues.[17]

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[15] Docket UM 1050, Staff/102, Hellman/61 (July 2, 2004).
[16] Docket UM 1050, Staff/100, Hellman/10 (July 2, 2004).
[17] Docket UM 1050, Staff/100, Hellman/26 (July 2, 2004).

The Commission approved the Revised Protocol in Order No. 05-021.[18] The Commission agreed with Staff that the Revised Protocol "enhance[d] Oregon's ability to implement direct access" and was therefore in the public interest.[19] The Revised Protocol was amended by the 2010 Protocol, which was approved by the Commission in Order No. 11-244.[20] The 2010 Protocol included no changes to the Revised Protocol's direct access terms. No party raised objections to Section X in the Commission's review of the 2010 Protocol.

Q. Please explain how Section X allocates Oregon direct access transition costs or benefits.

A. Section X of the 2010 Protocol allows for direct access customers to either: (1) permanently opt-out, thereby relieving PacifiCorp of its obligation to plan to serve these customers; or (2) choose direct access for a shorter-term with the understanding that PacifiCorp will still be required to plan for and serve that direct access load in the future. In either case, "Existing Resources," *i.e.*, "Resources whose costs were committed to prior to Direct Access Customers making an election to permanently forego being served by the Company at a cost-of-service rate,"[21] will continue to be allocated to Oregon customers based on the inclusion of the direct access load. If customers make a "permanent" election for direct access, New Resources are allocated without consideration of the loads of these departing direct access customers.

[18] *In the Matter of PacifiCorp* Request *to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket UM 1050, Order No. 05-021 (Jan. 12, 2005).
[19] *Id.* at 8.
[20] *In the* Matter *of PacifiCorp, dba Pacific Power, Petition for Approval of Amendments to Revised Protocol Allocation Methodology*, Docket UM 1050, Order No. 11-244 (July 5, 2011).
[21] Order No. 05-021, Appendix A of Revised Protocol.

Q. Please explain how Section X would apply to the Five-Year Program.

A. Oregon's share of the Company's system load will include the loads of direct access customers under the Five-Year Program for allocating the costs of existing generation resources. It is possible that the costs of new resources will be allocated in the same manner because, under the Company's modified Five-Year Program, customers will have the option to return to cost-based supply service after notice, which could be considered inconsistent with a "permanent" opt-out for purposes of Section X.

If this is the case, Oregon customers will potentially pay for the costs of the resources (both existing and new) that are necessary to serve direct access loads even if those resources are not actually serving those loads. Because the costs of resources under this scenario will be allocated to Oregon as if the direct access load was being served by that resource, the costs of that resource allocable to the now-absent direct access load will be shifted to remaining Oregon customers.

Q. How does the Consumer Opt-Out Charge for the Five-Year Program offset cost-shifting under Section X?

A. The Stipulating Parties concede that the costs allocated to Oregon for departing direct access load under Section X are transition costs under OAR 860-0038-0005(68).[22] Unless the departing direct access customers cover these costs in advance through the Consumer Opt-Out Charge, they will be shifted to other Oregon customers. This is true even if new customers ultimately replace the direct access load because the 2010 Protocol has no provision to remove the direct access load from the total Oregon load used to allocate costs.

[22] Stipulating Parties' Response to PacifiCorp 20 (attached as Exhibit PAC/405).

Q. The Stipulating Parties refer to Section X as "obscure" and "outdated." Please respond.

A. The 2010 Protocol, including the Section X provisions proposed by Dr. Hellman and supported by the Oregon Coalition, was approved by the Commission in July 2011 in Order No. 11-244. There have been no material changes in Oregon direct access laws or regulations since that date that would render Section X outdated.

Q. The Stipulating Parties assert that Staff has proposed changes to Section X in the current Multi-State Process (MSP), so it should not be an impediment to adoption of their proposal. Does PacifiCorp agree with this position?

A. No. Oregon law precludes cost-shifting, and cost-shifting will occur under the Five-Year Program given the current operation of Section X. Staff's proposed changes to Section X in the MSP recognize this fact. But Staff cannot unilaterally revise Section X. Given the concerns that other states may have over the shifting of Oregon direct access transition costs to other states, resolution of this issue may be complex and the exact terms of a new Section X are currently unknowable. Unless and until Section X is changed in the MSP, the Company's Five-Year Program should include a Consumer Opt-Out Charge to protect customers from Section X's cost-shifting. Otherwise, the Company might be in the position of needing to honor customers' opt-out elections even though these elections clearly cause unwarranted cost-shifting.

Q. The Stipulating Parties point to the expiration of the 2010 Protocol in 2016. Will this resolve the Section X cost-shifting issue?

A. No. Consistent with the stipulation approving the 2010 Protocol, "absent formal action by the Commission to adopt an alternate allocation methodology for Oregon," the Company will revert to the Revised Protocol upon expiration of the 2010 Protocol.[23] As noted above, Section X is also a part of the Revised Protocol.

Q. The Stipulating Parties claim that Section X unfairly treats departing direct access load differently from all other departing load. Please respond.

A. This is one of the arguments that supports reexamination of Section X in the MSP. The counter-argument is that Oregon law treats departing direct access customers differently than all other departing customers by requiring the payment of transition charges or the receipt of transition benefits. But ultimately, the resolution of Section X is outside the scope of this docket. The question in this case is whether the Company's Five-Year Program should be designed to take Section X into account as long as it remains operative (the Company's approach) or whether a particular revision to Section X should be assumed in the design of the Five-Year Program (the Stipulating Parties' approach).

Q. Could adopting a direct access program that assumes changes to Section X before these changes are fully examined and resolved in the MSP have unintended consequences in Oregon?

A. Yes. Section X governs all direct access programs in all states, not just Oregon. If another state implements a direct access program and very large customers (*i.e.*, single loads in the range of 50 to 100 MW) suddenly leave PacifiCorp's system, then Section X could provide important protection to Oregon against the shifting of costs from the other state. Because Oregon may have more to lose than to gain from the modification of Section X, adoption of the Stipulating Parties' proposal could be adverse to Oregon's interests in the long run.

[23] Order No. 11-244, Appendix A at 4.

PGE'S PROGRAM IS INAPPROPRIATE FOR PACIFICORP

Q. The Stipulating Parties oppose the Consumer Opt-Out Charge on the basis that PGE's five-year opt-out program does not include such a charge. What is your response to this argument?

A. PGE and PacifiCorp are not similarly situated. PGE's stipulated approach to its five-year opt-out program is not precedent for PacifiCorp's Five-Year Program, especially because the Commission has never issued an order explicitly addressing any of the issues raised in this case. In fact, in Order No. 12-500, the Commission specifically recognized that PacifiCorp could "tailor its program to fit its circumstances" and required that PacifiCorp's program "be designed to protect other customers from cost-shifting."[24]

Q. Can you provide your understanding of the origins of PGE's five-year opt out program, beginning with the first proposals for such a program in Oregon?

A. Yes. In 2002, the Commission opened docket AR 441 to address a permanent opt-out proposal from ICNU. The Commission consolidated that docket with docket AR 417, and ultimately closed both dockets without specifically addressing ICNU's proposal. In an MSP white paper authored by Oregon Staff member Dr. Hellman in May 2002, he described ICNU's opt-out proposal in the following question and answer:

> *Are the parties in Oregon discussing sidestepping the transition charge and credit calculations to "jump start" direct access?*
>
> Yes. Parties are discussing the possibility of allowing large consumers the opportunity to choose direct access, and at the same time waive any right to return to cost of service rates. For such consumers, there would be no transition charge or

[24] *In the Matter of Public Utility Commission of Oregon Investigation of Issues Relating to Direct Access*, Docket UM 1587, Order No. 12-500 at 9 (Dec, 30, 2012).

> credit. In effect, the one-time market value of the utility's resource is deemed to equal the cost of the resources. It is unclear whether the Commission has statutory authority to accept a customers' waiver of the cost-of-service requirement prior to July 2003. Parties are pursuing this option to: 1) avoid the one-time valuation process; 2) allow some consumers to choose direct access; and 3) because the current market price strips appear to be close to the long-term costs of utility resources. Parties also believe that in the short-term, if consumers choose direct access, the remaining consumers may not face significant rate increases or decreases, as these remaining consumers receive the costs and benefits of the plants.[25]

Q. Why is this early history important?

A. When ICNU first proposed the permanent opt-out, the premise was that transition costs were at or near zero, which was a reasonable assumption at the time since the market value of existing resources was near their embedded cost as noted by Dr. Hellman above. This is very different from PacifiCorp's current situation where transition costs over 10 years are $38 million due to the fact that the embedded cost of existing resources exceeds the market value of these resources.

Q. When did the Commission first adopt PGE's five-year opt-out program?

A. In October 2002 in Advice 02-17. PGE described the origin of the permanent opt-out in its Reply Comments in docket UM 1587:

> PGE first offered the permanent opt-out in 2002 effective for 2003 in response to a proposal made by the Industrial Customers of Northwest Utilities (ICNU) for a one-time permanent opt-out with no transition adjustments for customers whose load exceeded one average megawatt. This ICNU proposal was discussed extensively in OPUC docket AR 441.[26]

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[25] Docket UM 1050, Staff/102, Hellman/10 (July 2, 2004) (Marc Hellman, Draft "White Paper" De-Regulation/Open Access at 8 (May 10, 2002)), attached as Exhibit PAC/404.
[26] PGE Reply Comments in Docket UM 1587 at 3 (Sept. 14, 2012).

Q. Did PGE agree to maintain the five-year opt-out program for five years as a part of the stipulation permitting PGE to become a stand-alone company?

A. Yes. On September 1, 2005, PGE filed a stipulation in dockets UM 1206/UF 4218, seeking approval to convert PGE from Enron ownership into a stand-alone company. In that stipulation, PGE agreed to offer its five-year opt-out for at least five more years, through 2010. The Commission approved the stipulation in Order No. 05-1250.[27]

Q. Is PGE's current five-year program the result of additional stipulations in PGE dockets UE 236 and UE 262?

A. Yes.[28]

Q. In approving PGE's five-year opt-out programs, has the Commission ever issued an order specifically addressing the issues raised in this case?

A. No. Presumably because PGE's five-year opt-out programs resulted from stipulations that included PGE and all other interested parties, the Commission did not address the issues of cost-shifting or full payment of transition costs in its past orders. And these issues were not implicated in PGE's cases because PGE is not a multi-state utility and they have had a very different load and resource balance in Oregon than PacifiCorp. Unlike PacifiCorp, to the best of my knowledge PGE has not indicated they have any transition costs beyond five years. For this reason, the Commission's prior approval of PGE's five-year opt-out does not support the Stipulating Parties' objection to the Consumer Opt-Out Charge in PacifiCorp's Five-Year Program.

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[27] *In the Matter of Portland General Electric Company*, Docket UF 4218/UM 1206, Order No. 05-1250 (Dec. 14, 2005).

[28] *See In the* Matter *of Public Utility of Oregon Investigation into the Changes Proposed for the 3 and 5 year Cost of Service Opt-out Program for Large Non-Residential Customers*, Docket UE 236, Order No. 12-057 (Feb. 23, 2012); *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 262, Order No. 13-459 at 10 (Dec. 9, 2013).

Q. Did the Commission need to consider multi-state allocation issues with PGE?

A. No. Consideration of multi-state allocation issues is not relevant to PGE, but it is a significant issue for PacifiCorp.

MODIFICATIONS TO TRANSITION ADJUSTMENT CALCULATION

Q. What modifications did the Company make to its transition adjustment calculation in the Five-Year Program?

A. The Company made three modifications to its calculation of the transition adjustment. First, the Company will calculate the value of freed-up energy using the same methodology that is used to calculate the value of freed-up energy for the annual TAM under Schedule 294. Second, the Company will adopt the Stipulating Parties' proposal to eliminate the HLH/LLH split. Third, the Company will assume the incremental departure of 50 aMW of direct access load when calculating the transition adjustment. The Company applied these changes to both the calculation of the transition adjustment and the calculation of the Consumer Opt-Out Charge.

Q. Please describe the first modification regarding the value of freed-up energy.

A. The Company's original proposal calculated the transition adjustment as the difference between two GRID runs, one with the direct access load and one without. The Stipulating Parties' objected to this approach and proposed instead to calculate the transition adjustment in the same way that the Schedule 294 and 295 transition adjustments are calculated—with a post-GRID adjustment that blends forecast market prices with the GRID results. For consistency between Schedules 294, 295, and 296, the Company agrees to incorporate this modification into the calculation of the transition adjustment.

Q. Please describe the modification regarding the elimination of the HLH/LLH split.

A. The Company originally proposed to differentiate the transition adjustment between HLH and LLH. The Stipulating Parties argued that the Company's proposal would provide economically inappropriate price signals that would preferentially treat HLH as opposed to LLH. Based on the concerns expressed by the Stipulating Parties, the Company agrees to incorporate this modification into the calculation of the transition adjustment.

Q. Please describe the modification regarding the assumed direct access loads.

A. Originally, the Company proposed that the calculation of the transition adjustment would assume 175 aMW of departing load. In response to the Stipulating Parties' proposal, the Company agrees to modify this figure to assume only 50 aMW of incremental direct access load when calculating the transition adjustment. This amount is more consistent with the 25 aMW of assumed direct access load used to calculate the Schedule 294 and 295 transition adjustments.

REJECTION OF OTHER TRANSITION ADJUSTMENT CHANGE

Q. What proposed change to the calculation of the transition adjustment does PacifiCorp reject?

A. PacifiCorp rejects the Stipulating Parties' recommendation to include a credit in the calculation for the value of freed-up transmission.

Q. Please describe the Stipulating Parties' proposal to include a credit in the transition adjustment for the value of freed-up transmission.

A. The Stipulating Parties recommend that the transition adjustment include a credit based on the BPA transmission that is supposedly "freed-up" when direct access loads leave PacifiCorp's system.

Q. Has the Commission addressed this proposal before?

A. Yes. The Commission has rejected this exact proposal in the Company's last two TAM proceedings.[29] In the 2013 TAM, Order No. 12-409, the Commission found that "compelling evidence was not presented that Pacific Power is able to resell BPA transmission rights due to direct access." This finding was affirmed on reconsideration.[30] In the 2014 TAM, Order No. 13-387, the Commission again found "no compelling reason to depart from our precedent."[31]

Q. Is it still true that the Company does not obtain value from freed-up transmission services as a result of losing load to direct access?

A. Yes. Depending on the location of the lost load and the existing transmission arrangements with BPA and the Company's transmission function, there is little to no opportunity to realize the value of freed-up transmission with BPA. In addition, the Company may need to acquire additional transmission to deliver freed-up generation to market in order to realize the transition adjustment determined for the lost load. These additional costs are not reflected in the Company's calculation of the transition adjustment. In addition, even if transmission capacity was "freed-up" as the Stipulating Parties claim, the Company cannot necessarily sell the transmission rights if they are network rights.

[29] Order No. 12-409 at 17 (affirmed on reconsideration Order No. 13-008); Order No. 13-387 at 13-14.
[30] Order No. 13-008.
[31] Order No. 13-387 at 14.

Q. The Stipulating Parties claim that PacifiCorp will have no need to maintain BPA transmission rights because once the customers elects to participate in the Five-Year Program, the Company will no longer have to plan to serve that customer. How do you respond to this point?

A. Given the modification allowing customers to return to PacifiCorp's cost-based supply with a four-year notice, the Five-Year Program now provides only a non-binding option for customers to make a permanent direct access election. Additionally, if the contractual and scheduling arrangements of the new provider fail at any time, for any period of time, the Company must retain its wheeling arrangements to cover this load as the provider of last resort. PacifiCorp must maintain sufficient long-term transmission to address these contingencies.

Q. The Stipulating Parties also observe that PGE's program includes a BPA transmission credit. Is that relevant to the calculation of PacifiCorp's transition adjustment?

A. No. When the Commission last rejected this adjustment just last year, the Commission specifically concluded that comparisons to PGE's system fail to account for the important differences between PGE's and PacifiCorp's systems.[32]

Q. Did the Stipulating Parties address any of these issues in their testimony?

A. No. This omission is significant considering the Commission's previous orders on this issue.

[32] Order No. 13-387 at 13-14.

Q. The Stipulating Parties also claim that the lack of a transmission credit constitutes a "structural impediment" to the development of direct access. Is this so-called "structural impediment" relevant to the appropriate determination of direct access rates and transition credits?

A. No. As described in OAR 860-038-0160(2)(b): "The direct access rates must exclude electric company costs that are avoided when a consumer chooses to be served under the direct access rate option." Direct access rates are intended to compensate for electric company costs, not for costs that might be incurred by an Energy Service Supplier.

USE OF MARKET PRICES IN LIEU OF GRID TO DETERMINE TRANSITION ADJUSTMENT

Q. Please describe Noble Solutions and Wal-Mart's proposal to calculate the transition adjustment outside of the Company's GRID dispatch model.[33]

A. These parties originally recommended that the transition adjustment be calculated using an average of forecast market prices at the California-Oregon Border (COB) and Mid-Columbia (Mid-C), rather than using GRID.

Q. Do the Stipulating Parties support this proposal?

A. No. The Stipulating Parties testify that "it would be preferable for participating customers if the Schedule 296 transition adjustment were based solely on uncapped market prices, [but] the Stipulating parties are willing to agree to an adjustment for PacifiCorp's thermal generation costs consistent with prior settlements."[34]

[33] Noble Solutions/100, Higgins/5; Walmart/100, Chriss/12.
[34] Stipulating Parties/100, Higgins, Compton, Schoenbeck, Chriss, Lynch/13.

Q. Do you agree with the Stipulating Parties statement that the use of GRID to calculate the transition adjustment is the result of "prior settlements?"

A. No. In fact, like the BPA transmission credit proposal, Noble Solutions raised this exact argument in the 2013 TAM, and the Commission soundly rejected it, concluding: "We agree with Pacific Power that we have addressed the use of GRID to calculate the transition adjustment in previous dockets, and we decline to adopt Noble Solutions' proposed change in this docket."[35] The Commission found that in PacifiCorp's case, the use of only forecast market prices "may not accurately reflect an actual estimate of direct access costs, because Pacific Power's utility operations are complex and multidimensional."[36]

Q. Has the Commission previously provided policy direction applicable to the issue of simply using market prices to value freed-up energy?

A. Yes. The Commission addressed this issue in dockets UM 1081 and UE 179. In docket UM 1081, the Commission adopted an interim transition adjustment based on market prices for the near-term, but asked parties to work together to find a long-term solution. Subsequently, in docket UE 179, the Commission rejected the market price approach in favor of using differential GRID runs to value the loss of the direct access load.[37] In that case, Staff recommended the use of GRID and testified that a GRID-based transition adjustment "offers the most precise and accurate accounting of the impact that direct access is likely to have on PacifiCorp's operations, costs and revenues[.]"[38] The Commission found that using the differential GRID run approach

[35] Order No. 13-387 at 12-13.
[36] Order No. 13-387 at 12-13 (internal quotations omitted).
[37] Order No. 04-516 at 10.
[38] Order No. 04-516 at 5.

to determine the transition adjustment proposed by PacifiCorp most closely met the requirements established in Order No. 04-516 in docket UM 1081.[39] The Commission went on to say, "[t]he purpose of the TAM is not to promote direct access, as ICNU would have us do. Rather, the TAM is to capture costs associated with direct access, and prevent unwarranted cost shifting."[40]

Q. Is the current transition adjustment calculation based solely on the GRID valuation of the generation freed-up by departing direct access customers?

A. No. The Company calculates the transition adjustment by first running GRID with the direct access load removed to determine the system response to lower load. Changes in market transactions are valued at average market prices, and changes in thermal generation are valued at the simple average of prices at the Mid-C and COB markets and the cost of thermal generation.

Table 1 below demonstrates the value of the sample transition adjustment for Schedule 48 included with the Company's initial filing under various scenarios. As shown in Table 1, the current method of calculating the transition adjustment includes a significantly higher weighting of market value and lower weighting of generation than is justified by the GRID results. The overall transition adjustment value under the current method is significantly higher than the value as determined in GRID.

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[39] Order No. 05-1050 at 21.
[40] Order No. 05-1050 at 21.

Table 1—Annual Transition Credit/(Charge) Value ($M) and Market Weighting (%)

	Annual Transition Credit/(Charge) Value ($M)			Market Weighting		
Method	**HLH**	**LLH**	**Total**	**HLH**	**LLH**	**Total**
GRID Only Blend	1.1	(0.6)	0.5	96%	53%	77%
Filed Blend	1.3	0.6	2.0	99%	84%	92%
Noble Solutions Proposal	2.0	0.4	2.4	100%	100%	100%

Q. Noble Solutions recommends the use of a 50/50 blend of COB and Mid-C market prices. Does a 50/50 blend of COB and Mid-C market prices correspond to the proportional change in market transactions by market as determined by GRID?

A. No. As shown in Table 2 below, the GRID results used as inputs to the example transition credit filed in this case include quantities of market transactions on the east side of the Company's system and somewhat fewer transactions at COB than in Noble Solutions' proposal. The filed method uses COB and Mid-C prices to value two-thirds of the generation impact, so the weightings of these markets are somewhat overstated compared to the actual GRID result.

Table 2 — Market and Generation Weighting Detail (%)

Resource	GRID Only Blend	Filed Blend	Noble Solutions Proposal
COB	18%	26%	50%
Four Corners	3%	3%	0%
Mead	1%	1%	0%
Mid Columbia	36%	44%	50%
Mona	12%	12%	0%
NOB	4%	4%	0%
Palo Verde	3%	3%	0%
Market Total	77%	92%	100%
Generation	23%	8%	0%

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 267
Exhibit PAC/401
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Gregory N. Duvall

Updated Example Calculation of Schedule 296 Transition Adjustments and Customer Opt-Out Charge

March 2014

Exhibit PAC 401
Schedule 296 - Five Year Cost of Service Opt-Out Program
Customer Opt Out Charge ($/MWh)

Schedule 30

	HLH	LLH	Flat
Filed Method - 20 Year Forecast	$15.63	$30.02	$21.64
Updated (March 2014)			$8.67

Schedule 47/48

	HLH	LLH	Flat
Filed Method - 20 Year Forecast	$11.49	$25.41	$17.30
Updated (March 2014)			$6.18

Exhibit PAC 401
Schedule 30
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment	Schedule 200 - Base Supply	Customer Opt Out Charge
	(a)	(b)	(c)	(d)	(e)
	(a)=Sch Avg		(c)=(a)-(b)	(d)=Sch Avg	=23.32-14.65
2015	$27.57	$34.59	($7.02) -	$28.95 -	$8.67
2016	$28.18	$34.80	($6.62) -	$29.50 -	$8.67
2017	$28.14	$35.51	($7.37) -	$30.06 -	$8.67
2018	$28.53	$37.42	($8.89) -	$30.63 -	$8.67
2019	$28.81	$39.50	($10.69) -	$31.21 -	$8.67
2020	$29.85	$44.45	($14.60)	$31.80	
2021	$32.21	$49.52	($17.31)	$32.40	
2022	$32.90	$56.67	($23.77)	$33.02	
2023	$33.70	$58.09	($24.39)	$33.65	
2024	$34.07	$59.49	($25.42)	$34.29	
10-Year Net Present Value (1)			($59.83)	$95.23	$35.40
5-year Nominal Levelized Payment			($14.65)	$23.32	$8.67

Notes:

(1) 2015 through 2024 using a 7.154% Discount Rate

(2) Losses at 8.56%

Exhibit PAC 401
Schedule 47/48
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=21.73-15.55
2015	$26.08	$34.28	($8.20)	-	$26.98	-	$6.18
2016	$26.66	$34.48	($7.82)	-	$27.49	-	$6.18
2017	$26.62	$35.19	($8.57)	-	$28.01	-	$6.18
2018	$26.99	$37.08	($10.09)	-	$28.54	-	$6.18
2019	$27.26	$39.15	($11.89)	-	$29.08	-	$6.18
2020	$28.24	$44.05		($15.81)		$29.63	
2021	$30.48	$49.08		($18.60)		$30.19	
2022	$31.13	$56.15		($25.02)		$30.76	
2023	$31.89	$57.57		($25.68)		$31.34	
2024	$32.24	$58.95		($26.71)		$31.94	
10-Year Net Present Value (1)				($63.48)		$88.72	$25.23
5-year Nominal Levelized Payment				($15.55)		$21.73	$6.18

Notes:
(1) 2015 through 2024 using a 7.154% Discount Rate
(2) Losses at 7.58%

Docket No. UE 267
Exhibit PAC/402
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Gregory N. Duvall

Estimated Cost Shift for Five Year Program

March 2014

Exhibit PAC 402

Schedule 296 Potential Cost Shift
Assuming Average Market Prices for Electricity and Natural Gas

Year	Schedule 201 - Net Power Costs in Rates ($/MWh) (a) (a)=Sch Avg	NPC Impact of 50 aMW Leaving System ($/MWh) (b)	Transition Adjustment ($/MWh) (c) (c)=(a)-(b)	Schedule 200 - Base Supply ($/MWh) (d) (d)=Sch Avg	Net Impact of Customer Exiting ($/MWh) (e) (e)=(c)+(d)	Shifted Costs ($ Millions) (1) (f) (f)=(e)x 175 aMW
2015	$26.08	$34.37	($8.29)	$26.98	$18.69	$0.00
2016	$26.66	$34.58	($7.92)	$27.49	$19.57	$0.00
2017	$26.62	$35.29	($8.67)	$28.01	$19.34	$0.00
2018	$26.99	$37.19	($10.20)	$28.54	$18.34	$0.00
2019	$27.26	$39.26	($12.00)	$29.08	$17.08	$0.00
2020	$28.24	$44.17	($15.93)	$29.63	$13.70	$21.06
2021	$30.48	$49.21	($18.73)	$30.19	$11.46	$17.56
2022	$31.13	$56.31	($25.18)	$30.76	$5.58	$8.55
2023	$31.89	$57.73	($25.84)	$31.34	$5.50	$8.44
2024	$32.24	$59.12	($26.88)	$31.94	$5.06	$7.78

10-Year Net Present Value (2015-2024) 7.154% Discount Rate $38.09

(1) 175 average megawatts of participation. Shifted costs quantified for years 6 through 10.

Docket No. UE 267
Exhibit PAC/403
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Gregory N. Duvall

Stipulating Parties' Response to PacifiCorp Data Request 17

March 2014

PACIFICORP DATA REQUEST NO. 17 TO STIPULATING PARTIES:

See page 23, line 18 to page 24, line 6 of the Joint Testimony. Please explain how system load growth prevents the shifting of transition costs (as defined in OAR 860-038-0005(68)) from departing Oregon customers to other customers. If the explanation involves allocating transition costs of departing load to new customers in other states, please explain how that is possible in light of Section X of the 2010 Protocol.

RESPONSE TO PACFICORP DATA REQUEST NO. 17:

Please refer to the Stipulating Parties' Joint Testimony at pages 9-11, and the Stipulating Parties' response to PacifiCorp data request no. 16. The Stipulating Parties' position is that there will be no unrecovered uneconomic utility investments that will be allocated to non-direct access customers in Oregon or other PacifiCorp states.

System load growth replaces the loads that are departing utility generation services. In this way, other customers of PacifiCorp are not harmed by the departure of direct access load. If Section X continues in its present form, existing customers will be responsible for the fixed generation costs and could be harmed. This is the basis for Oregon Staff raising the issue of amending Section X to the Standing Committee for any follow-on agreement to the 2010 Protocol.

Docket No. UE 267
Exhibit PAC/404
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Gregory N. Duvall

Staff Exhibit 102, Docket UM 1050 (July 2, 2004)

March 2014

CASE: UM 1050
WITNESS: Dr. Marc M. Hellman

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 102

Exhibits in Support of Direct Testimony and Background Materials

July 2, 2004

May 10, 2002

To: Robert Hanfling
Special Master, PacifiCorp Multi-State Process.

From: Bob Jenks,
Executive Director, Citizens' Utility Board of Oregon

Re: Conservation investment and allocation problems

Oregon has implemented a 3% Public Purposes Charge that funds energy efficiency, low-income weatherization, and renewable energy programs. Each residential and commercial customer pays this charge. Industrial customers have the option of paying it or investing their portion in their own plant and equipment (self-direction). The result is that PacifiCorp customers in Oregon will be investing more than $200 million in demand-side management programs over the next 10 years. We believe this is significantly higher than the investment commitments made by other states.

But this issue goes beyond Oregon. Rather than encouraging states to make the least cost investments, the current allocation system rewards states if their load grows relative to the system and penalizes states if their load decreases relative to the system. This creates two allocation problems: the general rate case allocation problem and the in-between rate case allocation problem.

1. The general rate case allocation problem. PacifiCorp allocates its power costs as a system. As conservation programs reduce load, the Company reduces its need to invest in new power sources (whether base load, peaker or purchases). The problem occurs because the new power sources are more expensive than the average cost of existing generation. We front load the costs of new generation when we rate base it, so new generation will almost always be more expensive than generation that is partially amortized. In addition, PacifiCorp's portfolio of power resources include some inexpensive hydro and coal resources that cannot be duplicated in today's world. If Oregon invests in conservation, our share of the Company's overall power costs goes down. If these programs reduced Oregon's share of the system from 29% to 26%, a general rate case would reflect this and Oregon would pay 26% of the average cost of power, yet the system would save the cost of more expensive new power sources. Therefore, the state that conserves sees a reduction in average power costs even though the Company avoids the cost of new more expensive power sources.

This allocation creates a disincentive for states to make cost-effective conservation investments. As an example assume that the cost of new resources is 5 cents/kWh and the average cost of existing resources is 3 cents/kWh. The overall system (all states) should invest in any conservation program that costs less than 5 cents/kWh. But if states only receive a credit from the Company of 3 cents/kWh for their investment, then much of the cost-effective conservation will not be acquired. In addition this problem is increased because load increases create the opposite effect of load decreases. If a state has load growth that is increasing at a greater rate than the system, then it is increasing the system costs at 5 cents/kWh, but PacifiCorp charges that state the average cost or 3 cents/kWh, and all other states make up the difference. In other words, the system includes subsidies for states with high load growth, and penalizes states with significant load reduction programs.

2. The in-between rate case problem. Between ratecases, customers can still see rates change due to increases in power costs (deferrals and power cost adjustments). In these cases, the Company allocates costs between states based on the last rate case, so a state will see not see the benefits of conservation that has happened since the last rate case. During the recent power crisis, Oregon's Governor led an aggressive campaign calling on Oregon residents and businesses to conserve. Oregonians responded with both behavioral changes and financial commitments to conservation investments. However, PacifiCorp continued to pursue a deferral based on historic allocation of load (assigning 1/3rd of costs to Oregon). In this case Oregon's conservation was saving the system the high cost of market purchases, but Oregon only received 1/3rd of the savings from our own conservation efforts.

The current system is flawed. Load growth is subsidized, but load reduction is penalized. In an ideal system those that cause costs would pay for those costs and those that create savings would receive those savings.

DRAFT "WHITE PAPER"
DE-REGULATION/OPEN ACCESS

Author – Marc Hellman[1]
Public Utility Commission of Oregon

Laws enacted by the Oregon legislature to move towards a more competitive framework for the sale of electric power became effective March 1, 2002. Oregon's restructuring laws are designed to give consumers more options while encouraging the development of a competitive energy market. Under Oregon's new laws, utilities such as PacifiCorp will continue to deliver power, and will maintain the safety and reliability of the poles and wires that deliver power. However, consumers of the two largest investor-owned utilities in Oregon, Portland General Electric Company (PGE) and PacifiCorp,[2] may elect to receive power pursuant to different "options", which include the companies' standard offer, "portfolio options", or direct access.

Two pieces of legislation establish the framework for Oregon's new direction in the supply and delivery of electric power: Senate Bill 1149, signed into law in July of 1999, and House Bill 3633, which was passed by the 2001 Legislature. SB 1149 requires the state's largest investor-owned utilities to change the way they conduct business. This law received broad-based support including the support of the Oregon Public Utility Commission, the Citizens' Utility Board, Industrial Consumers of Northwest Utilities and Associated Oregon Industries. PacifiCorp, however, was not supportive of the bill.

In 2001, the Oregon legislature amended SB 1149 by enacting HB 3633. HB 3633 amended SB 1149 in two major areas. First, HB 3633 delayed the effective date of SB 1149 for five months, delaying dates such as the deadline for providing direct access, from October 1, 2001, to March 1, 2002. Second, SB 1149 required both PGE and PacifiCorp to offer all consumers a cost of service rate. However, under HB 3633, the Commission will have authority, after July 1, 2003, to order that PGE and PacifiCorp discontinue the offering of a cost of service rate to large non-residential consumers.

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[1] This report was prepared by using documents available on the OPUC website as well as a June 2001, legislative report prepared by OPUC staff. The author of this paper remains solely responsible for its contents and expressed opinions.

[2] The new legislation only applies to electric utilities of a certain size, and does not apply to the third investor-owned utility operating in Oregon, Idaho Power Company, which has a relatively small load in Oregon. PGE and PacifiCorp together serve nearly 75% of all electric loads in Oregon. In the year 2000, PGE had nearly 750,000 consumers with loads of roughly 2300 aMW. PacifiCorp, for the same time period, served nearly 500,000 Oregon retail consumers and the load averaged 1800 aMW.

The following is a brief description of the service options currently provided by PGE and PacifiCorp under the new legislation:

- **Direct Access Option** (available to all nonresidential consumers)

  The direct access option allows a consumer to purchase electricity and related services in the competitive market from an electricity service supplier (ESS).

- **Standard Offer Option** (available to all nonresidential consumers)

  This option allows consumers to purchase energy from PacifiCorp based on daily rates.

- **Portfolio Option** (available to residential and small (<30 kW) non residential consumers)

  This option allows consumers to choose from a set of product and pricing options provided by PacifiCorp. At a minimum, one option must reflect renewable energy resources and another must be a market-based option. There can be more than one option for each of the above, but least one renewable energy resource product must contain significant new resources.

- **Cost-of-service Rate Option**

  This option allows consumers to purchase electricity at a rate based on PacifiCorp's costs, using the traditional methods of determining and allocating costs.

The charts below displays the choices made by consumers of PGE and PacifiCorp as of April 2002, regarding these options:

Portfolio Choices by Residential and Small Nonresidential (April 2002)

Portfolio Options*	PGE	% Participation	PP&L	% Participation
Fixed Renewable	5032	0.7%	3820	0.8%
Renewable Usage	4576	0.6%	3462	0.7%
Habitat	2576	0.3%	988	0.2%
Time-of-use	1785	0.2%	466	0.1%
Seasonal Flux	N/A		1487	0.3%
Total	13969	1.9%	10223	2.1%
Eligible Consumers	722066		486000	

* Available to residential and small nonresidential consumers (<30kW). Consumers may, in certain circumstances, choose more than one option.

Customer Choices
Direct Access and Standard Offer Service

Certified Electricity Service Suppliers: 6
Registered Electricity Service Aggregators: 5

Nonresidential Customer Choices (based on load)

	PGE	PacifiCorp
Cost of Service	91%	99.9%
Market Options	9%	0.1%
Direct Access	0.0%	0.0%

KEY QUESTIONS THAT MAY BE OF INTEREST TO MSP PARTICIPANTS

Does Oregon's restructuring legislation require PacifiCorp to sell resources?

No. To carry out its obligation to provide consumers a cost-of-service rate option, PacifiCorp must develop a resource plan identifying resources that should be retained in revenue requirement to serve Oregon load. PacifiCorp's loads and resources are roughly in balance. If all classes of consumers continue to be eligible for a cost-of-service rate, all of PacifiCorp's resources would very likely remain in its revenue requirement.

Is it possible that implementation of SB 1149 will cause PacifiCorp to want to sell some resources?

Yes, but it is fairly unlikely. PacifiCorp might be motivated to sell a resource if <u>all</u> of the following actions occur:

1. One of the following occurs:
   a. The Commission waives the current requirement that PacifiCorp provide a cost-of-service rate to all classes of consumers; or
   b. A large amount of PacifiCorp's Oregon load chooses the direct access option on a permanent basis. (An option currently under discussion in Oregon).

2. Based on the reduced amount of load that PacifiCorp is obligated to serve because of one of the above, the Commission and PacifiCorp agree on a resource plan that excludes, for purposes of ratemaking, some of PacifiCorp's resources.

3. The Commission undertakes an administrative valuation process to place a one-time value on all of PacifiCorp resources.

4. PacifiCorp does not agree to the Commission-determined valuation regarding resources to be removed from its revenue requirements.

5. PacifiCorp requests third-party arbitration to determine the value of the resource(s) and does not agree with the arbitrator's decision. Rather than accepting the arbitrator's determination regarding the value(s), PacifiCorp exercises its option to auction the resource(s).

Does Oregon's restructuring law require Oregon to include a "fixed slice" of PacifiCorp's resources in PacifiCorp's revenue requirement?

No, nothing in Oregon law requires the Commission to include in PacifiCorp's rates a "fixed slice" of its resources. The on-going valuation method of calculating transition credits and charges is perfectly compatible with modifying the allocation of generation costs among PacifiCorp's state jurisdictions. However, a slice valuation might be used in calculating a one-time valuation of resources.

What is the ongoing valuation method of calculating transition charges and credits?

This method compares the "traditional" revenue requirement of generating resources (test year costs expressed on a cents per kWh basis) to an equivalent amount of generation supply at market prices. Under this approach, transition charges and credits would likely be recalculated on an annual basis. Ongoing valuation method is to be used to calculate transition charges or credits until the one-time valuation is completed.

How did the concept of a" fixed slice" of PacifiCorp generation get started?

Commission administrative rules established to implement SB 1149 directed PacifiCorp to develop a value of its resources, assuming a fixed percentage (slice) of resources allocated to Oregon. Developing a value for a fixed slice of PacifiCorp resources was one approach to calculate a one-time transition charge or credit. A fixed slice is consistent with the policy that no new resources would be included in rates, at cost, by the Oregon Commission.

When does the one-time administrative valuation occur?

Once PacifiCorp and the Commission agree on a resource plan identifying the resources that should be retained in revenue requirement to meet the loads of consumers eligible for a cost of service rate.

Is there a requirement that PacifiCorp and the Commission agrees on a resource plan?

No. The "rules the Commission adopted to implement SB 1149" (rules) do not explicitly require that the Commission and PacifiCorp agree on the terms of a resource plan. However, the rules create a multi-stage process, in which parties may make counter-offers regarding acceptable plans, that increases the likelihood of agreement on the terms of a resource plan.

When does the ongoing valuation method apply?

The ongoing valuation method is used to calculate transition charges and credits until a utility's resource plan is adopted and a one-time valuation of resources has been completed.

Does the ongoing valuation methodology provide an effective base for permanent implementation of SB 1149?

No, not with respect to promoting a competitive market, which is a key foundation of SB 1149. This is for two reasons. First, a transition charge or credit that changes each year, which is a feature of ongoing valuation, discourages consumers from making longer-term resource commitments. This is because instead of facing a fixed transition charge or credit, the customer faces an unknown stream of future annual charges or credits, thereby creating uncertainty in the value of the stream of charges or credits. Second, ongoing valuation in effect resets the utility power supply rate to direct-access eligible consumers such that it is fairly equivalent to market prices at the exact time consumers must decide whether to go to market. The combination of these factors discourages development of a competitive market. In addition, ongoing valuation continues to place plant performance risks on all consumers. This conflicts with one objective of consumers choosing direct access which is to end the power supply business relationship with the company, including bearing any risks associated with future company plant performance.

What is the process for the one-time administrative valuation?

Once the company and the Commission agree on a resource plan, the company will file with the Commission what it believes to be the market values of each if its resources. The market value of the plant will be calculated by estimating the price of the plant assuming it was sold to a third party. The value of a plant, for purposes of the resource plan, will be the difference between the market value of the output of the plant and the costs of operating the plant. Once PacifiCorp has filed what it believes to be the market values for the resources, other major parties will have the opportunity to hire appraisers to estimate values for each of the plants. The Commission will ultimately issue an order determining the value of the plants, after a contested case hearing. If the Commission's determination is challenged by any party, the value will be "reviewed" through what is essentially third-party arbitration. If the Commission first, and PacifiCorp second, both reject the value of the plant after the arbitration review process is complete, then the company has the option to sell the plant.

What is the purpose of the transition charges and credits?

The purpose of transition credits and charges is two fold. First, from the company perspective, the credits and charges are intended to ensure that the utility has the same opportunity to recover its costs under direct access as it does under standard regulation. That is why the one-time transition charge or credit, when added to market, equals book. (Or the ongoing transition charge or credit, when added to a market price of such power over a year, equals that year's revenue requirements expressed on a per kWh basis.) As a general matter, PacifiCorp's revenue requirements associated with generation are spread among all the consumers. Accordingly, if Oregon law did not provide for transition charges and credits, PacifiCorp would not be assured of recovering its generation costs if a customer chooses direct access. More specifically, if a customer chooses direct access, PacifiCorp no longer needs the power previously used to supply the customer. While PacifiCorp may sell that freed-up power to the market, market prices may not be sufficient, or may be too high, to match PacifiCorp's costs for the power incorporated into its revenue requirements. A transition credit or charge will allow PacifiCorp to match revenue obtained from the market sale to generation costs in its revenue requirements.

From the customer perspective, the transition charges and credits are intended to retain for the customer the benefits or drawbacks of the utility resources, whether or not the customer chooses direct access. This is based on the proposition that if direct access consumers are required to pay stranded costs, they should be entitled to any stranded benefits. For example, assume that the market price of electricity is 3.5 cents per kWh, and from a revenue requirement perspective, that the average cost of electricity supply for the utility is two cents per kWh. Without the 1.5 cents per kWh transition credit, the customer would face the prospect of remaining with the company and buying electricity at two cents per kWh, or choosing direct access and purchasing from a market supplier at 3.5 cents per kWh. The transition credit allows the customer to retain the 1.5 cents per kWh benefit of the utility resources and purchase market power. In this latter case, the consumer buys market power for 3.5 cents per kWh, and with the addition of the 1.5 cents per kWh credit; pays a net two cents per kWh. Without this treatment, there would be no prospect of developing a competitive market for electricity supply to retail consumers.

Customer perspective	Market Price	Company Price	Transition Credit	Net Price
Stay with Company		2 ¢ per kWh	0 ¢ per kWh	2 ¢ per kWh
Buy from competitor without transition charges or credits	3.5 ¢ per kWh		0 ¢ per kWh	3.5 ¢ per kWh
Buy from competitor with transition charges and credits	3.5 ¢ per kWh		1.5 ¢ per kWh	2¢ per kWh

Note that the transition charge or credit is based on a comparison of PacifiCorp's fully allocated average costs (revenue requirements) to shorter-term wholesale market prices.

The objective of the transition charges and credits is to:

- not harm or benefit the company
- not harm or benefit the remaining cost of service consumers
- not advantage or disadvantage competitive power suppliers
- allow direct access consumers access to the market on an equitable basis

Are the parties in Oregon discussing sidestepping the transition charge and credit calculations to "jump start" direct access?

Yes. Parties are discussing the possibility of allowing large consumers the opportunity to choose direct access, and at the same time waive any right to return to cost of service rates. For such consumers, there would be no transition charge or credit. In effect, the one-time market value of the utility's resources is deemed to equal the cost of the resources. It is unclear whether the Commission has statutory authority to accept a customer's waiver of the cost-of-service requirement prior to July 2003. Parties are pursuing this option to: 1) avoid the one-time valuation process; 2) allow some consumers to choose direct access; and 3) because the current market price strips appear to be close to the long-term costs of utility resources. Parties also believe that in the short-term, if consumers choose direct access, the remaining consumers may not face significant rate increases or decreases, as these remaining consumers receive the costs and benefits of the plants.

Is there a potential conflict between current inter-jurisdictional allocations and Oregon's implementation of direct access?

Yes. As noted previously, when a customer chooses direct access, absent the jump-start concept, the customer faces a transition charge or credit. This credit or charge reflects the difference between market value of the power consumed by the customer and PacifiCorp's revenue requirements associated with supplying the power. One can think of the transition charge or credit as PacifiCorp selling the power on the market, taking that money, subtracting from it the revenue requirement cost of that power, and giving the net difference to the customer. In essence, this is a wholesale sale where 100% of the defined proceeds are credited to Oregon. This approach is inconsistent with inter-jurisdictional allocations in that the latter allocates revenues from wholesale sales across the states, based on allocation factors. Under this method of allocation, Oregon would possibly get 33% of the net short-term margins from the sale. For example, if market prices were 3.5 cents per kWh and revenue requirements is two cents per kWh, the net difference is 1.5 cents per kWh that gets credited in full to the direct access customer. PacifiCorp pays the customer 1.5 cents per kWh.

In the world of inter-jurisdictional allocations, PacifiCorp's sales for resale have increased, with its variable costs equaling one cent per kWh and market prices equaling 3.5 cents per kWh. The difference between PacifiCorp's costs and market prices results in margins of 2.5 cents. (In this variant, market is not compared to revenue requirements but rather to PacifiCorp's short-term operating costs.) PacifiCorp's margins from the sale are allocated across the jurisdictions. Assuming the combined states other than Oregon represent two-thirds of total allocations, PacifiCorp could credit those states with two-thirds of 2.5 cents per kWh or, 1.67 cents of sales for resale margin per kWh. However, in Oregon, PacifiCorp is also crediting the customer 1.5 cents per kWh for the transition credit. In all, PacifiCorp credits its states with 1.5 + 1.67 cents per kWh for a total of 3.17 cents per kWh for the increased wholesale activity associated with an Oregon customer choosing direct access. Wholesale margins were only 2.5 cents per kWh in reality; so, PacifiCorp has the potential to be harmed by 0.67 cents per kWh for the entire Oregon direct access load. It is an open question whether this harm is a result of inconsistent commitments that PacifiCorp made when it obtained approval of the Pacific Power and Light merger with Utah Power and Light.

Company Perspective	Oregon Transition Credit Paid	Other states wholesale revenue credit	Actual Revenue Available	Net Result on Company Profits
Customer stays with Company	0 ¢ per kWh	0 ¢ per kWh	0 ¢ per kWh	0 ¢ per kWh
Customer chooses direct access	1.5 ¢ per kWh	1.67 ¢ per kWh	2.5 ¢ per kWh	-0.67¢ per kWh

Note that the interjurisdictional wholesale revenue credit is based on comparing wholesale market prices to PacifiCorp short-term operating costs.

Have the customer groups in Oregon agreed to hold PacifiCorp harmless?

Yes, in the near term. Customer groups agreed to administrative rules requiring direct access consumers to hold PacifiCorp harmless through December 31, 2002. This result would be achieved by adjusting the transition charge or credits, as needed, when other states include the sales for resale revenues associated with Oregon direct access activity in PacifiCorp's rates for that state. It has not been necessary to invoke this provision.

What is PacifiCorp's current position on this hold harmless provision?

When market prices skyrocketed, the risk to PacifiCorp, post 2002, increased significantly as well. Therefore, PacifiCorp wants the opportunity to extend the hold harmless provision, based on these perceived risks. Customer groups oppose extension of this provision. PUC Staff is supportive of this concept, given the significant change in market prices from when the original hold harmless provision was negotiated.

Has the Oregon Commission adopted a rule requiring that new resources be placed in rates at market rates rather than costs?

Yes. In a PGE docket several years ago, staff proposed, and the Commission adopted, the policy that new generating resources no longer be recognized in rates. Accordingly, all new resources would be included in revenue requirement at market prices, not at cost. Later, after passage of SB 1149, parties supported, and the Commission adopted, a rule specifying that all new resources would be included in rates at market, not at cost. There is currently a dispute among the parties whether this rule should be changed. PacifiCorp supports revising the rule so that new resources may be placed in rates at cost until a resource plan is adopted. OPUC staff also supports revisiting the rule.

Even if the Oregon Commission continued to not recognize new resources in rates, does that mean new PacifiCorp generation would no longer be allocated to Oregon?

No. New generation could continue to be allocated to Oregon. The Oregon Commission could decide to include the new generation in rates based on market prices instead of costs.

KEY PROVISIONS OF SB 1149
(as amended by HB 3633 passed by 2001 legislature)

- By March 1, 2002, Portland General Electric Company (PGE) and PacifiCorp were required to provide their consumers the following options:
  - Direct access for nonresidential consumers;
  - A portfolio of options (such as market-based and green rates) for residential consumers. The PUC decided to offer the small nonresidential consumers portfolio options as well;
  - A standard offer option for nonresidential consumers;
  - A cost-of-service rate option for all consumers (the PUC may waive this requirement for large nonresidential consumers after July 1, 2003, if it makes certain findings about market performance); and
  - Default service for nonresidential consumers.

- On March 1, 2002, PGE and PacifiCorp began collecting a three percent charge assessed to all customer classes to fund various public purposes.

- PGE and PacifiCorp also were required to collect $5 million on an annual basis for low-income bill payment assistance beginning January 1, 2000, which increased to $10 million annually on October 1, 2001.

- The PUC was directed to:
  - Ensure that direct access does not cause unwarranted cost shifting among various customer classes;
  - Determine transition charges or credits;
  - Develop policies to eliminate barriers to the development of a competitive retail market;
  - Certify electricity service suppliers and establish other consumer protections;
  - Adopt various rules necessary to implement the Act; and
  - Revise rates to unbundle the main business functions such as distribution, generation and transmission.

- A consumer-owned utility (a municipal utility, cooperative, or PUD) can decide whether and under what terms and conditions it will offer its consumers direct access or portfolio options. Once a consumer-owned utility offers direct access, it shall collect from eligible consumers a public purposes charge.

- Cities can collect privilege taxes from distribution utilities providing direct access through volumetric charges equivalent to the existing franchise fee based on gross revenues.

The electric restructuring law established a general framework, but it left much of the implementation up to the Oregon Public Utility Commission through its rulemaking and rate setting processes. The following is an outline of basic elements of SB 1149 (as amended by HB 3633).

- The utility isn't required to sell any assets which generate electricity;
- Utilities can continue to negotiate long term wholesale contracts to protect the consumer from the volatile spot market;
- No consumer is forced into the energy market;
- All consumers have the choice of receiving a regulated cost-of-service rate from the utility at least until July 2003;
- All nonresidential consumers will have the ability to purchase electricity either from an ESS or their existing utility;
- Both large and small nonresidential consumers who buy power from an ESS have the opportunity to return to a cost-of-service rate in the near term;
- Each utility provides default emergency rates in case an ESS halts service to a nonresidential customer;
- Bills were redesigned to reflect the various costs that factor into a total bill; and
- All consumers receive information so that they may compare the fuel mix and emissions of the electricity supply options that are offered to them.

Residential and small nonresidential consumers receive a portfolio of energy options. Small nonresidential is defined as those who use less than 30 kW monthly. The portfolio includes:

- a traditional basic rate
- a Time-of-Day Supply Service
- a Fixed Renewable Service that includes new renewable resources
- a "Renewable Usage" Service
- a "Habitat Restoration" Service
- Seasonal Flux (PacifiCorp only)

Small business consumers can also opt for Direct Access.

A 12-member portfolio advisory committee crafted the options and recommended them to the Commission for approval. The committee included utility representatives, local governments, residential consumer and small non-residential groups, public/regional interest groups, and staff of the Oregon Public Utility Commission and Oregon Office of Energy.

PUBLIC PURPOSE FEE AND LOW INCOME BILL ASSISTANCE

The law establishes an annual expenditure by the utilities of 3% of their revenues to fund "Public Purposes," including energy efficiency, development of new renewable energy, and low-income weatherization. On March 1, 2002, rates increased for PacifiCorp and PGE consumers by 3% to fund these activities. The public purpose fee will appear as a separate item on consumers' bills.

The first 10% of the Public Purposes Fund goes to Education Service Districts for energy audits and subsequent energy efficiency measures.

The remaining money in the fund goes into four public purpose accounts:

- 56.7%- Conservation
- 17.1%-Renewable energy
- 11.7% Low-income weatherization
- 04.5%-Low-income housing

The conservation and renewable energy funds are administered through a new nonprofit entity, the Oregon Energy Trust.

The law also established a $10 million a year low-income bill assistance fund to be spent in the territory of the utility that collects it. The current amount is 35 cents a month for residential consumers and .035 cents/kWh for nonresidential consumers capped at $500 per month, per site. The Oregon Housing and Community Services Agency distributes the money through community action agencies.

MORE DETAILED DISCUSSION

Senate Bill 1149 was passed in the 70th Oregon Legislative Assembly and signed by Governor Kitzhaber on July 23, 1999. The main thrust of SB 1149 is to provide new power supply options for consumers of certain electric utilities in the state. These new options include direct access for business consumers (enabling them to buy power from a supplier other than the local utility) and a portfolio of renewable resource and other options for residential consumers. The legislation was codified primarily in ORS 757.600 to 757.691.

This section of the report discusses the treatment of major issues in the administrative rules and other PUC decisions. The issues addressed are: customer service options, transition costs and benefits, consumer protection, safety and reliability, public purposes, low income bill payment assistance, code of conduct, issues related to the Bonneville Power Administration, and privilege taxes.

A. Service Options

Direct Access - Direct access is the ability of a consumer to purchase electricity and related services in the competitive market. By March 1, 2002, Portland General Electric (PGE) and PacifiCorp were required to allow nonresidential consumers to choose direct access. After March 1, 2002, PacifiCorp and PGE may enter into special contracts only for distribution service. Line extension charges must be independent of a consumer's supply option. PacifiCorp and PGE must standardize their tariffs to conform to industry standards and ensure its tariffs work in conjunction with their tariffs approved by the Federal Energy Regulatory Commission. The Commission was required to eliminate barriers to the development of a competitive retail market structure.

Portfolio Options - The statutes and rules specify that by March 1, 2002, PGE and PacifiCorp will offer a portfolio of options to residential consumers. At a minimum, one option must reflect renewable energy resources and another must be a market-based option. There can be more than one option for each of the above, however; at least one renewable energy resource product must contain significant new resources.

Pursuant to the rules, an advisory committee was assembled to deal with many of the issues involved in offering the portfolio options to consumers. The Advisory Committee consists of members from the following entities: Office of Energy, PUC, local governments, PGE, PacifiCorp, residential consumers, public/regional interest groups, and small nonresidential consumers. On March 20, 2001, the PUC adopted the advisory committee's recommendations for a time-of-use rate, a blended and a block renewable resource rate, and an environmental mitigation option for the portfolio. Enrollment will occur on an ongoing basis and portfolio options will be offered to small nonresidential consumers.

Cost of Service Rates - All classes of consumers will continue to be offered a cost of service rate until at least July 1, 2003. A cost of service rate is based on the traditional methods of determining and allocating the PGE and PacifiCorp's costs. Unless a new consumer elects otherwise, the consumer will be served under the cost of service option. After July 1, 2003, the Commission may waive the requirement of PGE and PacifiCorp to provide a cost of service rate to non residential consumers if the Commission finds, through a public process and hearings, that a market exists in which retail electricity consumers subject to the waiver are able to:

- Purchase supplies of electricity adequate to meet the needs of the retail electricity consumers;
- Obtain multiple offers for electricity supplies within a reasonable period of time;
- Obtain reliable supplies of electricity; and
- Purchase electricity at prices that are not unduly volatile and that are just and reasonable.

Nonresidential Standard Offer - Small and large nonresidential consumers will be eligible to purchase a standard offer option. The standard offer rates will be based on supply purchases made on a competitive basis from the wholesale market. The rates are expected to be comparable to options available in the direct access market. With the transition charge or credit, the standard offer should be comparable to a traditional cost-of-service rate. For PacifiCorp, the cost of service rate is the Standard Offer. For PGE, the Standard Offer is the cost of service rate.

Default Supply - Nonresidential consumers will be allowed to purchase emergency or nonemergency default service. The default supply options are provided by the PGE and PacifiCorp and ensure that consumers in the direct access market, even in the event of failure of the consumer's electricity service supplier (ESS), will have an option. Emergency default service commences if PGE or PacifiCorp, respectively, receives less than five days notice. Standard offer service is provided as the nonemergency default service.

B. Transition Costs and Benefits

Resource Plan - There was broad consensus among interested parties to have PGE and PacifiCorp each develop, through a public process, a Resource Plan. The purpose of the Resource Plan is to identify which resources should continue to be dedicated to serve all consumers eligible for a cost of service rate. A Resource Plan is not final until there is agreement by PGE or PacifiCorp and the PUC. Parties also agreed that the Resource Plan could be modified, as new information becomes available. Because it is not clear, in the long term, which classes will not be eligible for a cost of service rate, the dockets to review Resource Plans have been placed on hold.

Multi-State Regulatory Treatment Issues - PacifiCorp was concerned about the potential economic harm that may be caused by adverse regulatory treatment by other states in which PacifiCorp provides electric service. Other states might claim the benefits of resources "freed-up" when Oregon consumers select direct access. This issue was initially resolved by parties agreeing to hold PacifiCorp harmless through December 31, 2002, for adverse regulatory treatment by other states directly related to implementing direct access in Oregon. PacifiCorp agreed to bear adverse regulatory treatment by other states beginning January 1, 2003. However, when market prices increased dramatically, the risk associated with this issue increased as well. PacifiCorp no longer supports the hold harmless agreement. This issue is currently unresolved.

Valuation Process - SB 1149 requires that the PUC develop market valuation methodologies that provide transition charges or credits that reasonably balance the interests of PGE and PacifiCorp and their consumers. For example, one aspect of the SB 1149 is that consumers can shop for alternative generation suppliers (called direct access) without risking their rights to the benefits of or avoiding their obligations to utility-owned generation. That is, whether a consumer chooses to continue buying power from the regulated utility or buy power from an independent power marketer, the consumer will continue receiving the benefits or pay the costs of the utility generation. The benefit or obligation is delivered to a consumer in the form of a rate credit or charge.

Determination of Rate Credit - Until a One-time valuation is completed, the Commission will establish the rate credit through an investigation using an approach called, "Ongoing Valuation". Ongoing Valuation compares what it would cost to supply the utility's electric loads for one year using only market purchases to what it would cost recognizing the energy available from the utility's generation plants and contract purchase commitments. The difference in these costs is then transformed into a rate credit that is available to consumers should they choose either direct access or remain with the company.

Until the PUC completes the process of assigning values to PGE and PacifiCorp's power supply assets, transition credits will be determined through ongoing valuation. The resulting credit will be updated periodically to reflect changing costs and market conditions.

C. Consumer Protection

Certification - An Electricity Service Supplier must be certified annually by the PUC. An ESS must provide certain information: name, address, telephone numbers, a regulatory contact, financial and credit information, identification of services to be provided, targeted consumers, geographical service area, work experience of key personnel, and technical competence documentation. In addition, an ESS must attest that it will provide a toll-free number to assist consumers in resolving complaints and billing disputes, comply with the law, and maintain financial assurance in case of loss by a creditor or customer.

The PUC may, upon written complaint or on its own motion, revoke the license of an ESS. There are specific reasons for revocation listed in the rules, but revocation is not limited to the reasons listed.

Aggregation - The PUC is requiring potential aggregators to register with the PUC for purposes of protecting consumers. The PUC does not have the authority to revoke the registration of the aggregator. The rules specifically state the electric companies must allow the aggregation of electricity loads.

Billing - The rules state that PGE and PacifiCorp must both provide a consolidated bill unless the customer chooses either separate bills from an ESS and PGE or PacifiCorp, or a consolidated bill from the ESS. An ESS and PGE, or PacifiCorp, must cooperate and ensure the timely exchange of information necessary for billing purposes. The PUC may be consulted to resolve billing disputes.

Metering - PUC rules require that the PGE and PacifiCorp must own or lease, maintain, install, test, read, and remove as needed, a meter for each metered consumer. This meter will be used for billing purposes. To address the ESS's concern about the ability to use more technologically advanced meters, PGE and PacifiCorp must both also offer optional (for fee) meters to provide additional functions at the request of the ESS or the consumer. If that request is denied, the ESS or consumer may appeal to the PUC for further review.

Supplier Changes - A great deal of coordination is involved between PGE and PacifiCorp and an ESS if a consumer changes suppliers. An ESS may not provide service to a consumer unless it has written or electronic authorization and a Direct Access Service Request (DASR). A DASR is an electronic notice that contains information required PGE and PacifiCorp to effect the switch. The DASR must conform to industry protocols. There are specific timelines in the rules with which both an ESS and PGE and PacifiCorp must comply in order for the switch to occur.

Labeling - SB 1149 required specific labeling for nonresidential consumers. The rules adopted also contain labeling requirements for residential and small nonresidential consumers. Price, power source, and environmental impact are reported to nonresidential consumers on or with each bill from an ESS or PGE, or PacifiCorp. The same information is reported at least quarterly to residential consumers.

PGE and PacifiCorp must report power source and environmental impact based on its own generating resources. PGE's and PacifiCorp's net market purchases, the net system power mix may be used. An ESS is allowed to use the net system power mix.

D. Safety and Reliability

An ESS applicant is required to attest that it will comply with applicable laws, rules, PUC orders, and PGE and PacifiCorp tariffs. In addition, if an ESS owns, operates or controls electrical supply lines and facilities, then it must have maintenance programs similar to those required for all other electric system operators in Oregon. The rules require written plans and records that are available to the PUC upon request and the reporting of certain incidents. System reliability is emphasized in the scheduling requirements for an ESS.

In response to Section 15a of SB 1149, the PUC has adopted a revised PUC Meter Policy for electric companies. This policy better reflects the actual scope of metering work done by distribution utilities and reinforces practices that enhance safety and reliability, protect against revenue loss and assure correct customer billing.

The PUC has also revised and enhanced the Service Quality Measures that provide strong regulatory incentives for maintaining levels of safety, reliability and customer service for both PacifiCorp and PGE. Section 18 of SB 1149 provides that key provisions of the bill cannot go into effect unless the PUC certifies that PGE's and PacifiCorp's ability to maintain safety and reliability will not be impaired by implementation of the Act. This determination was made in PGE and PacifiCorp restructuring filings (UE 115 and UE 116), final orders have been issued in those dockets.

E. Public Purposes

Section 3 of SB 1149 requires electric companies and ESSs to collect a public purpose charge from their consumers for a period of 10 years, beginning on the date direct access is offered. The public purpose charge is 3 percent (1 percent for certain aluminum plants) of the amount collected for electricity services, distribution, ancillary services, metering and billing, transition charges, and other types of costs included in electric rates when the legislation was passed. The collections will be used to fund local conservation, market transformation conservation, renewable resources, low-income weatherization, and low-income housing.

The PUC adopted a rule in AR 380 (OAR 860-038-0480) that implements most of the public purpose provisions of Sections 3(1)-(5), 3(9), and 3(a) of SB 1149. The PUC adopted additional public purpose requirements in its AR 390 rulemaking. The Office of Energy is in the process of adopting rules that implement Sections 3(5), 3(6), and 27(9) of the law.

Issues were raised about the PUC's rule on public purposes focused primarily on interpretations of SB 1149 provisions that allow large consumers to "self-direct" the conservation and renewables portions of their public purpose charges. The language in Section 3(5)(a) of SB 1149 required interpretation as to whether self-directing consumers will be subject to different allocations of funds to the public purposes identified in the law than the allocations that apply to all other consumers. After receiving legal interpretation on the issues from the Department of Justice, the PUC decided that the same allocation factors would apply to self-directing consumers. Another issue was raised about whether the public purpose charge should be used to pay for historical utility expenditures on conservation investments as well as the "new" conservation specified in the law. The PUC decided in AR 380 that public purpose collections for conservation should be used to fund new conservation only. Historical conservation investment balances remaining on the utilities' books on the date of direct access will be recovered along with other utility transition costs and benefits.

In addition to the two rulemakings, the PUC decided that a new nonprofit organization should administer the funds collected for conservation and renewables rather than the utilities, in accordance with the authority granted in Section 3(3)(d) of SB 1149. The decision was made in a public meeting based on the recommendations of staff and other parties developed through workshops and meetings with interested parties. The new organization was named the Energy Trust of Oregon, Inc. by the board of directors at its first meeting on March 1, 2001. The board will make decisions on how the conservation and renewables funds collected through public purpose charges should be spent consistent with the requirements of SB 1149 and PUC guidelines.

The Office of Energy is helping the education service districts (ESDs) plan for their 10 percent allocation of the public purpose funds. Office of Energy staff identified 800 schools in 112 school districts in 17 ESDs to help establish both a technical committee to work out program details and a policy committee to review and enact the program. The policy committee will design a plan for administering the program and for writing the program rules.

F. Low-Income Bill Payment Assistance

Section 3(8) of SB 1149 directs PGE and PacifiCorp to collect a low-income electric bill payment assistance charge from their retail consumers. The charge was designed to collect a statewide total of $5 million a year for the period from January 1, 2000, to the date direct access began, at which time the total collection increased to $10 million under Section 3(7)[3]. No customer shall be required to pay more than $500 per month per site for this low-income assistance.

After a workshop with interested parties and discussions with PUC staff, PGE and PacifiCorp filed tariffs to begin collecting the low-income assistance charge on January 19, 2000. (The companies did not propose to have the tariffs go into effect on January 1, 2000 in order to avoid Y2K complications.) The PUC approved the proposed tariffs at its January 18, 2000 public meeting. The tariffs are designed so that 1) a PGE customer pays the same amount as a similar PacifiCorp customer, and 2) the charges should collect about $5.2 million a year between the two electric companies. The current charges are 18 cents a month for residential consumers and .018 cents per kWh for all other consumers. The electric companies will adjust the charges as needed so that $5 million a year is collected and paid to Housing and Community Services (HCS) for the period from January 1, 2000 to the date direct access is offered. At the end of each month, the two electric companies forward to HCS an amount equal to billings of these charges to consumers whose billing cycles ended in the previous month (less a standard allowance for uncollectibles). HCS, in consultation with its Advisory Committee on Energy, has allocated funds to its service delivery network monthly as it receives payments from the electric companies. The average funding level for the 29 counties affected has been $442,233 per month ($275,781 from PGE and $166,452 from PacifiCorp).

G. Code of Conduct

The PUC is mandated by SB 1149 to adopt a code of conduct for electric companies and their affiliates as a protection against market abuses and anticompetitive practices. Further, the PUC

[3] Section 3(7) states that the total to be collected after direct access is offered is "$10 million. SB 843 amends this provision to read "$10 million per year."

is required to adopt policies to eliminate barriers to competitive retail market structure, including policies that alleviate market power and prohibit preferential treatment regarding generation or market affiliates.

The rules adopted accomplish this by addressing various conditioned and prohibited actions involving PGE or PacifiCorp and its competitive operations or affiliates. For example, the rule includes: a) restricted use of PGE's and PacifiCorp's and logo, b) prohibition of preferential access to confidential consumer information, c) prohibition of cross-subsidization, d) prohibition of joint marketing and exclusive referral arrangements, and e) requirements for electric companies to make compliance filings and to fairly treat all competitors.

The parties held three workshops to present their respective points of view, provide clarifications, and discuss solutions to their differences. Also, the parties filed initial and final written comments prior to and subsequent to the final workshop regarding the proposed rules. The PUC adopted the final AR 390 administrative rules on January 3, 2001 in Order No. 01-073, except with respect to transmission and distribution (T & D) access that required additional time for participants and PUC Staff to develop a mutually acceptable rule. The PUC adopted a final T & D access rule on March 13, 2001 in Order No. 01-233.

H. Issues Related to the Bonneville Power Administration

The PUC has two key objectives regarding access to BPA low-cost power. First, the benefits must be protected and preserved for the benefit of PGE and PacifiCorp consumers who qualify for such benefits under the Northwest Power Act. Second, the benefits must be shared equitably among all qualifying PGE and PacifiCorp consumers.

The PUC achieves these two objectives through ESS certification rules. First, as a condition of certification, an ESS must agree to assign back to electric companies any federal system benefits made available to the ESS on behalf of the PGE or PacifiCorp distribution consumers for whom the ESS provides power. Second, an ESS must agree not to enter into a "residential exchange" contractual arrangement with BPA for service to PGE and PacifiCorp distribution consumers. (The residential exchange refers to Section 5(c) of the Northwest Power Act.) These protections are needed not only for the residential class of consumers but also consumers on other rate schedules eligible for direct access. This result occurs because federal system benefits are available to farm loads, up to 400 horsepower irrigation loads, and these farms are served by different schedules depending on their size.

Section 18(1) of SB 1149 states that key provision of the bill cannot be implemented until the PUC concludes that direct access under Section 2 and market structure requirements in Section 6 will not jeopardize the ability of the electric companies to access cost-based power from BPA on behalf of residential and small farm consumers. A PUC Staff finding that no such harm will occur was considered by the PUC at a Public Meeting on April 3, 2001, and adopted by the PUC in Order No. 01-321.

I. Privilege Taxes

SB 1149 allows cities to impose volumetric-based privilege taxes on electric utilities and requires the PUC to determine the manner in which the privilege tax is to be collected for regulated utilities.

The PUC has a longstanding policy of allowing a certain level of franchise fees and privilege taxes (up to 3.5 percent of an electric utility's gross revenues) as an operating expense to be charged to all the utility's consumers; amounts above that level must be itemized and billed separately to the consumers of the city. The rule adopted in AR 380 maintains the policy of allowing a certain level of revenue-based franchise fees and privilege taxes to be included as operating expense and extends the policy to volumetric-based fees. For those cities imposing a volumetric-based privilege tax, the utilities must calculate a base volumetric rate for each customer class equivalent to the revenue-based limit. That rate will be used to calculate the amount that the utility may include as an operating expense. The PUC must ensure that the tax is allocated across customer classes in the same proportional amounts as levied by the cities against the utility.

The PUC found no requirement in SB 1149 that it reconsider the maximum level allowable as operating expenses. Some parties argued that Section 14(4)(b) of SB 1149 requires all franchise fees and privilege taxes to be itemized on customer bills. The PUC disagreed, based on the interpretation that franchise fees and privilege taxes are imposed on the utility rather than on consumers. Under OAR 860-022-0040(7), any party may request that the PUC consider establishing a different level for the percentage of these taxes that may be included in a utility's operating expense.

<end>

Problem Statement

Divergent policy goals among the states, particularly the potential for direct access allowing retail customers to choose alternative energy suppliers and accommodation of future growth, combined with a general breakdown of the inter-jurisdictional cost allocation process, seem to have compromised PacifiCorp's ability to effectively and coherently plan for an optimally-configured future. Consumers may be harmed as a result of less reliable energy supply. Further, the disparate cost allocation methods used by its state jurisdictions do not provide PacifiCorp an opportunity to recover its prudently incurred costs, financially harming the Company.

Discussion

PacifiCorp is a vertically integrated utility providing service to retail customers in the states of California, Idaho, Oregon, Utah, Washington and Wyoming. PacifiCorp uses its generating resources and transmission system, along with wholesale market opportunities, to supply the electric needs of its retail jurisdictions. These activities necessarily entail incurring costs. Following the merger of Pacific Power & Light and Utah Power & Light, regulators in each of PacifiCorp's jurisdictions developed methods for allocating generation and transmission related costs among the states. While those methods worked reasonably well in the past, they do not now.

The major issues facing PacifiCorp are summarized below:

Breakdown of the Interjurisdictional Cost Allocation Process

Divergence over interjurisdictional cost allocations results in the Company continuing to suffer a material earnings shortfall, and creates perverse incentives and disincentives.

Direct access initiatives in Oregon or Elsewhere

Current interjurisdictional allocation methods are not sufficiently flexible to allow each state to pursue (or not pursue) direct access without adverse impact to other states. Historically, when PacifiCorp sold its service territory in Montana, PacifiCorp's other states assumed the responsibility for PacifiCorp's fixed costs in the territory (e.g., corporate and generation.) PacifiCorp has anticipated its remaining jurisdictions will do the same if it is successful in selling its territory in California. This method of reassignment is not satisfactory for purposes of implementing direct access or sale of service territory.

Divergent Policy Goals of State Commissions Regulating PacifiCorp

In testimony drafted in December 2000, PacifiCorp expressed its concern that the different states do not share similar views regarding load growth and resource acquisition. These disparate policies appear to adversely impact PacifiCorp's decisions regarding the construction or acquisition of new regulated generation.

Detailed Discussion

PacifiCorp believes that it will be called upon to invest several billion dollars in new generation resources, transmission expansion, re-licensing of hydroelectric facilities and clean air requirements for thermal facilities in the next five to ten years. Although the bulk of the outlays may be some years off, the commitment to invest is, in some cases, immediate. For example, the Company is currently involved in collaborative processes related to re-licensing of its major hydroelectric facilities. Decisions related to clean air requirements are also on the near horizon.

As noted above, PacifiCorp's jurisdictions have different perspectives and policies regarding the issues described above. Relying on information provided by the Company, these policies and perspectives are as follows:

Utah has currently adopted a "rolled-in" allocation method for existing and new resources. However, Utah is experiencing rapid load growth and increasing summer peak demands. It is concerned about the Company not adding generation resources because of uncertainty regarding the three general issues of: direct access, divergent state policy goals and inter-jurisdictional allocation shortfalls. Utah is generally of the view that new rate base additions based upon the results of traditional least-cost planning are appropriate. PacifiCorp has stated that Utah industrial customers are interested in direct access and are concerned about having long-term responsibility for new generating plants. There are several special contracts in Utah. Utah is concerned about how to accommodate Oregon's restructuring initiative within the current allocation framework.

Oregon is committed to the implementation of direct access under SB 1149. It appears that Oregon may not support long-term rate base additions for certain classes of customers in the event the Company will not be obligated to provide a cost-of-service rate to those customers in the future. Oregon is concerned about inappropriately subsidizing load growth in Utah and other jurisdictions' special contracts. Due to increases in DSM investment, per the Energy Trust, Oregon is also concerned about the manner in which Demand Side Management (DSM) costs and benefits are allocated. Oregon wants to retain the benefit (and costs) of northwest hydro resources, which is in direct conflict with a fully rolled-in allocation method. Oregon is not currently authorizing any new special contracts for industrial customers.

Wyoming also appears concerned about the Company not investing in generation and transmission infrastructure. However, as a relatively slow growing state, it could be benefited if costs of new generation are not allocated on a rolled-in basis. The Wyoming industrial customers appear interested in retaining a direct access option.

Washington is concerned that it will be adversely impacted by direct access initiatives in Oregon. Washington appears to favor evaluating resource-planning decisions on the basis of their impact on Washington customers, as opposed to their system-wide impact. Washington is interested in pursuing DSM opportunities. Washington wants to retain the benefits of northwest hydro resources. Washington also wants PacifiCorp to develop a resource plan that is "least cost" to Washington, which would likely not result in the same resource additions as a plan that is "least cost" to the entire PacifiCorp system.

Idaho is very interested in issues related to special contracts because of the relative magnitude of the Monsanto load. Also, as a relatively slow growing service territory, Idaho could benefit from a departure from rolled-in allocation methods for new resources. Idaho appears to have little interest in implementing direct access.

Given these different perspectives it is likely the states would arrive at disparate outcomes if the various issues confronting the Company were addressed in separate state proceedings. These inconsistent outcomes would increase the risk that the Company will make decisions that are not in the best interests of its customers.

Scenarios under the worst of circumstances include:

- Double Counting of Stranded Benefits – other states absorb Oregon direct access resources while Company is required to pay stranded benefits. Impact: lack of approval for sale or allocation of resources to fund payment; value could be in excess of $500 million NPV for 1000 MW.
- States Disagree on Relicensing or Clean Air Requirements – certain states may support plant retirement, others support further investment. Impact: stalemate on recovery of billions of dollars of investment; potential plant closure with regional supply issues.
- Under-Recovery of Investment in resources to meet summer peak needs – Utah allows 38%; other states do not allow anything. Impact: $50 million on an $80 million investment (for 120 MW).
- Investment community concerns about PacifiCorp's inability to recover all of its prudently incurred costs. Impact: Downgrading of securities and higher financing costs.
- Counter party concerns regarding downgrading of securities. Impact: additional capital would need to be held for credit support.

While PacifiCorp does not expect that all of these scenarios will come to pass, the compounded investment risk to PacifiCorp is serious. This, combined with the existing inter-jurisdictional shortfall creates a need for collaboration on PacifiCorp's multi-state issues.

Research, including a DPU report, indicates that PacifiCorp is in an uncommon circumstance with respect to its inter-jurisdictional allocation complexities. Yet, PacifiCorp's return on equity is often set against a group of comparables that do not face such risks. As PacifiCorp's real cost of capital steadily exceeds its allowed cost of capital, its financial integrity is at risk. Less dramatic risks of failure include: a continued inability to effectively respond to the individual needs of its states and customers, a least common denominator approach to resource decisions, "risk averse" decisions by the Company that do not maximize efficiency, a potential for stalemate if all states fail to agree or for perverse incentives if states act independently, and a gradual weakening of the financial integrity of the Company.

ISSUES

The three problems identified at the beginning of this paper are headings for subsets of multiple issues identified by MSP participants.[1] These subsets of issues, in part, provide the framework for the Oregon Coalition's consideration of the problems. More specifically, the Oregon Coalition's goal is to predicate an equitable solution to the problems identified above on consistent treatment of the many sub-issues identified by MSP participants. Those sub-issues include, but are not necessarily limited to, the following:

Pre- and Post-Merger Generation

Fixed Costs

- Should existing generation be allocated on a rolled-in basis?
- Should the allocation method continue to differentiate between pre- and post-merger resources?
- Should existing generation be allocated on a rolled-in basis, with a carve out for Hydro Endowment?
- Should the fixed cost allocation factor reflect cost causality? (e.g., have the fixed cost allocation factor vary depending on the type of resource to better match the appropriate weighting of capacity and energy)
- How should environmental costs associated with thermal generation be allocated?
- How should costs associated with retirement of existing generation be allocated?
- How should costs associated with repowering existing generation be allocated?

Variable Costs

- Should variable costs be directly assigned to cost causers?
- At what point is directly assigning variable costs non-economic?
- Should variable costs be directly assigned when doing so is non-economic?
- Should variable costs be allocated using traditional monthly power cost modeling, PacifiCorp's new hourly power cost modeling capability, or some other method?

[1] The three problems identified by the Utah DPU could be considered headings for the problems identified by the Oregon Coalition.

New Resources

- Should costs for new resources be directly assigned when necessitated by load growth in one or more jurisdictions?
- Should the allocation method change with the type of new generation?
- What happens when jurisdictions do not agree that PacifiCorp's investment in a new resource is prudent or that it is consistent with the PacifiCorp's integrated resource plan?
- How should costs be allocated when a type of generation, (e.g., wind), is dictated by a particular jurisdiction but costs more than market?
- Should there be rate base additions for new major generating facilities?
- Should costs of new generation be allocated by subscription?
- If subscription, what occurs when the resource is over- or under-subscribed?
- How can the MSP participants balance PacifiCorp's need for certainty in order to plan for new resources with each jurisdiction's right to evaluate resource acquisition to determine whether acquisition satisfies jurisdictional requirements?

Special Contracts

- How should special contracts be defined?
- How should costs/benefits of special contracts be allocated?
- How should system-wide benefits associated with special contracts be valued?
- Who should develop the estimate of value of the system-wide benefits?
- How should economic benefits of a special contract that should be borne by jurisdiction (e.g. economic development/retention), as opposed to the system, be valued?
- Should components of special contract that provide system-wide benefits be incorporated into a separate contract?

Demand-Side Management

- What programs are properly classified as DSM for purposes of interjurisdictional allocations?
- How should demand-side management (DSM) system-wide benefits be valued?
- Who should be responsible for verifying DSM savings?
- How should costs/benefits of DSM be allocated?
- Is the differential between average and marginal costs such that it is not economical to specifically allocate costs/benefits of DSM?
- Does whether the system is in a surplus, as opposed to a deficit, impact the equitability of allocations related to DSM?

Hydro Endowment

- How should the jurisdictions calculate the value of the Hydro Endowment?
- If the former Pacific Division jurisdictions retain the Hydro Endowment, should these jurisdictions assume full responsibility for the following costs?
    - environmental
    - federal relicensing
    - dam removal
    - replacement power cost for reduction in generation output
- If one or more of the former Pacific Division jurisdictions does not wish to retain the Hydro Endowment, how should this respective portion(s) of the Hydro Endowment be allocated?

Direct Access Load

- How should costs/benefits of generation freed up by direct access be allocated?
- How can jurisdictions that have implemented direct access provide PacifiCorp certainty with respect to forecasting for future generation needs?

Sale or Purchase of Service Territory

- How should costs/benefits associated with sale of service territory be allocated?

Transmission

- How should PacifiCorp re-classify assets so that distribution costs are equitably allocated in each of its jurisdictions?
- What occurs if PacifiCorp's assets are classified differently for purposes of state and federal regulation?
- Should network rights be reassigned in connection with a jurisdiction's implementation of direct access?
- How should network rights be assigned in connection with PacifiCorp's sale of territory?

UM 1050/PacifiCorp MSP Divisional Separation Model

Issue	9/9/02 Accounting "Ownership" Model*	Oregon Proposed Modifications
Pre-Merger Generation Facilities	**Step 1:** Use 1996 12-CP to assign fixed slices of facilities (including post-merger investment) to jurisdictions.	**Step 1:** Use a 1996 allocation factor based on 75% 12-CP and 25% annual energy (SG factor) to assign fixed slices of the pre-merger generation plants (including post-merger investments), purchase power contracts and wholesale sales contracts to the jurisdictions within the Division in which they originated.
Pre-Merger Purchase Power Contracts	**Step 3:** Allocate contracts on a capacity or MW basis according to remaining need, as determined by 2003 projected peak load exceeding assignment of capacity of pre-and post-merger generation plants.	**Step 1:** (See above)
Pre-Merger LT Wholesale Sales Contracts	(Ignore both costs and revenues for jurisdictional revenue requirement purposes.)	**Step 1:** (See above)
Existing Post-Merger Generation Facilities	**Step 2:** Assign capacity from each plant to each jurisdiction in proportion to the degree to which its 2003 peak load exceeds its entitlement share of capacity in "owned" pre-merger generation facilities.	**Step 2: option 1-** Utilize the PacifiCorp drafted designation of post merger generation and contracts. Oregon Coalition would support one change that would designate Cholla assigned to Pacific division. (Reflects perceived comments of Utah parties); or **option 2-** applying the "3-bucket" allocation methodology used in MSP study 31.
Existing Post-Merger Purchase Power Contracts	**Step 3:** Same as pre-merger contracts, above.	**Step 2:** (See above)
Existing Post-Merger Long Term Wholesale Sales Contracts	(Ignore both costs and revenues for jurisdictional revenue requirement purposes.)	**Step 2:** (See above)
Variable Costs (generation plants and purchase contracts)	Costs, and revenues from sales to the market, follow plant and contract assignment; interjurisdictional interchange at market prices; hourly, jurisdiction level, calculation.	

* This column represents Oregon Coalition's understanding of the proposal prepared by George Compton of the Utah Division of Public Utilities.

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UM 1050/PacifiCorp MSP Divisional Separation Model

Future Generation Plants, Long Term Purchase and Sales Contracts	Subscription by each jurisdiction prior to acquisition.	**Option 1:** IRP like **Option 2:** allocate using "3-bucket" as applied in MSP study #31.
Generation Capacity Transfers and Load Losses Due to Direct Access, etc.	Costs of resources continue to be assigned to jurisdiction. Surplus capacity could be sold to other jurisdictions or outside party, with rate base modified by premium or discount.	Add the option of a power sale to other jurisdictions or outside party.
Special Contracts	Firm portion plus interruptible portion compatible with jurisdiction's reserve requirement assigned situs. Remaining system portion offered to other jurisdictions and subsidiaries; amount not picked up assigned situs.	Situs assignment of total "special contract" customer loads and revenues; ancillary service benefits separated, independently valued, and assignment system wide as ancillary service costs.
Reserves	Each jurisdiction responsible in proportion to its share of system coincident peak. Use of other states' reserves at market-based compensation.	Each jurisdiction responsible for contingency reserves required by assigned resources and regulating reserves allocated based on jurisdictional load; use of other states' reserves compensated at market prices; hourly calculation.
DSM	Situs. (Ownership model should be on a jurisdiction rather than divisional basis.)	
Transmission/Distribution Reclassification	No change…likely determined by FERC and regional RTO.	Costs for Class B assets allocated on basis of function, rather than federal classification. Function determined by application of FERC seven-factor test. Using the seven-factor test, PacifiCorp should request and advocate reclassification of these assets, where warranted.
Sale or Purchase of Service Territory	Sale: generation resources retained and transferred at book value to needy jurisdictions. Purchase: PacifiCorp responsible for providing resources, except to extent existing jurisdictions willing to share capacity surplus.	Sale: reallocation of system to surviving jurisdictions. Purchase: Any purchase of an investor-owned utility providing service in a state PacifiCorp also provides retail service would trigger a revisit of issues by MSP participants.

* This column represents Oregon Coalition's understanding of the proposal prepared by George Compton of the Utah Division of Public Utilities.

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UM 1050/PacifiCorp MSP Divisional Separation Model

Extreme Events		For catastrophic failure of a power plant and other extreme events, such as very poor hydroelectric availability, beyond the control of the Company affecting power production or delivery of power, replacement power costs will be allocated system-wide rather than situs.

* This column represents Oregon Coalition's understanding of the proposal prepared by George Compton of the Utah Division of Public Utilities.

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Introduction

The following are potential resolutions to some of the issues identified by MSP participants at the May 2002 MSP meeting. This document reflects further refinement of the proposal drafted by the Oregon Coalition prior to the July Las Vegas MSP meeting.

The Oregon Coalition is cognizant that any proposal to modify interjurisdictional allocations for PacifiCorp will likely result in some cost shifting among PacifiCorp's jurisdictions. This is true of the following proposals. Since any final solution will have to satisfy the statutory standards for each state, we will need to develop other features, apart from the resolution of these particular MSP issues, such as timing of implementation or outboard monetary credits, in order to balance the interests of all the states as well as PacifiCorp.

These proposals are strictly what is contemplated by Robert Hanfling and the other MSP participants at this stage in the MSP process – completely non-binding and subject to modification or rescission.

Existing Pre- and Post-Merger Generation Fixed Costs

Background: The Oregon Coalition proposes to allocate the benefits and costs of all pre- and post-merger generation, with the exception of pre-merger hydro facilities and Mid-C Contracts, on a rolled in basis. A discussion of why the Oregon Coalition proposes to exempt the Hydro Endowment from rolled-in treatment is set forth in the Oregon Coalition's discussion of the Hydro Endowment.

Proposal: All existing generation, with the exception of pre-merger hydro facilities and the Mid-C Contracts, should be treated as system resources and allocated accordingly. (Treatment of pre-merger hydro facilities, including the Mid-C Contracts, is discussed in the Hydro Endowment section.) Environmental costs associated with existing generation should also be allocated system-wide, again, with the exception of environmental costs associated with the Hydro Endowment. Fixed generation costs should be allocated using "buckets" as described below. (We could support treating the costs and benefits of new generation on a rolled-in basis if the jurisdictions agree to allocate variable energy costs on an hourly basis and using "buckets" as described below. Allocation on a rolled-in basis provides an alternative to subscription, as described later in this document.)

One significant consequence of this proposal would be to reduce the level of benefits the former Pacific Power & Light division currently receives for pre-merger assets. This is because this proposal rolls-in pre-merger, low-cost thermal generation located in the former Pacific Division. These resources are not currently allocated on a rolled-in basis

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under Modified Accord. Rough estimates of the impact of rolling in low-cost thermal, as well as all other pre-merger plant, compared to Modified Accord, is over $11 million per year in higher costs assigned to Oregon.

A critical component of this proposal is a revision to the classification of fixed generation costs between capacity and energy. To obtain a classification that reflects standard economic principles, the classification of fixed generation costs is predicated on the expected use of the generation resources. This is because it is not appropriate to allocate fixed costs for baseload and peaking facilities using the same percentage split of capacity and energy.

Specifically, baseload plants typically have low operating costs and high fixed costs. Baseload plants are added to systems primarily to provide energy and therefore should have a greater proportion of fixed generation costs assigned to energy than to capacity. Peaker facilities are built to provide capacity. These plants typically have lower fixed costs and higher operating costs, compared to baseload plants, and accordingly, most of the fixed generation costs should be assigned to capacity.

These varying ratios of energy and capacity are currently reflected in PacifiCorp's avoided cost studies, which recognize this feature by assigning the portion of fixed costs of the proxy plant in the avoided cost study to capacity that equals the capacity costs of a simple cycle combustion turbine.

For purposes of allocations using "buckets", fixed generation costs are classified into one of the following three buckets, "baseload", "peaking' and "mid-range". The table below illustrates this categorization.

Buckets	Resources, Purchase Power, and Wholesale Sales	Allocation of Costs to Hours or Months	Allocation of Costs and Revenues to State Jurisdictions (described below table)
Base-load	Annual capacity factor above 80%	Divide annual costs by 8760 and multiply the hours in each month	25% monthly coincidental peak factor + 75% monthly energy factor (more emphasis on energy)
Mid-range	Annual capacity factor less than 80% and above 30%	Spread annual fixed costs to the hours of operation of each unit (use GRID run results, disallowing system balancing sales)	50% monthly coincidental peak factor + 50% monthly energy factor
Peaking	Annual capacity factor less than 30%	Same as Mid-range	75% monthly coincidental peak factor + 25% monthly energy factor (more emphasis on capacity)

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In modeling the "buckets" concept, PacifiCorp placed hydro resources in the Mid-range bucket under a uniform shape (assigning equally across all hours for each month). PacifiCorp categorized the thermal plants as Base-load, with the exception of the Gadsby plant, its portion of the Hermiston plant, and the Hermiston purchase contract, which PacifiCorp categorized as Mid-range. PacifiCorp largely categorized purchased power and wholesale sales contracts as Mid-range.

PacifiCorp also set the monthly coincidental peak factor for each state equal to the ratio (for each month) of state hourly coincident peak to the highest total system hourly load for the month. The monthly and hourly energy factor for each state was the ratio of state load to total system load.

PacifiCorp provided the table on the following page in response to OPUC Staff Data Request No. 39 b. This table provides a breakdown between demand (capacity) and energy, by state, of the generation costs assigned within the state for rate spread purposes. Several of the states use the interjurisdictional allocations as the basis for rate spread. Accordingly, if the buckets concept is implemented by the states, states may wish to reconsider whether rate spread should be based on interjurisdictional allocation agreements.

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	Demand	Energy	Total Generation Related Costs (Fixed plus variable)	Demand	Energy	Total
OR	$ 150,568,000	$ 284,613,644	$ 435,181,644	34.6%	65.4%	100.0%
CA	$ 9,976,000	$ 29,338,571	$ 39,314,571	25.4%	74.6%	100.0%
UT	$ 290,414,994	$ 268,235,069	$ 558,650,063	52.0%	48.0%	100.0%
WY_ Combined	$ 99,889,044	$ 98,415,151	$ 198,304,195	50.4%	49.6%	100.0%
ID	$ 46,356,193	$ 44,012,965	$ 90,369,158	51.3%	48.7%	100.0%
WA	$ 50,312,034	$ 41,055,245	$ 91,367,279	55.1%	44.9%	100.0%

	Test Periods	Reference
OR	12 months ending Dec. 31 2001	PacifiCorp Marginal Cost Study, Table 4
CA	June 2003	PacifiCorp Marginal Cost Study, Table 4
UT	12 months ending Sept. 30, 2000	PacifiCorp Embedded Cost of Service Study, Unit Cost @ Target Return
WY Combined	12 months ending Sept. 2001	PacifiCorp Embedded Cost of Service Study, Unit Cost @ Target Return
ID	12 months ending March 2001	PacifiCorp Embedded Cost of Service Study, Unit Cost @ Target Return
WA	12 months ending Dec. 31, 1998	PacifiCorp Embedded Cost of Service Study, Unit Cost @ Normalized Return

Existing Pre- and Post-Merger Generation Variable Costs

Background: MSP participants appear to agree that as a general principle, costs should be borne by the cost causers to the extent possible, or at least as practicable. With hourly power cost modeling capability now being available, the traditional method of allocating variable power costs, which is on an annual basis, can be improved.

For purposes of jurisdictional allocations, direct access loads would be treated the same as standard retail loads, except that a credit would accrue to the states with direct access equal to the wholesale market value of power in the aMW amount and shape of the direct access load. This would provide direct access loads equivalent treatment on a jurisdictional allocations basis as it is treated in Oregon for retail ratemaking purposes. In Oregon the approach is called "ongoing valuation."[1]

[1] See May 10, 2002, "Deregulation/Open Access by Marc Hellman of the Public Utility Commission of Oregon.

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Proposal: Net variable power costs should be allocated to states on an hourly basis, based on retail jurisdictional loads in each hour. (Retail jurisdictional loads include all loads for which PacifiCorp provides retail distribution services.)

The states with direct access would also be assigned power cost credits equaling the market value of a wholesale sale of load, typically with a term of one year, equal to the aMW size and shape of the direct access load.

New Generation

Background: As noted above, the Oregon Coalition has two alternate proposals for allocating the costs and benefits of new generation. The first proposal is subscription, which has been discussed at prior MSP meetings. The second proposal is to allocate the costs using the buckets approach described above.

Currently, Oregon's subscription proposal most closely mirrors the "generic subscription" process described in the memorandum provided to MSP participants by PacifiCorp at the September MSP meeting. This process would be an extension of the Company's IRP and include the following steps:

1) PacifiCorp makes a formal filing in each jurisdiction regarding the development of a resource called for in the IRP. The filing requests findings on the jurisdiction's perceived need for the resource and whether it anticipated wanting an allocation from the resource that differs from its standard allocation.
2) Each jurisdiction has a notice and comment process. Interested parties are allowed discovery.
3) Each Commission issues findings on the need for the resource and on whether it anticipates the jurisdiction would want an allocated share of the resource that differs from the usual allocation, and describes that difference.

The findings of each Commission *would not* have preclusive effect on any subsequent ratemaking treatment for the resource.

However, as discussed at the September MSP meeting, Oregon has enacted legislation that permits the Oregon Commission to make substantive decisions regarding the ratemaking treatment for a new resource prior to the time the resource is built. Under ORS 757.212, the Commission may issue, as an alternate form of regulation, an order approving a utility's proposal to build a new generating plant or to enter into a long-term wholesale contract or sales agreement. In such an order the Commission must address to what extent the public utility will use power from the new resource to serve the utility's retail load. Oregon's legislation could be a blueprint for a subscription process that allows each jurisdiction to address, in a more substantive manner than the generic

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subscription process described above, whether it will subscribe to a share of a proposed new generation resource. The steps for such a process would be as follows:

1) PacifiCorp makes a tariff filing in each jurisdiction describing a plan to construct a generating plant or enter into a long-term wholesale power purchase or sales agreement.
2) Each jurisdiction reviews the tariff filing.
3) In any order approving the tariff, and thus the plan to acquire the new generation, each commission would address the extent to which PacifiCorp will use the new generation resource to serve the jurisdiction's customers.

If each jurisdiction followed these steps prior to the construction of a new resource, it would be clear to all the jurisdictions and PacifiCorp whether the resource is wanted by each jurisdiction and to what extent. As noted above, Oregon may only undertake this process under the authority granted in ORS 757.212. The Coalition recognizes that other commissions may currently be without such authority to undertake such a process.

Proposal 1: a) Generic Subscription. Prior to construction or acquisition of new resource, PacifiCorp makes a formal filing in each jurisdiction requesting findings on need for resource and on any anticipated departure from the jurisdiction's usual allocation (Again, dynamic rolled in is an option if there is agreement to assign variable costs on an hourly basis and to use "buckets".)

b) Alternative Form of Regulation pursuant to ORS 757.212. Prior to the construction or acquisition of a new resource, PacifiCorp files a tariff in each jurisdiction proposing the acquisition. Each jurisdiction reviews the tariff filing, determining to what extent PacifiCorp will use power from the resource to serve the jurisdiction's customers, and how the costs and revenues of the new resource will be reflected in PacifiCorp's rates.

Proposal 2: Assuming jurisdictions agree to allocate variable energy costs on an hourly basis and "buckets", or some variant that similarly reflects cost causation and economic principles, the costs of new generation resources could be allocated on a rolled-in basis. However, allow allocation by subscription for specified resources to allow states to pursue their energy policies or goals. For example, allocate by subscription when a state makes a request/recommendation to PacifiCorp to purchase resources that have costs greater than the least cost alternative.

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Hydro Endowment

Background: Both the Oregon Governor and the Public Utility Commission of Oregon (OPUC) have established the public policy of retaining for Oregon residents the benefits the region's low cost resources. In 1996, Oregon Governor John Kitzhaber issued a Statement of Principles for Restructuring the Electric Utility Industry. That Statement contains the following Overriding Objectives:

Overriding Objectives

> *1. Achieve efficiencies in producing, delivering and using electricity to yield reductions in costs.*
>
> *2. Ensure the benefits of competition are shared by all electricity consumers.*
>
> *3. Protect Oregon's environmental quality.*
>
> *4. Maintain the reliability, safety and quality of electric service.*
>
> *5. Preserve the benefits of our low-cost resources for Oregon customers.*

Subsequently, in December of 1998, Portland General Electric (PGE) requested that the OPUC approve its proposal to restructure its business operation. PGE proposed to sell all of its generation resources as part of the restructuring proposal.[2] The OPUC denied PGE's request to sell its hydroelectric generation resources, noting that the proposed sale would not fully comply with the Governor's objective to preserve for Oregon customers the benefits of Oregon's low-cost resources. The Commission further noted,

> We also conclude that retention of [PGE's hydroelectric facilities] will preserve the benefits of low-cost resources, our goal and one of the goals set out in the Governor's Principles. Their sale would take them out of our reach and create uncertainty. Retention will also eliminate any suggestion of intergenerational inequity between those who take service now and those who take service after the conclusion of the amortization period for transition costs.[3]

Consistent with the state's public policy announced by the governor and OPUC, the Oregon Coalition proposes that the Northwest region retain the benefit of its low-cost resources. Importantly, the Coalition recognizes that it is only equitable to assume the

[2] OPUC Order No. 99-033.
[3] *Id.*, at 21.

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costs of the low-cost resources in connection with its receipt of the benefits, and proposes to do so. Finally, the Oregon Coalition believes that the Mid-C hydroelectric contracts are also low-cost resources subject to public policy adopted by both the OPUC and Oregon Governor. For this reason, the Oregon Coalition proposes the same treatment for these contracts as for PacifiCorp's hydroelectric facilities.

Proposal: Pre-merger hydroelectric facilities and long-term hydroelectric contracts (Mid-C Contracts), including their current and future direct costs, and available output, should be assigned to their respective pre-merger divisions. Direct costs assigned should include federal re-licensing and environmental costs. Environmental costs would include costs to breach a dam, if required by federal law. However, environmental costs would not include costs for replacement generation for breached dams or for generation lost in relicensing. Replacement generation costs would be treated in the same manner as costs associated with new generation to meet demand associated with load growth in other states.

Oregon Coalition proposes that the costs and benefits of the pre-merger hydroelectric-based resources should be directly assigned to the respective divisions. For purposes of cost allocations, the relevant loads used for allocation should be decremented equal to the expected output of the hydro endowment. For example, if the hydro endowment equals 500 aMW, then the pre-merger Pacific Power jurisdictions would have its loads decremented by 500 aMW for purposes of allocating costs such as the remaining generation fixed costs.

Treatment of Direct Access Load

Background: One key objective of the Oregon Coalition is to allow states to implement their energy policies without harming or benefiting other states. We have crafted a proposal that achieves that objective. The jurisdictional loads of each state, for allocation of fixed generation and variable costs purposes, would be based on retail distribution loads and hence include a state's direct access load. In addition, a credit would be directed to a state with direct access load equal to the wholesale market value of power of the same aMW and shape as the state's direct access load. The direct assignment of such revenues is intended to reflect the opportunities by the Company to sell power on the wholesale market that otherwise would have been provided to the end-use customer had that customer not chosen direct access.

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Proposal: For allocations of generation fixed and variable costs, include all loads for customers served by PacifiCorp retail distribution. States having direct access loads would be assigned a credit equal to the wholesale sales market value of power of the same aMW size and shape of the direct access load.

Special Contracts

Background: At the May 2002 MSP meeting, participants identified several issues associated with retail Special Contracts allocations. (For purposes of this proposal, a "Special Contract" refers to any delivery of power under contract terms different from those for standard firm tariff service.) The issues center primarily on how to define, distinguish and value the non-standard components of a Special Contract (e.g., interruptibility.) To resolve these issues, the Oregon Coalition proposes that non-standard firm tariff features of a special contract (e.g., ancillary services) be captured through separate contracts between the Company and the customer for the sale of services from the customer to the Company. (The services could also be sold to a third power.) Alternatively, states could choose to retain bundled tariffs; however the services sold back to the Company would still need valuation. Loads, whether they be standard tariff sales, special contracts, or direct access customers, would continue to be treated the same as standard tariff sales for purposes of interjurisdictional allocations.

Proposal: For purposes of allocation, special contract load should be treated as if it had been purchased at standard tariff rates and as such, the power costs incurred to serve the load allocated on a situs basis. Notwithstanding each jurisdiction's choice regarding integrated or separate contracts, a specific value should be assigned to the interruptibility and other ancillary services (Ancillary Services) that benefit the system. The PacifiCorp purchase and use of Ancillary Services, if any, should be treated as a system-wide cost. The purchase price should reflect the market value of these services. (If the Ancillary Services were sold to a third party, then the revenue from the sale would be credited to the special contract customer.) To ensure an appropriate market value is assigned to these Ancillary Services, the terms and conditions of any special contract must be made available to interested parties of other states, while appropriately protecting commercial business interests.

To the extent any special contract load becomes lost load due to economic shut down or relocation, the load would no longer be included in interjurisdictional allocations. In other words, load lost with the termination of operations by a special-contract customer would be treated as any other lost retail load.

The Oregon Coalition proposes two alternatives for valuing the interruptibility and other ancillary service components of a special contract. The first alternative is to require that

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an independent third party determine the market value of these components. The Oregon Coalition does not have a firm opinion at this time regarding the timing of the valuation. On one hand, the valuation could be used to assist the negotiations between the Company and the customer. On the other hand, the valuation could be used solely for the purpose of jurisdictional allocations and costs.

A second alternative is to allow PacifiCorp to determine the value of these components for purposes of interjurisdictional allocations. However, PacifiCorp's determination will be guided by criteria agreed to by the MSP participants. It is the Oregon Coalition's understanding that PacifiCorp is currently developing criteria such as this.

Whether a third party or PacifiCorp values Ancillary Services provided by the customer through a special contract, the costs of the valuation should be assigned system-wide. Further, notwithstanding how the system-wide benefits of a Special Contract are valued, each jurisdiction retains its authority to review the costs associated with the benefits to determine whether they were prudently incurred.

Additional Option: For any state for which a special contract load, as of January 1, 2002, comprises more than 25% of the state's total load (e.g., Monsanto), the following treatment shall apply. Should all of the special contract load choose to be served through direct access, and waive any rights to return to retail service and agree not to return to retail service even if offered, then the special contract load will be treated the same as economic load loss. (The load would not be recognized for purposes of fixed generation costs allocations.) In addition, any stranded costs or benefits would be allocated system wide.

Demand-Side Management (DSM) Costs

Background: As the Oregon Coalition has emphasized during the MSP process, allocating the costs and benefits of DSM in an equitable manner is important to Oregon. Under Oregon statute, PacifiCorp, and Portland General Electric are required to assess their retail customers a Public Purpose Charge equaling 3% of the annual revenues received from the customers. A significant portion of these charges will fund energy efficiency and low-income weatherization programs. As a consequence of this Oregon requirement, PacifiCorp customers will invest more than $200 million in DSM programs over then next ten years.

Further, from 1992 through 2001, PacifiCorp spent a total of $163 million to acquire (presumably) cost-effective DSM, of which Oregon spent nearly $100 million. These costs were assigned situs, the benefits were not.

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Directly assigning the costs of DSM programs is consistent with what appears to be a generally accepted principle agreed to by the MSP participants, that costs should be directly assigned when possible, or at least when practicable. If DSM costs being assigned on a situs basis, the issue then centers on how the "benefits" of DSM should be allocated.

Originally, the Coalition proposed that the benefits of DSM be similarly assigned on a situs basis and reflect, in part, the market value of the power conserved. Such an approach, while theoretically correct is administratively cumbersome. Treatment of DSM could be simplified if the reduction in PacifiCorp costs assigned to a state, attributable to acquiring DSM, is comparable to the market value of the power conserved through DSM. In this regard, the Oregon Coalition made several information requests of PacifiCorp. In reviewing Company analysis on the issue, it appears that the reduction in loads associated with DSM provides cost allocation savings no less than the cost of market supplies of power for a similar amount of power. Accordingly, the Oregon Coalition has modified its proposal regarding the allocation of DSM benefits.

Proposal: The costs related to a state's DSM programs should be assigned on a situs basis. The reductions in system allocation costs associated with decreased loads attributable to DSM are sufficient consideration to the respective states reflecting the "benefits" of the DSM acquisition. No specific allocation of DSM benefits is necessary.

Transmission/distribution functionalization

Background: Currently, transmission and distribution assets are not classified in a consistent manner between what were formerly the Pacific and Utah Divisions. Failing to take action in the MSP process to make classification of these assets comparable in all PacifiCorp's jurisdictions would thwart one of the primary purposes of this docket: to achieve an equitable allocation among the states.

As the MSP participants have discussed, two pending dockets before the Federal Energy Regulatory Commission (FERC) may affect whether this inequity between the two former divisions can be addressed in this process. However, preliminary orders issued by the FERC reflect that taking steps in MSP to treat transmission assets as distribution assets for allocation purposes, where appropriate, is not inconsistent with the direction of these FERC dockets.

More specifically, in an order recently issued in its Standard Market Design Docket, the FERC addressed how it might determine what transmission facilities would be controlled

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by an Independent Transmission Provider.[4] The FERC proposed the starting point for such a determination would be application of a seven-factor test it designed in its Order No. 888 to identify local retail distribution facilities for purposes of determining whether the facilities were subject to state or federal jurisdiction.[5] In its recent order in the RTO West docket, the FERC instructed the applicant/transmission owners to explain why facilities they proposed to classify as Class B facilities were appropriately controlled by the owners, as opposed to the RTO.[6] In connection with this instruction, the FERC noted that in its July 31, 2002 Order proposing rules for SMD, it had proposed using the seven-factor test enunciated in Order 888 to determine whether facilities would be appropriately operated by an independent transmission provider.[7]

In the proposal circulated for the July MSP meeting, the Oregon coalition proposed that PacifiCorp take action to have FERC reclassify its Class B assets using the FERC's seven-factor test enunciated in its Order No. 888. In light of the recent FERC orders, it may not be necessary for PacifiCorp to initiate a reclassification proceeding before the FERC to obtain the result desired by the Oregon Coalition. PacifiCorp has been instructed to justify to the FERC why it should retain operational control over its Class B assets. The Oregon Coalition believes it is appropriate for PacifiCorp to advocate to the FERC that it (PacifiCorp) should retain control over its Class B assets used to distribute retail service. The Oregon Coalition also believes that for allocation purposes, the state jurisdictions should determine the appropriate allocations for PacifiCorp's Class B assets based on their function, rather than current classification.

To ensure that PacifiCorp's assets are treated consistently by the state jurisdictions and the FERC, PacifiCorp should determine whether its Class B assets are distribution or transmission assets by applying the seven-factor test enunciated by the FERC in its Order No. 888. This determination will help ensure these assets are afforded consistent treatment in this process as well as the pending federal dockets. It would be an extremely odd and unfair result if PacifiCorp demonstrated to the FERC that it should retain operational control over its Class B assets because they are used for local distribution, but costs for these assets were still allocated on the assumption they are "transmission" assets.

Finally, some of the MSP participants have expressed an interest in delaying any action on this issue until after the FERC has issued rulings in one or both of the pending dockets. In light of the recent orders in these dockets, the Coalition does not think this is

[4] Docket No. RM01-12-000 (July 31, 2002 Notice of Proposed Rulemaking).
[5] *Id.*, at ¶¶ 361-69.
[6] Docket No. RT01-35-005 and RT-35-007 (September 18, 2002 Declaratory Order).
[7] *Id.*, at p 25 n 41.

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necessary. The proper classification for PacifiCorp's Class B assets is at issue in both FERC dockets. The FERC has made clear it believes the most appropriate way to resolve this issue is to apply its seven-factor test. There is no reason the MSP participants should not attempt to determine the proper classification of these assets for allocation purposes at the same time, the federal government does so for other purposes.

Proposal: Costs for PacifiCorp's distribution assets should be allocated in an equitable manner system-wide. In other words, costs for distribution assets should be assigned on a situs basis, even if the assets are currently classified by the FERC as "transmission" assets. The determination of whether assets are "distribution" or "transmission" should be made by applying the seven-factor test enunciated by the FERC in its Order No. 888, and not by simply relying on the current classification of the assets at the federal level.

Further, PacifiCorp should advocate to the FERC in all dockets consistently with this proposal. In other words, in the RTO West Docket, PacifiCorp should advocate that its Class B Assets used to distribute retail service to customers are appropriately controlled by PacifiCorp. Using the seven-factor test, PacifiCorp should request and advocate reclassification of these assets, where warranted.

Sale or Purchase of Service Territory

Background: PacifiCorp has undertaken actions in recent years to sell some of its service territories. More specifically, PacifiCorp has sold its Montana territory and proposes to sell its California territory. The Coalition proposes that the MSP participants reach an understanding of how future sales would be treated for allocation purposes. This may reduce PacifiCorp's business risk and allow PacifiCorp to act in a prudent business-like manner. Purchases of service territories should be handled in a manner that protects existing jurisdictions from harm.

Proposal: Sale of service territory -- Any sale of a service territory, or portion thereof, would result in a reallocation of PacifiCorp's system to surviving retail jurisdictions.

Purchase of service territory---The Company should consent to an obligation to demonstrate that the purchase and proposed treatment of new service territory does not harm any of the existing state jurisdictions.

In the event, PacifiCorp purchases another investor-owned utility (e.g., Portland General Electric), for which a majority of that utility's loads are located in a state in which PacifiCorp provides retail service, MSP participants agree that issues resolved in the current process may need to be revisited.

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Oregon Coalition Proposed
Hydro Endowment Methodology

Proposal: Assuming a system dynamic approach to interjurisdictional allocations, assign the costs and output of pre-merger hydroelectric facilities and long-term hydroelectric contracts (Mid-C Contracts) to the respective pre-merger divisions. Direct costs include federal re-licensing and environmental costs. Environmental costs would include costs to breach a dam, if required by federal or state law. However, environmental costs would not include costs for replacement generation for breached dams or for generation lost in relicensing. These replacement generation costs would be treated in the same manner as costs associated with new generation to meet demand associated with load growth in other states.

An "outboard" adjustment would be used for purposes of assigning to each division, and to states within the division, the costs and benefits of the pre-merger hydroelectric-based resources. Two distinct methods would be used to calculate the outboard adjustment to generation related revenue requirements.

Under the control area approach, the hydro endowment calculation is significantly simplified since the costs and benefits of hydro resources and contracts of former Pacific Power & Light division would be assigned to the west control area. The Wyoming loads associated with the former Pacific Power & Light division would need to be treated in an equitable manner given that these loads are designated to be fully in the east control area.

For purposes of cost allocations, the following steps are envisioned:

1. Hydroelectric-related Power Costs
   A. Calculate the "expected energy", by month for pre-merger hydroelectric facilities and long-term hydroelectric contracts (Mid C Contracts). "Expected energy" is the average amount of power over the water year history. (This calculation is not intended to change historic regulatory practice for addressing variability in hydroelectric conditions.)

   B. Dynamically calculate the amount of expected monthly hydroelectric generation allocated on a divisional basis. More specifically, the former Pacific Power & Light division states for which PacifiCorp continues to provide retail service would be allocated the hydroelectric capability from those hydro-based resources and contracts that the division brought to the merger. Likewise for the Utah Power & Light division. Each state would be allocated hydroelectric based power in proportion to annual loads. Allocations would change over time as loads change among the states. The costs of the hydroelectric resources would be assigned to each state consistent with the divisional and proportional load allocation.

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2. Non-Hydroelectric-related Power Costs
   A. Reduce loads for each state, on a monthly basis, consistent with the available hydroelectric-based power calculated in Step #1b. That is, if a state was allocated 40% of hydroelectric-based power, then 40% of expected monthly hydroelectric-based power would be assigned to the state and the state would have a corresponding load reduction.

   B. Assign remaining generation-related power costs such as fixed and variable costs using allocation factors based on the state decremented loads.

3. Derive total power costs by state by summing Step #1b and Step #2b.

4. To construct the "outboard" treatment, first calculate power costs by state assuming the allocation method agreed to by the states and assuming no hydro endowment.

5. Compare the costs in Step #4 to those derived in Step #3 to derive outboard adjustments to Step #4 power costs such that the "outboard adjustment" combined with Step #4 power costs yields Step #3 power cost allocations.

6. Calculate remaining allocation assuming no hydro endowment.

Reserve Adjustment

The Reserve Adjustment is a mechanism that is used to charge or credit states with the reserve services they receive from or provide to the other states. The Reserve Adjustment covers both contingency reserve (spin and non-spin) and regulating reserves (control margin). The Reserve Adjustment may be applied in studies where resources or interruptible contracts are specifically assigned and no other mechanism is in place to recognize the value of reserves the resource brings to the integrated system.

The Reserve Adjustment calculates the difference between each state's hourly reserve requirement and hourly reserves held. This difference, referred to as the state hourly "net reserve position", represents the reserves that each state provides to or receives from other states. Net reserve positions are priced at a shaped version of the OATT tariff to determine the state's incremental hourly expense or revenue credit.

The Reserve Adjustment calculation is based on GRID system dispatch and operating and regulating reserves data. Contingency reserve requirements and contingency reserves held are assigned to the states using the same factors that are used to allocate resource costs.

- In the case of the MSP 3x.3 series of studies, these include the factors used to allocate Base-load, Mid-range and Peaking resources and to allocate company-owned hydro and Mid-C purchase contracts

Process

Step 1: ***Calculate and assign reserve requirements.*** Using hourly dispatch data from GRID, apply 7% to thermal generation and the Hermiston Purchase contract, and 5% to the hydro generation and the Mid-Columbia contracts. The result is the system reserve requirement for contingency reserves.

GRID currently does not report reserve requirements by generating resource, as it does for reserves held. GRID does, however, report spin, non-spin, and regulating margin for the East and West control areas. For the MSP 3x.3 series of studies, contingency reserve requirements are assigned to each state by plant on an hourly basis using:

- The specified combination (weighting) of monthly coincident peak factors and monthly energy load factors for Base-load (25/75%), Mid-range (50/50%), and Peaking (75/25%) plants and
- The monthly Divisional energy factors for company-owned hydro resources and Mid-C purchase contracts (MSP Studies #33 and #35).

The regulating reserves requirement from GRID is allocated to each state pro rata based on hourly loads (as adjusted for the particular study). For each state, the total hourly reserve requirement is determined by adding the contingency reserve requirement and the regulating margin reserve requirement.

Reserve requirements for long-term contracts are reported by GRID on a net basis in the non-spinning reserves requirement. For purposes of computing the total reserve requirement, the non-spin component of the contingency reserve requirement is grossed up for long-term contracts.

Step 2: ***Calculate the total reserves held.*** GRID reports contingency reserves held by resource. Regulating reserves held are embedded in spinning reserves held, and are not reported separately. To segregate regulating reserves held and contingency reserves held, the regulating reserve requirement in Step 1 is deducted from spinning reserves held for each hour. Regulatory reserves held are deemed to be the same as regulation reserve requirements.

Step 3: ***Assign reserves held.*** Contingency reserves held are allocated to each state based on their allocation of plant generation per Table 1 (i.e., weighted coincident peak factors and monthly energy load factors for Base-load, Mid-range, and Peaking plants). These are the same factors used to allocate generation fixed costs and the contingency reserve requirement. Regulating reserves are allocated to each state pro rata based on hourly loads.

Step 4: ***Calculate and price each state's hourly "net reserve position".*** For each hour and each state, the contingency reserves held are subtracted from the contingency reserve requirement. (In this analysis, no such calculation is needed for regulating reserves because regulating reserve requirements and regulating reserves held are the same amount.) Net reserve positions across the jurisdictions sum to zero.

The prevailing OATT tariff is applied to each state's net reserve position.

- In this analysis, the OATT tariff used is $1.19 kw-month; multiplying by 1000 and dividing by the hours in the month converts the charge to a $/MWh rate.
- To shape the OATT tariff, the hourly price forecast for the year was used to derive the hourly shaping curve. First, hourly forecasted prices for DSW, Mid C and COB were capped at $250 and averaged to one hourly market price. Second, an average *annual* price of the combined markets and capped hourly prices was calculated. Third, the percentage of the hourly price to the average annual price was calculated to create an hourly shaping curve. The $/MWh rate was then multiplied by the hourly shaping curve to create an hourly shaped OATT tariff.

Step 5: ***Apply the result to the study's revenue requirements***

Background Information

Reserve Requirements

There are generally two types of reserves: contingency reserves and regulating reserves. PacifiCorp follows the reserve requirements of NWPP Contingency Reserve Sharing Procedure and the WECC's Minimum Operating Reliability Criteria.

Contingency reserves are defined as the amount of reserve that is sufficient to meet the disturbance control standard. Contingency reserve capability must be available within 10 minutes. The contingency reserve is the greater of:

1. The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency (at least half of which must be spinning reserves), or
2. The sum of 5 percent of the load responsibility served by hydro generation and 7 percent of the load responsibility served by thermal generation (at least half of which must be spinning reserves).

Regulating reserves are defined as sufficient capacity that is immediately responsive to automatic generation control and that provides sufficient regulating margin to allow a control area to meet control performance criteria. This reserve can also be defined as the minimum on-line capacity that can be increased or decreased to allow the system to respond to reasonable demand changes in order to be in compliance with the control performance standard in NERC.

The reserve requirements are determined by control area: West and East.

GRID Modeling of Reserves

GRID determines reserve requirements for each hour on each side of the system based on hydro generation and thermal availability. Total hourly hydro generation is determined by the hydro shaping algorithm, and total hourly thermal availability is determined by commitment logic. The reserve requirement calculation also considers non-company-owned generation (e.g. Sunnyside), if that generation requires the Company to hold reserves. GRID adds regulating reserves to spinning reserves.

In GRID, reserve requirements are assigned to resources based on their capabilities. Because most hydro resources are located in the West, the West may hold reserves for the East if transmission is available, because hydro resources are more flexible and can provide reserves without losing generation. Reserves are calculated first for the West in order to determine the remainder of reserves available for transfer to the East. Specifically, the model determines the amount of hourly reserve requirement, both spinning and non-spinning, that is satisfied by hydro resources, defined as the difference between capability and generation level of the hydro resources. Non-company-owned generation that is capable of providing reserves (e.g. Mid-C) is also included in this calculation. If hydro resources cannot satisfy the full reserve requirement, then thermal units with the highest incremental cost in the West hold the remaining reserve requirement for the West.

The maximum amount of reserves that can be transferred from West to East is input into the GRID model based on the dynamic overlay between the two sides.

In the East, the model assigns reserve requirements to resources by first transferring the hydro reserves in the West that are available given transmission constraints. GRID then assigns spinning and non-spinning reserve requirements to thermal units that are capable of holding reserves in descending order of the units' incremental costs. Spinning reserve requirements are allocated to thermal units that are equipped with governor control, and non-spinning reserve requirements are allocated to the rest of the reserve holding thermal units.

The June 2001 SRP filing, based on PDMAC-based modeling, did not include non-spinning reserves and assumed that hydro resources in the West were sufficient to provide all non-spinning reserves and some spinning reserves in the East. In contrast, GRID models both spinning and non-spinning reserves consistent with NERC requirements and takes thermal unit availability and transmission constraints into fuller account. The effect is that a higher portion of reserves is placed on thermal units, thus reducing thermal availability and increasing market purchases (or reducing market sales).

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1050

In the Matter of PACIFICORP Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol.	OREGON COALITION ISSUES PAPER AND ALTERNATE PROPOSALS

DOCKETED

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I. INTRODUCTION

In response to the problems with PacifiCorp's current cost allocation methods, the Industrial Customers of NW Utilities, the Citizens' Utility Board, and the Staff of the Public Utility Commission of Oregon (the Coalition) have been working collaboratively since March of 2002 to find solutions that protect the interests of PacifiCorp's Oregon consumers and are equitable to PacifiCorp and the states in which it operates. In this paper, the Coalition identifies and discusses infirmities in PacifiCorp's proposed "PacifiCorp Inter-jurisdictional Cost Allocation Protocol" ("Protocol") and submits alternate allocation methods that are equitable and protect the interests of PacifiCorp's Oregon consumers.

The Coalition has identified several key principles that any agreement regarding changes in PacifiCorp's inter-jurisdictional cost allocation must address. These principles are as follows:

1. Consumers in one state served by PacifiCorp should not face higher rates due to the Company acquiring energy to meet load growth in another state.
2. Oregon and the Pacific Northwest should retain its historical entitlement to the costs and benefits of the region's low cost hydro resources.
3. Policy decisions and activities by one state should not affect other states either positively or negatively.
4. Any adopted jurisdictional allocation method should be sustainable for all parties and sufficiently flexible so that it may be adapted to address emerging issues.

In addition to these four key principles, the Coalition also adopts the three Commission directives outlined in Order No. 02-193. These three Commission directives are as follows:

1. Determine an allocation methodology that will allow PacifiCorp an opportunity to recover its prudently incurred costs associated with its investment in generation resources;
2. Insure that Oregon's share of PacifiCorp's costs is equitable in relation to other states; and

3. Meet the public interest standard in Oregon.

II. CRITIQUE OF PROTOCOL

The Oregon Coalition does not believe PacifiCorp's current proposal meets any of the Coalition's key principles or that it satisfies the public interest standard in Oregon. Most notably, the Protocol fails to:

1) address risk that Oregon will subsidize Utah load growth;
2) ensure that the Northwest retains its historic entitlement to the region's low-cost hydro resources;
3) allow Oregon to opt out of new resources that it does not need;
4) ensure that new stranded costs will not be incurred for direct access consumers; and
5) allow for independent valuation of special retail sales contracts.

A. Load Growth

The Protocol does not include any tool to protect PacifiCorp's Oregon consumers from cost shifts from Utah to Oregon associated with Utah's load growth. The Company proffers that protection against subsidization of Utah's load growth costs is unnecessary; contending that its analysis demonstrates that meeting Utah's load growth with new resources will not result in any "material" cost shift. The Coalition disagrees with PacifiCorp's assumption that no material cost shifts will result from Utah's load growth.

As discussed below, recent Company studies show that unreasonable cost shifts can occur under the Protocol proposal. Because it is undisputed that Utah is projected to grow at a faster rate than Oregon, the Coalition believes it is imperative to adopt an allocation method that insulates Oregon from the risk of cost shifts from Utah load growth.

Table 1 illustrates the disparate growth rates in MWa's for each of PacifiCorp's states.

Table 1: State Energy Load Forecast in MWa

	WA	OR	CA	WY	ID	UT	TOTAL	Non-UT
2004	517	1,720	107	874	390	2,540	6,148	3,608
2005	524	1,765	109	895	393	2,682	6,369	3,686
2006	531	1,764	109	905	393	2,788	6,491	3,703
2007	538	1,780	110	921	396	2,899	6,645	3,745
2008	547	1,800	112	941	399	3,022	6,822	3,800
2009	555	1,811	113	957	401	3,133	6,971	3,838
2010	564	1,828	114	945	404	3,253	7,109	3,856
2011	575	1,844	116	966	407	3,373	7,281	3,908
2012	588	1,876	118	990	412	3,501	7,484	3,983
2013	597	1,909	119	1,008	415	3,612	7,661	4,049
2014	609	1,948	121	1,031	419	3,733	7,859	4,126
2015	620	1,985	122	1,023	422	3,855	8,029	4,174
2016	634	2,029	124	1,050	427	3,991	8,255	4,264
2017	645	2,062	126	1,072	431	4,112	8,448	4,336
2018	659	2,101	128	1,098	436	4,252	8,674	4,422
	1.75%	1.44%	1.30%	1.65%	0.78%	3.75%	2.49%	1.46%

Utah is forecast to grow considerably faster than Oregon (and the rest of PacifiCorp's service territory) not only on an absolute MWa basis, but as Table 2 illustrates, on a percentage basis as well:

Table 2: Comparison of Projected Energy Load Growth

	2004-2018 Energy Load Forecast			
	Oregon	**Utah**	**WA,CA,ID,WY**	**Total**
Average Annual % Growth	1.4%	3.8%	1.5%	2.5%
MWa Increase	380	1,713	433	2,526
% of MWa Growth	15.1%	67.8%	17.1%	100%
Share of System in 2004	28.0%	41.3%	30.7%	100%
Share of System in 2018	24.2%	49.0%	26.8%	100%

On a relative comparison basis, Utah's peak load is forecast to grow even faster than its energy load – 4.7% per year for peak load versus 3.8% per year for energy load growth. Oregon's forecast growth is 1.4% per year for both energy and peak load. Since

PacifiCorp must plan and acquire resources to serve both energy and peak loads, this additional peak load growth in Utah will require additional power resource and transmission costs. To meet the load growth, PacifiCorp plans to acquire new power resources, including building the Hunter 4 coal plant, several gas-fired combined cycle plants,[1] and other resource options. Table 3 summarizes the planned resource additions currently included in the Company's MSP analysis.

Table 3: Power Resource Additions by Type – 2004-2018

Resource	MW
Thermal Contract	350
Wind	1,420
Coal (Hunter 4)	575
CCCT	1,560
Peaker	200
Reserve Peakers	960
Peaking Contract	100
DSM	236
Total	5,401

Over the last several years it has become apparent that the transmission interconnections between the eastern and western regions of the PacifiCorp system are too limited to ensure a free flow of power across the system. As a result, load growth in the Utah area apparently can be met most economically only by installation of capacity in a nearby Utah location. It is useful to note that the last two major resource additions on the system (the Gadsby and West Valley peakers) were located in Utah, as is the project (Current Creek) that PacifiCorp currently seeks to certify.

These facts suggest that the extra energy available from these resources may not physically be available to serve loads in other areas. Nor will it be available for sale outside the wholesale markets interconnected with the eastern division.

Further, the planning for the system on a forward-looking basis appears to be done on a fragmented, rather than integrated basis. This is evidenced by PacifiCorp's current new power resource acquisition efforts, which consists of four separate Request For

[1] Indeed, the Company is currently in the midst of seeking certification for a combined cycle plant located at its Mona site. The Company justifies the need for this project on the basis of a capacity shortfall of more than 1000 MW in the Utah division.

Proposals (RFP) processes, each of which is specific to either the eastern or western division of the Company's system.

Importantly, the cost of the new generation, which will be rate based, is front-loaded. That is, rate-based plant revenue requirement is typically highest in the early years and declines over the life of the plant. While according to PacifiCorp, these plants are projected to cost less, over the life of the resources, than other resource options such as power purchases, the cost of the plants are typically above market in the near term. With Utah loads growing faster than Oregon, the result under the Protocol is that Oregon is allocated a greater share of the plant costs when the plant costs are the highest; and a smaller proportion of the plant costs when the cost of the plant is lower.

In response to numerous data requests from the Coalition, the Company conducted additional sensitivity analysis that shows Oregon consumers face significant risks of inappropriate cost shifts due to the Company meeting Utah's load growth. The table below summarizes different MSP model run scenarios, identifying assumption changes from the base, and the resulting shift in revenue requirement.

Table 4: Utah Growth Impacts and Effects on Oregon Allocations

	Assumptions		% of Rev Req increase
	Load	Resource Added	to Non-Utah States
(1)	Utah + 200 MW	200 MW CCCT	6% (PC Filing)
(2)	Utah + 1% load	64 MW CCCT	11% (DR 15)
(3)	Utah + 100 MW to Jul & Aug Peak	100 MW CCCT	29% (DR 16)
(4)	Utah + 100 MW to Jul & Aug Peak	100 MW SCCT	24% (DR 16)
(5)	Utah + 500 MW to Jul & Aug Peak	500 MW CCCT	31% (DR 33)
(6)	Utah + 500 MW to Jul & Aug Peak	500 MW SCCT	29% (DR 33)
(7)	Utah + 500 MW to Jul & Aug Peak	500 MW Peak Contract	0% (DR 33)

This table shows that while it appears that the amount of the subsidy varies based on the scenario, a *subsidy is present*, except when market purchases or seasonal contracts are assumed instead of resources being added to rate base.

Additionally, a study initiated by Staff and refined by the Utah Department of Public Utilities shows that Oregon rates are estimated to be nearly $100 million higher

(NPV from 2005-2018) due to Utah loads growing faster than the rest of the system. *See* Appendix B; Estimated Impact on Oregon. This rate impact estimate is very likely on the low side, as PacifiCorp's current RFP process to acquire eastern division resources is not yielding cost effective resource options within the fast growing, transmission constrained service territory. This means that serving the new load will likely cost more than assumed in the MSP studies. Even the information available now, PacifiCorp's data responses and Staff studies, show that the Protocol, under current expectations of each states' load growth, assigns costs to Oregonians that would more appropriately be assigned to Utah.

B. Hydro Endowment

The Coalition believes that the Protocol does not retain the Pacific Northwest's historical entitlement to the costs and benefits of the region's unique low cost hydro resources. While the Protocol has a "hydro endowment" by name, the Protocol hydro endowment simply assigns the costs of the hydro system to the Pacific Northwest, not the benefits. More specifically, the Protocol provides offsetting benefits to Oregon through a "coal endowment", which assigns the costs, but not the benefits, of a coal plant (the Huntington Plant) to the Eastern Division. Because the benefits to Oregon are based on a coal plant, (the assignment to the Eastern Division of some coal plant costs previously assigned to Oregon), the Protocol hydro endowment values the Northwest's Hydro resources at the cost of a coal plant, not the market value of the hydro resources.

Further, while there has been a long history of preserving the benefits of the former Pacific Power & Light hydroelectric resources in inter-jurisdictional allocations, there is no history for providing for a Coal Endowment such as in the Protocol. Although the former Utah Power & Light did have low cost coal power prior to the merger, so did Pacific Power & Light.

Finally, PacifiCorp's proposal gives rise to the potential for gaming with respect to emission controls. For example, if PacifiCorp needs to reduce emissions, the effects on state allocations differ depending on which plants have emission control equipment added. For all these reasons, the proposal for a Coal Endowment is arbitrary and unreasonable.

C. Opt Out

The Protocol provides Oregon with a one-time opt out of the next PacifiCorp coal plant: presumably Hunter 4. If Oregon elects to opt out of the coal plant, then the Protocol increases Oregon's allocation of the most recently constructed natural gas fired generation plant. Correspondingly, the other states then are allocated a larger share of Hunter 4 and a smaller share of the most recent natural gas fired generation plant. The opt out results in the same amount of generation being allocated to Oregon regardless of whether Oregon opts out of Hunter 4.

In short, the opt out substitutes a portion of a coal-fired resource with a natural gas-fired resource. Thus, the Protocol opt out provision really should be called "opt out/opt in". The Company designed this proposal assuming that Oregon's key concern related to environmental issues, specifically increasing carbon dioxide/global warming emissions. While environmental issues may be important, the Coalition's key concern is the prospect of higher rates due to Utah load growth.

For example, significant cost shifts occur if natural gas prices are higher than the Company's base case, which has the price of natural gas at $3.81 per mmBTU. As of January 12, 2004, natural gas prices were quoted above $7 per mmBTU. The company proposal only serves to exacerbate the risk of cost shifts by substituting what might prove to be a low-cost coal resource with a natural gas fired resource.

For these reasons, the Protocol's opt-out provision violates Coalition Principle #3. This is because if Oregon opts out of a resource as allowed in the Protocol, other states allocations would be directly affected.

To improve the concept of an opt-out provision, Oregon should have the opportunity to opt out of any new resource not needed to meet Oregon's additional load. That is, Oregon would recognize new resources in rates to the extent Oregon load grows from current levels. When resources are added to meet Utah load growth, the costs will be allocated system wide using multi-state load data. Therefore, assuming load were to remain at current levels, opting out of a resource would not require an "opt in" to a substitute resource.

Finally, the Protocol does not appear to allow Oregon to "opt in" to Hunter 4 with a delay in its scheduled on-line date. In Oregon's recent review of PacifiCorp's least cost plan, the Commission stated a preference in delaying the online date and revisiting Hunter 4's economics.

D. Direct Access

With respect to direct access and other state policies, the Protocol does not insulate states from actions of another state. For example, under the Protocol, direct access loads are used to allocate costs to Oregonians even if the direct access loads have permanently left the system. The Protocol contemplates that direct access loads will be counted in perpetuity in state jurisdictional allocations.

Under current Oregon policy, direct access consumers pay a transition charge or receive a transition credit. The transition amount is calculated annually under a process known as ongoing valuation. The ongoing valuation methodology may be consistent with the perpetuity feature of the Protocol; however, it is likely that at least some direct access consumers will leave the system permanently pursuant to a one-time valuation of the transition amount. When a consumer chooses to leave the system permanently through direct access, the consumer is responsible for the stranded cost or benefits at the time the consumer leaves the system. That is, the cost of the Company's mix of resources is compared to the projected market price for power and the difference is defined as stranded cost or benefit and the direct access consumer is responsible for this difference.

In the case of stranded costs, charging the departing consumer allows other utility consumers to be held harmless. In the case of stranded benefits, providing the benefit to the consumer removes any barrier to entry of competitive energy service suppliers, without harming remaining consumers. However, a key concept of Direct Access is that the consumer, once having permanently left the system, is no longer responsible for cost recovery of future company actions. The consumer has left the system and the Company is no longer reserving its resources to serve the consumer. Accordingly, no new stranded cost or benefits are attributable to the consumer.

The Protocol, however, continues to allocate to the state generation costs for all resources, both existing and new, without regard to reduction in load due to Direct Access. This violates the no new stranded cost obligations policy. Clearly, the only equitable solution would be to remove the departing loads from the allocation methodology for new resources because the stranded cost/benefit equalization will permanently address any problem resulting from exiting consumers.

It is imperative that the Commission reject PacifiCorp's treatment of Oregon's direct access load. The effect of the Protocol is to allocate new resources to Oregon for direct access loads the Company no longer plans to meet. If this feature of the Protocol were not revised, then non-Oregon states would benefit by having a portion of the new resource available for their use and having only to pay variable cost. This feature of the Protocol, gives a "free-ride" to other states when consumers permanently depart the system for direct access.

The appropriate method for handling direct access loads is as follows:

1. Include in inter-jurisdictional allocations the loads of direct access consumers for those generation resources and contractual obligations, for the life of these resources, that were in place when either the direct access consumer left the system or when the consumer notified the company it no longer wanted the utility to plan to serve its loads; and

2. Exclude direct access loads for purposes of allocating costs of new resource and power purchase commitments made subsequent to the time the direct access consumer permanently left the PacifiCorp generation system or notified the Company to no longer plan to serve the consumer.

E. Special Contracts

Under the protocol there is likely to be conflicts over the value of the ancillary service part of a special contract. The Protocol gives the Commission with jurisdiction over a Special Contract the right to make a determination of the fair market value of the ancillary service part of a special contract. But the fair market value is not a single easily identifiable number. There is likely to be a range of values a Commission could choose as the "fair market value" and the Protocol gives no guidance as to the method to use. Is the fair market value based on the test year used to set rates? Is it different in future test years versus historic test years? Is it based on the time the special contract was signed? If a special contract lasts for ten years, does the host jurisdiction make a finding as to the market value of those ancillary services for ten years? If it finds in four years it has undervalued those services, can it revisit the estimate of fair market value?

A Commission's decision on the terms of a special contract will have a rate impact in its state, which could be significant, and will have a rate impact in other states. A strict reading of the Protocol would suggest other states would be affected because the determination of the value of a special contract's ancillary services is assigned by the host state and other states do not have the right to assign a different value without departing from the terms of the Protocol.

In an answer to a data request, PacifiCorp stated that one state's assignment of a value for the ancillary service part of a special contract that differs from that assigned by the state with jurisdiction would not be considered departing from the terms of the protocol, but instead "represent an issue of interpretation of the Protocol that may be taken before the MSP Standing Committee by PacifiCorp or another party." *See* Appendix C; Response to CUB Data Request No. 3. The Coalition is not comfortable with only the possibility of a favorable result from the MSP Standing Commission as protection from another state's overvaluation of the ancillary service part of a contract.

To ensure Special Contracts are valued comparably and equitably in all PacifiCorp's jurisdiction, the Oregon Coalition has favored an independent determination of the fair market value of ancillary services. In the absence of a process allowing independent valuation, the Coalition believes the Protocol should at least expressly provide that one state's determination of the value of ancillary services is not binding on other states.

III. POSSIBLE SOLUTIONS

A. Hybrid Method

To address the principles and Commission directives outlined earlier, the Coalition offers an alternate proposal for Commission consideration. This proposal is called the Hybrid Method because it allows two control areas to dynamically allocate costs within each control area, but insulates each control area from policy decisions and load growth in the other area. In other words, the proposal is a hybrid of an allocation method that separates PacifiCorp's western control area from its eastern control area. However, within each control area, PacifiCorp's costs would be dynamically allocated across the respective states jurisdictions.

This approach reflects the reality of a limited and strained transmission network underlying the eastern and western divisions of the system already discussed above. Given that planning for system expansion is increasingly based on a divisional, rather than an integrated basis, the Hybrid Method provides a logical and equitable means of distributing the cost of new resources.

The Oregon Coalition supports the Hybrid Method. That method meets our specific goals in that it:

- Dedicates the risks and benefits of the Mid-C contracts and company-owned hydro resources to the Pacific Northwest;
- Insulates the Pacific Northwest from the upward cost pressures resulting from Utah load growth; and
- Allows the Pacific Northwest to independently pursue least cost plans and policies.

1. Description

The Hybrid Method divides the generation system, for regulatory accounting purposes, into two parts-the East and West Regions. It assigns each state's load, each company-owned resource, and nearly all contracts to one of the two regions. Loads in Oregon, Washington and California are assigned to the West Region. Loads in Utah, Wyoming and Idaho are assigned to the East Region. The states in each Region would be set rates to recover the fixed and variable costs of the generating resources assigned to that Region.

This assignment of loads and resources is consistent with the location of loads and resources within the Company's two operational control areas and equitably distributes a significant portion of the Company's production costs. Further, the Hybrid Method includes an interchange methodology that allocates costs and revenues associated with the remaining two elements of production costs - system balancing purchases/sales and interchanges deemed to be made between the two regions. The Hybrid Method also specifies a methodology by which the regions share operational reserves. Within each region, the Hybrid Method allocates costs using a dynamic, rolled-in methodology. Most of the Company's existing hydroelectric resources and the majority of long-term power purchases are assigned to the West Region. Correspondingly, the majority of existing thermal resources are assigned to the East Region. Since East Region loads are forecast to grow faster than the West Region loads, more new generation, both baseload and peaking, is anticipated in the East Control Area.

Transmission plant and firm transmission wheeling are allocated on a rolled-in basis to all states using the average of the 12 monthly coincident peak loads. This is consistent with the allocation used by the FERC in setting transmission rates for most utilities, including PacifiCorp. Allocating transmission on a rolled-in basis enables the Company to preserve the benefits of the integrated system operations.

System balancing purchases and sales include all short-term non-firm hourly wholesale transactions. System balancing transactions bring loads and resources into balance in each portion of the system and reflect the Company's ability to take advantage of opportunities related to price differences between market hubs.

The interchange accounting methodology values and allocates the costs and revenues associated with system balancing purchases/sales and interchanges deemed to be made between the two regions. The methodology estimates the volumes by netting each region's load, resources, assigned long-term and short-term firm wholesale transactions, and short-term non-firm balancing transactions. After accounting for system balancing transactions, the residual of transactions are deemed to be interchange transactions.

Market prices are used to indicate the value of the "at arm's length" interchange transactions for both the buyer and the seller. Specifically, the methodology prices interchange at the average of the seller region's highest market price and the buyer region's lowest market price. Averaging the two allows the control areas to split the savings from the system as a whole.

The Hybrid Method is the result of several multi-state staff meetings/workshops, many conference calls, and a significant modeling effort on the part of the Company. Many other options were explored. For example, before determining the appropriate interchange accounting methodology, three different accounting methods were thoroughly explored along with three different pricing approaches. Appendix D includes a summary of how major issues are treated under the Hybrid Method as well as a list of concessions made by the Oregon Coalition in developing the method.

2. Benefits of the Hybrid Method

The benefits are due to the separation of control areas for cost allocation purposes. Separating the control areas:

1. Reduces the MSP issues at the system level to asset assignment and transfer price;
2. Eliminates the issue of the slower growing West side states subsidizing the higher load growth on the East side;
3. Is consistent with PacifiCorp's current operating practices;
4. Eliminates the Hydro Endowment issue;
5. Aligns states with similar views on policy issues, including open access and fixed vs. dynamic allocations;
6. Places all special contracts, including costs and benefits of the terms and provisions, in the control area in which the state approving the contract is located. (Essentially all of the special contracts would be assigned to the East Control Area.)
7. Provides for fixing of resources on a control area basis;
8. Eliminates issue regarding Direct Access in Oregon potentially impacting East side jurisdictions;
9. Allows resource subscription to occur on a control area basis;

10. Allows each control area can pursue its own DSM policies and bear the costs and benefits of those policies; and

11. Apportions dam relicensing costs clean air costs to the Control Area to which the resource giving rise to the costs is assigned.

The rate impacts of the Hybrid Method are summarized in Table 5.

Table 5: Forecasted Revenue Requirements using the Hybrid Method

Revenue Requirement - $Millions

		2005-2018 NPV	2005	2008	2011	2014	2018
Oregon	Hybrid	8,157	810	992	1,097	1,173	1,243
	Protocol	8,345	836	988	1,106	1,220	1,300
	Modified Accord	8,316	841	997	1,098	1,197	1,273
	Rolled-In	8,350	852	1,001	1,100	1,201	1,280
	"Fair Share"	8,333	846	999	1,099	1,199	1,276
Utah	Hybrid	14,356	1,240	1,596	1,918	2,238	2,619
	Protocol	14,183	1,225	1,609	1,906	2,180	2,550
	Modified Accord	14,233	1,217	1,596	1,919	2,218	2,592
	Rolled-In	14,180	1,201	1,589	1,915	2,212	2,582
	"Fair Share"	14,206	1,209	1,592	1,917	2,215	2,587

Comparison to "Fair Share" - $Millions

Oregon	Hybrid	-176	-36	-7	-2	-26	-33
	Protocol	12	-10	-11	7	21	24
	Modified Accord	-17	-5	-2	-1	-2	-3
	Rolled-In	17	6	2	1	2	4
Utah	Hybrid	150	31	4	1	23	32
	Protocol	-23	16	17	-11	-35	-37
	Modified Accord	27	8	4	2	3	5
	Rolled-In	-26	-8	-3	-2	-3	-5

Fair share was the result of PacifiCorp's method in its Structural Realignment Proposal in Docket UM 1001. The proposal was intended to affect each PacifiCorp jurisdiction somewhat equally from the existing disparate state allocation methods.

B. Dynamic Alternative

In the event the Commission chooses not to adopt the Hybrid Method, the Coalition proposes a second, but less preferable alternative. This proposal dynamically allocates costs across all jurisdictions, but assigns the costs of new resources to incremental, rather than the total, load. Assigning the costs of new resources to incremental load better insulates slower growing states from the increased costs associated with meeting faster growing states' load. Also, the Coalition-supported dynamic alternative (Dynamic Alternative) applies load decrements to a hydro endowment to ensure that both the costs and the benefits of the hydro endowment are assigned to the Northwest.

The Dynamic Alternative makes several changes to PacifiCorp's Protocol. These changes are necessary to meet the objectives of the Coalition and the Commission. The major changes include:

1. The assignment of QF contracts on a state situs basis with a load decrement;
2. A hydro endowment consisting of the Company-owed hydro resources and including its Mid-C contracts, is implemented with a load decrement; and
3. The costs of incremental resources are assigned to states based on each state's incremental load.

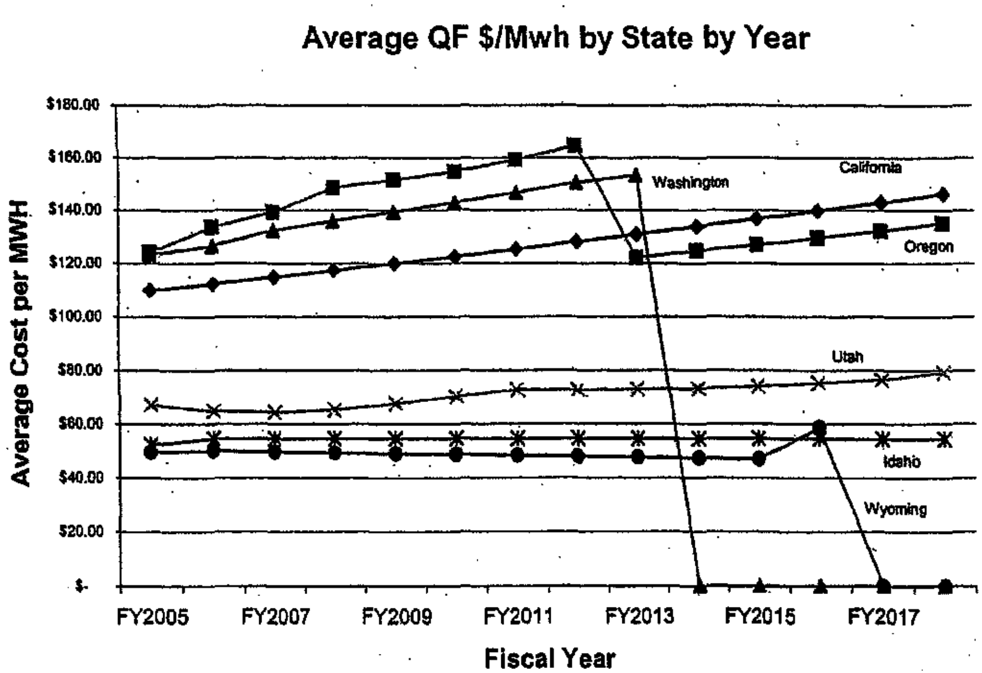
This dynamic method of determining cost allocation factors for incremental resources is supported by the Coalition based on the understanding that this method is only used to determine state allocations. Rate design should be determined separately from state allocations. The Coalition agrees that if the Commission should adopt the Coalition's dynamic method, the Coalition members will not use or cite such adoption as the basis for support of using this methodology in establishing rates among the various rate classes. Further, the Coalition recommends the Commission find that adoption of the Coalition's methodology is solely for purposes of jurisdictional allocations.

1. QF Contracts

Currently the costs of Qualifying Facilities (QFs) contracts are spread across PacifiCorp's system. The Protocol similarly assigns the costs of QF contracts across the states. In the Dynamic Alternative, the Coalition modifies the Protocol so that QF contracts are assigned situs with a load decrement. The effect of assigning the costs of the QF contracts on a situs basis increases Oregon's revenue requirement by $104M (NPV 2005-2018). However, treating QF contracts as state situs is consistent with our recommended principles.

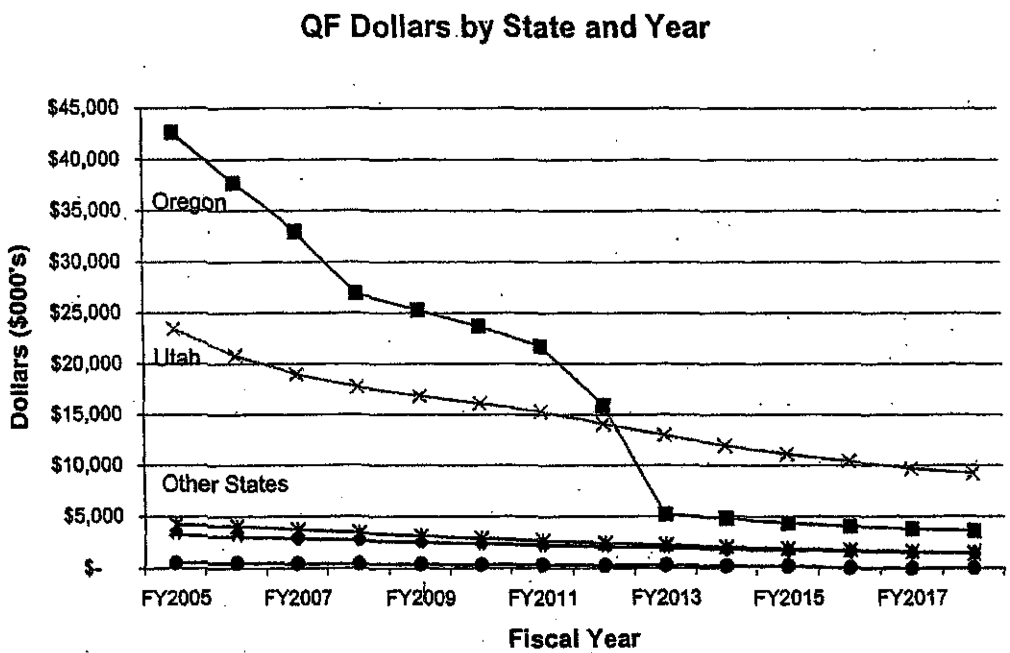
The Company is required by federal law to purchase any and all power offered by the QF at prices established by the state within which the QF is located. Each state independently determines the purchase prices, which are typically called, avoided costs. Chart 1 illustrates the average prices established by each state for existing QF contracts.

Chart 1



In addition to allocating the costs of the QF power by the state to which the QF is located, the retail load served by the Company should also be decremented by the amount of QF power. In this way, both the benefits and costs of the QF power are assigned by state. Oregon currently has more QF power than most other PacifiCorp states and the avoided costs are relatively high. Chart 2 shows the total QF dollars associated with each state's QF purchases.

Chart 2



As noted above, Situs assignment of QF contracts increases costs allocated to Oregon from those currently assigned in rates. *See* Appendix E; Summary of QF's Costs, Mwh and Average Cost per Mwh.

2. Hydro Endowment

The Protocol assigns the cost of the hydroelectric resources, including the Mid-C contracts to the states that originally possessed the resources prior to the Utah Power &

Light and Pacific Power & Light Merger. The Protocol also assigns an amount of power generating capability equivalent to the hydro resources (the Huntington resource) and its costs to the Utah Power & Light states. The benefit to Oregon is not being assigned Huntington costs. The benefit to the Utah Power & Light states is not being assigned the hydroelectric costs.

Thus, in the Protocol, Oregon's hydro resource benefits are directly comparable to the costs of the Huntington resources. This treatment does not capture the economic benefits of the hydroelectric resources, but merely allocates to Oregon the costs of the resources.

The Coalition's Dynamic Alternative assigns the former Pacific Power & Light states both the benefits and the costs (such as relicensing) of the Company owned hydroelectric resources and the Mid-C contracts. This is accomplished by assigning the costs directly to the respective Pacific Power & Light states (still being served, as Montana and Idaho service territories have been sold) and decrement the respective loads of those states by the expected shape and amount of power available from such resources.

The Company's owned resources and the Mid-C contracts should not be treated differently with respect to jurisdictional allocations. The Company's original Mid-C contracts, for all purposes, look like ownership shares since the utility has rights to its percentage share of any and all power available from the resources, is responsible for its share of the costs of the resources, and the contract terms match the life of the hydroelectric license. Recently some of the contracts have been renegotiated because the facility licenses were up for renewal. These new contracts still provide PacifiCorp with power at prices well below market. These power contracts would not be available to any utility that was not an original participant, directly or indirectly, in the hydroelectric projects.

To determine the appropriate peak and energy load decrement to match with the assignment of the hydroelectric resources under the Dynamic Alternative, the Company will run its power cost models, including all loads and resources (including hydroelectric resources), to obtain the economic dispatch of those resources. Once the dispatch is known, the respective divisional hourly loads are reduced by the hourly output from the hydroelectric resources.

The Coalition has not yet taken a position yet on the allocation of the value of the reserves provided by the hydroelectric resources, such as spinning and non-spinning reserves. The value of reserves could be tied with the assignment of hydroelectric resources or spread system wide.

3. Treatment of New Resources

For the most part, the Protocol assigns the costs of new resources to states based on the overall percentage of total load that each state represents. (There are some minor modifications to this method, including assigning costs for seasonal resources and uneconomic state resources.) This method of assigning costs works well if each state has grown, and is expected to continue to grow, at comparable rates. This method of assigning costs is problematic if states grow at diverging rates. In the case where incremental plants are more expensive than embedded resources, the Protocol method of assigning costs shifts costs more appropriately borne by a faster growing state to the other, slower growing states.

This Coalition's Dynamic Alternative dynamically allocates costs across all jurisdictions but assigns the costs of new resources to incremental load, rather than the total load. This proposal also has the benefit of providing the appropriate pricing signals to each state with respect to the value of conservation and renewable resources. If a state acquires conservation, the state's loads will be reduced and as will its allocation of the newer pool of resource costs. Under the Protocol, the state would benefit only from changes in the average cost of all generation; that is, blending both new higher cost resources and older lower cost resources.

The Coalition is exploring the following method for assigning the costs of base and incremental resources.

Power Resource Cost Allocation Method

1. Base Loads: FY 2002 loads, normalized for weather and adjusted for contracts that terminate and generation plants that retire after FY 2002, are the basis of Base System Resource Allocators.

2. Incremental Loads: Post-FY 2002 loads (LT-LFY 2002), are used as basis for Incremental Resource Allocators.

3. Base Resources: all "System" generating plants and wholesale contracts defined in Protocol: - existing resources (contracts and owned generation) at end of March 2002.

4. Cholla/APS: treat as "Seasonal Resource."

5. Incremental Resources: Post-FY 2002 generating plants and wholesale power contracts.

6. Hydro Endowment and QFs: System hydro and Mid-C costs assigned to Oregon, Washington and California; QFs contract costs assigned on state situs basis; Hydro endowment resources and QFs output are decremented from Base Loads to determine Base System Resource Allocators.

7. Base Resource Retirements: Reduce Base Loads by the MWh lost when generation is retired or purchase power contracts expire.
8. Base Wholesale Sales Contracts: Increase Base Loads by the MWh gained when wholesale sales contracts expire.

9. Refurbishments: Costs assigned to refurbished Base or Incremental Resources

10. Replacement Costs for Large Unexpected Plant Outages: Assigned to states based on whether plant was Base or Incremental resource.

11. Replacement Costs for Large Unexpected Plant Outages: Assigned to states based on whether the plant was Base or Additional resource.

4. Direct access

Direct access could be handled under the Dynamic Alternative by calculating stranded costs or benefits for any direct access consumer based on the resources as of FY 2002. That is, for any Oregon consumer that chose direct access, those loads would continue to be treated as PacifiCorp loads for interjurisdictional purposes. This calculation would apply even if the consumer permanently chose direct access post FY

2002. Stranded costs or benefits would not be assumed to occur from any new resource post FY 2002. In addition, direct access consumers who permanently leave PacifiCorp post FY 2002 would not have their loads included for state jurisdictional allocation purposes. This concept has the benefit of simplifying the handling of stranded costs for interstate jurisdictional purposes. More consideration of this concept is needed to ensure that non-direct access consumers within Oregon would not be harmed through its implementation.

IV. COMPARISON OF PROPOSALS

A comparison of the two Coalition proposals (the Hybrid Method and the Dynamic Alternative) and the Protocol is included as Appendix A.

MSP Alternatives - Treatment of Issues

	Issue	PacifiCorp's Protocol	Staff's Hybrid	Staff's Dynamic Alternative
Base Resources and Loads	Existing Resources at end of March 2002	Dynamic Rolled-in, coal and hydro endowment offsets	All plants and contracts are assigned to the CAs	Dynamic Rolled-in except System Hydro, Mid-C and QF contracts
	Base System	Dyanmic Rolled-in, SG factor	See Above	Dyanmic Rolled-in, SG factor (adjusted FY 2002 load)
	Base Seasonal (simple cycle CTs)	Dyanmic Rolled-in, allocation based on hours of operation	See Above	Dyanmic Rolled-in, SG factor (adjusted FY 2002 load)
	Base State	Dynamic Rolled-in, other states' dissallowances assigned to State who created the resource.	See Above	Dyanmic Rolled-in, SG factor (adjusted FY 2002 load)
	Base Pre-merger thermal	Rolled in except for coal endowment	See Above	Dyanmic Rolled-in, SG factor (adjusted FY 2002 load)
Incremental Resources and Loads	Incremental Resources, post March 2002	See Below	Assigned to control area with potential exceptions based on IRP and/or RFP results	Dynamic Rolled-in, SG factor (load incremental to FY 2002)
	System	Dyanmic Rolled-in, SG factor	See Above	Dynamic Rolled-in, SG factor (load incremental to FY 2002)
	Seasonal (simple cycle CTs)	Dyanmic Rolled-in, allocation based on hours of operation	See Above	Dynamic Rolled-in, SG factor (load incremental to FY 2002)
	State	Dynamic Rolled-in, other states' dissallowances assigned to State who created the resource.	See Above	Dynamic Rolled-in, other states' dissallowances assigned to State who created the resource. Both the power and cost is assigned to the state. Includes a load decrement.
	All Resources			
	Transmission classification (T/D)	Retain current classification of transmission assets	Retain current classification of transmission assets	Retain current classification of transmission assets
	Access to Markets	Full Access	East has Mid-C market = lesser of 78% of AMPs line capacity or 100% of System balancing transactions at Mid-C	Full Access
	Special Contracts	Situs assignment of special contract revenues and load; value of ancillary services determined by the Commission with jurisdiction and allocated system-wide by SG factor	Situs assignment of special contract revenues and load; value of ancillary services determined by the 3rd party, cost of ancillary services allocated to the CA	Same, except value of ancillary services determined by independent 3rd party, paid for by Company; cost of ancillary services allocated to CA
	SCE Contract	Rolled In	50% of revenues and costs assigned to each CA	Base tier contract
	Cholla/APS	Treated as seasonal resource	Assigned to East CA	Treated as seasonal (Base) resource
	Exchange Contracts	Not needed	Both receipts and deliveries of power are assigned to CA with delivery responsibility; return energy fills any CA short position first, with any excess sold at the highest market and revenue credited to delivering CA	Not needed
	Value of Operating Reserves	Not needed	Reserves provided to the East by West hydro resources are priced at the Company's FERC OV-11 tariff; credit to East for PPL-Wyoming portion	Not needed
	Transfer Pricing/Interchange Accounting	Not needed	Interchange calculated after system balancing transactions are assigned or allocated, and priced at average of seller's market max and buyer's market min	Not needed
	Within Region Allocation	N/A	Dynamic, Rolled-in	N/A
	System Hydro	Fuel offset, no load decrement	Assigned to Control area , dynamic allocation	Assigned to PPL states, load decrement
	Mid-C Contracts	Fuel offset, no load decrement	Assigned to Control area , dynamic allocation	Assigned to PPL states, load decrement
	Coal Endowment	Huntington costs assigned to UPL states, no load decrement	N/A -- All plants are assigned to CA	N/A -- All Plants assigned to appropriate tier
	QFs	Treated as System Resource (See Above)	Assigned to Control area , dynamic allocation	Assigned situs, load decrement
	Direct Access	Metered Load used to set allocation factors	Metered load used to set allocation factors within CA. For new resources and power purchase agreements with fixed costs, the SG factor would not include direct access loads	Metered load used to set allocation factors within CA. For incremental resources and power purchase agreements with fixed costs, the SG factor would not include direct access loads
	DSM	Costs assigned situs, benefits allocated system-wide	Costs assigned situs, benefits allocated system-wide	Costs assigned situs, benefits allocated system-wide
	Sales for resale firm	Allocated on SG factor	Allocated within region	Assigned to Base and incremental tiers, allocated system-wide
	Sales for resale non-firm	Allocated on SE factor	Allocated within region	Assigned to Base and incremental tiers, allocated system-wide
	East - West Load Split	N/A	by Control Area(CA): East - Idaho, Utah, Wyoming; West - California, Oregon, Washington	N/A
	East - West Existing Resource Split	N/A	Pre-merger generation and contracts assigned by CA; Post-merger by POD/CA	N/A
	Dave Johnston & Wyodak Adjustment	N/A	None	N/A

Estimated Impact on Oregon of Increasing Utah's Loads by 1% and of Utah's Load Growth Being Greater Than the Non-Utah Average

Year	(a) Load Forecasts (MWa) Non-UT	(b) Load Forecasts (MWa) UT	(c) Load Forecasts (MWa) UT + 1%	(d) System's burden from UT+1% ($x1000)	(e) Under Base Case Protocol: Utah's burden from UT+1% ($x1000)	(f) Under Base Case Protocol: Oregon's burden from UT+1% ($x1000)	(g) UT load given non-UT growth (MWa)	(h) Ratio of UT's load increase above non-UT growth level vs load plus 1%	(i) Oregon's burden from UT's higher growth rate ($x1000)	(j) Oregon's Base Case Rev Req under Protocol ($x1000)	(k) Oregon's burden from UT's higher growth rate (%)
2004	3608	2540									
2005	3686	2682	2709	9,060	8,055	530	2577	3.91	2,071	835,969	0.25
2006	3703	2788	2816	9,867	8,976	469	2615	6.21	2,912	883,184	0.33
2007	3745	2899	2928	12,569	10,771	949	2653	8.48	8,047	938,157	0.86
2008	3800	3022	3052	13,079	11,461	852	2692	10.92	9,303	988,212	0.94
2009	3838	3133	3164	14,841	12,811	1024	2731	12.82	13,125	1,037,725	1.26
2010	3856	3253	3286	16,038	13,781	1134	2771	14.80	16,789	1,082,605	1.55
2011	3908	3373	3407	15,652	13,902	886	2812	16.63	14,737	1,108,373	1.33
2012	3983	3501	3536	15,844	14,473	692	2853	18.51	12,806	1,153,228	1.11
2013	4049	3612	3648	16,237	14,828	711	2895	19.85	14,116	1,191,990	1.18
2014	4126	3733	3770	16,602	15,241	684	2937	21.32	14,580	1,220,183	1.19
2015	4174	3855	3894	17,260	15,750	769	2980	22.69	17,450	1,245,167	1.40
2016	4264	3991	4031	17,742	16,280	744	3024	24.23	18,029	1,277,503	1.41
2017	4336	4112	4153	18,479	16,981	759	3068	25.39	19,268	1,307,272	1.47
2018	4422	4252	4295	19,272	17,711	785	3113	26.79	21,027	1,300,087	1.62
	1.46%	3.75%		$111,844 8.823% NPV	$99,920 8.823% NPV	$6,115 8.823% NPV	1.46% Average Growth Rate		$89,745 8.823% NPV	$8,346,647 8.823% NPV	1.08 8.823% NPV
	Average Growth Rates			$161,093 2% NPV	$162,522 2% NPV	$9,491 2% NPV			$154,415 2% NPV	$13,318,854 2% NPV	1.16 2% NPV

Conclusions from the Fourteen-Year Modeling Period (Employing Base Case Protocol)

		8.823% NPV	2% NPV
(1)	Utah's percentage share of increased costs of its load being 1% greater than projected:	89%	90%
(2)	Oregon's percentage share of cost of Utah's load being 1% greater than projected:	5.5%	5.2%
(3)	Increased cost to Oregon of Utah's growth rate exceeding the non-Utah system average (x1000):	$89,745	$154,415
(4)	Percentage rev. req. increase in Oregon due to Utah's growth rate exceeding the non-Utah system average:	1.08%	1.16%

Sources, formulas, assumptions:

(a), (b), (d), (e), (f), (j): PacifiCorp data replicated in OPUC Staff study.
(c): (b) x 1.01
(g): {(b-1) x 1.0146}, where (b-1) is the previous year's value of (b) and 1.46% is the average non-Utah system forecasted load growth rate.
(h): {(b)-(g)} / {©-(b)}
(i): (h) x (f) Assumption: There is a linear relationship between the increase in Utah's loads and the cost burden of those increases that are borne by Oregon.
(k): {(i) / (j)} x 100

(1): {Column (e) NPV} / {Column (d) NPV} (89% was the bottom-line answer supplied by PacifiCorp to OPUC Staff Data Request No. 15)
(2): {Column (f) NPV} / {Column (d) NPV}
(3): Column (i) NPV
(4): {Column (i) NPV} / {Column (j) NPV}

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CUB Data Request No. 3

CUB Data Request No. 3

The proposed protocol (Section VIII) states that the Commission with jurisdiction over a Special Contract will make a determination of the fair market value of a Customer Ancillary Service Contract attributes of a Special Contract.

A. Before this filing the Company represented that if the Oregon Commission disagreed with another Commission's determination of fair market value, it would be free to disallow those costs as imprudent. Such a right is critical to insure that states do not overvalue ancillary services in order to shift the cost of economic development to other states. Why was the decision made to not incorporate this critical feature from the protocol?

B. Section XIII of the protocol require that "prior to departing from the terms of the Protocol" any Commission "will endeavor to cause their concerns to be presented at meetings of the MSP Standing Committee and interested parties from all States..." Because the Protocol delegates the decision over the fair market value of the special contract to the host state, wouldn't a decision by the Oregon Commission setting a separate fair market value be considered "departing from the terms of the Protocol?

C. If PacifiCorp signs a special contract with an industrial customer, but the host state decides that the fair market value of the ancillary services is significant higher than PacifiCorp proposed, what options would the Oregon Commission have to disallow costs under the protocol if Oregon believes that the Company valued the ancillary services correctly, but that the host state inflated that value? If such a disallowance must be based on imprudence, how in this scenario was PacifiCorp imprudent?

Response to CUB Data Request No. 3

A. The Protocol does allow a Commission to disagree with another Commission's determination of fair market value in that the Protocol does not alter a Commission's authority to determine that specific PacifiCorp costs were imprudent. PacifiCorp would not agree that a Commission is 'free' to make such findings; a decision that a particular cost was imprudent must be based on sufficient evidence. Under the Protocol, each Commission agrees that it will determine discounts for Customer Ancillary Service Attributes based on a finding of the fair market value of those attributes and not based on economic development or other considerations. Commissions agree that they will accept situs allocation of discounts which are greater than the fair market value of Customer Ancillary Service Attributes. A Commission approving a Special Contract with discounts for Customer Ancillary Service Attributes should make a

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finding regarding the fair market value of those Attributes. Other Commissions should give weight to those findings but are not bound by them.

B. If the Oregon Commission were to disagree with another Commission regarding the fair market value of Customer Ancillary Service Attributes, the Oregon Commission would not be departing from the terms of the Protocol. Such a conclusion would not, by itself, require the prior approval of the MSP Standing Committee. As a corollary to this hypothetical Commission conclusion, however, the Oregon Commission would presumably be concluding that the Commission that approved the contract had not, in fact, based the discount on the fair market value of the Customer Ancillary Service Attributes. The disagreement between the two states would represent an issue of interpretation of the Protocol that may be taken before the MSP Standing Committee by PacifiCorp or another party to the MSP process.

C. In the given example PacifiCorp would not be imprudent. The Oregon Commission should, in this example, bring an issue of interpretation before the MSP Standing Committee. PacifiCorp hopes and expects that this situation will not occur frequently. PacifiCorp expects the Protocol to substantially reduce disagreements regarding special contract discounts because it would clarify the standards used to judge the circumstances under which discounts should be allocated system-wide. Previously, all discounts for interruptible contracts were allocated system-wide whether or not a Commission had made a finding regarding the value of the interruptibility.

MSP - Hybrid Assumptions

Issue	Hybrid Treatment
East - West Load Split	by Control Area(CA): East - Idaho, Utah, Wyoming; West - California, Oregon, Washington
East - West Existing Resource Split	Pre-merger generation and contracts assigned by CA; Post-merger by POD/CA
Dave Johnston & Wyodak Adjustment	None
New Resources	Assigned to CA
Transmission classification (T/D)	Retain current classification of transmission assets
Access to Markets	East has Mid-C market = lesser of 78% of AMPs line capacity or 100% of System balancing transactions at Mid-C
Special Contracts	Situs assignment of special contract revenues and load; value of ancillary services determined by independent 3rd party, paid for by Company; cost of ancillary services allocated to CA
SCE Contract	50% of revenues and costs assigned to each CA
Cholla/APS	Assigned to East CA
Exchange Contracts	Both receipts and deliveries of power are assigned to CA with delivery responsibility; return energy fills any CA short position first, with any excess sold at the highest market and revenue credited to delivering CA
Value of Operating Reserves	Reserves provided to the East by West hydro resources are priced at the Company's FERC OV-11 tariff; credit to East for PPL-Wyoming portion
Transfer Pricing/Interchange Accounting	Interchange calculated after system balancing transactions are assigned or allocated, and priced at average of seller's market max and buyer's market min
Within Region Allocation	Dynamic, Rolled-in

Concessions included in above Hybrid treatment of issues:

- no recognition of CA pre-merger plant cost and size differentials
- includes of credit to East CA for PPL-Wyoming portion of reserves provided by pre-merger West Hydro Resources
- includes higher %. assignment of AMPs line capacity to the East CA
- includes of 50-50 split of SCE contract, when an argument can be made for a West-95%/East-5% split
- with largest Exchange contract in the East, selling excess return energy at highest market provides benefits to East

Appendix D

Summary of QF's Costs, Mwh and Average Cost per Mwh
(Based on Response to OPUC Data Request 6a)

State	FY2005	FY2006	FY2007	FY2008	FY2009	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018
California														
QF Dollars	$ 3,486.00	$ 3,566.00	$ 3,645.00	$ 3,726.00	$ 3,809.00	$ 3,893.00	$ 3,980.00	$ 4,068.00	$ 4,159.00	$ 4,252.00	$ 4,347.00	$ 4,444.00	$ 4,543.00	$ 4,644.00
Total MWH	31,790	31,790	31,790	31,790	31,790	31,790	31,790	31,790	31,790	31,790	31,790	31,790	31,790	31,790
$/MWH	$ 109.73	$ 112.16	$ 114.65	$ 117.20	$ 119.80	$ 122.47	$ 125.19	$ 127.96	$ 130.83	$ 133.76	$ 136.73	$ 139.78	$ 142.91	$ 146.10
14 Year NPV QF Dollars	$ 30,841.70													
Oregon														
QF Dollars	$ 46,378.00	$ 44,646.00	$ 42,470.00	$ 37,761.00	$ 38,537.00	$ 39,340.00	$ 39,225.00	$ 31,233.00	$ 11,066.00	$ 11,222.00	$ 10,910.00	$ 11,140.00	$ 11,376.00	$ 11,615.00
Total MWH	373,506	334,360	305,208	254,466	254,456	254,466	246,486	189,843	90,666	89,995	85,977	85,977	85,977	85,977
$/MWH	$ 124.17	$ 133.52	$ 139.15	$ 148.35	$ 151.44	$ 154.60	$ 159.14	$ 164.52	$ 122.05	$ 124.70	$ 126.89	$ 129.57	$ 132.30	$ 135.09
14 Year NPV QF Dollars	$ 252,389.46													
Washington														
QF Dollars	$ 2,624.00	$ 2,693.00	$ 1,856.00	$ 1,903.00	$ 1,952.00	$ 2,003.00	$ 2,055.00	$ 2,107.00	$ 1,834.00	$ -	$ -	$ -	$ -	$ -
Total MWH	21291	21291	14013	14013	14013	14013	14013	14013	11957	-	-	-	-	-
$/MWH	$ 123.24	$ 126.49	$ 132.42	$ 136.63	$ 139.33	$ 142.93	$ 146.61	$ 150.40	$ 153.35	$ -	$ -	$ -	$ -	$ -
14 Year NPV QF Dollars	$ 13,032.58													
Utah														
QF Dollars	$ 25,475.00	$ 24,655.00	$ 24,476.00	$ 24,859.00	$ 25,676.00	$ 26,677.00	$ 27,606.00	$ 27,693.00	$ 27,705.00	$ 27,814.00	$ 28,125.00	$ 28,675.00	$ 29,065.00	$ 30,106.00
Total MWH	380,000	380,000	380,000	381,105	380,000	380,000	380,000	381,105	380,000	380,000	380,000	381,105	380,000	380,000
$/MWH	$ 67.04	$ 64.88	$ 64.41	$ 65.23	$ 67.57	$ 70.20	$ 72.65	$ 72.67	$ 72.91	$ 73.19	$ 74.01	$ 75.24	$ 76.54	$ 79.23
14 Year NPV QF Dollars	$ 208,470.33													
Idaho														
QF Dollars	$ 4,676.00	$ 4,777.00	$ 4,777.00	$ 4,777.00	$ 4,777.00	$ 4,777.00	$ 4,777.00	$ 4,777.00	$ 4,777.00	$ 4,772.00	$ 4,771.00	$ 4,771.00	$ 4,727.00	$ 4,495.00
Total MWH	87,408	87,651	87,651	87,651	87,651	87,651	87,651	87,651	87,651	87,560	87,530	87,530	86,811	82,555
$/MWH	$ 52.34	$ 54.50	$ 54.50	$ 54.50	$ 54.50	$ 54.50	$ 54.50	$ 54.50	$ 54.50	$ 54.51	$ 54.51	$ 54.51	$ 54.45	$ 54.45
14 Year NPV QF Dollars	$ 37,272.45													
Wyoming														
QF Dollars	$ 597.00	$ 602.00	$ 598.00	$ 594.00	$ 590.00	$ 586.00	$ 581.00	$ 577.00	$ 574.00	$ 570.00	$ 566.00	$ 84.00	$ -	$ -
Total MWH	12,048	12,048	12,048	12,046	12,048	12,048	12,048	12,048	12,048	12,048	12,048	1,434	-	-
$/MWH	$ 49.55	$ 49.97	$ 49.63	$ 49.30	$ 48.97	$ 48.64	$ 48.22	$ 47.89	$ 47.64	$ 47.31	$ 46.98	$ 58.58	$ -	$ -
14 Year NPV QF Dollars	$ 4,065.42													

MEMORANDUM

February 24, 2004

TO: MSP PARTICIPANTS

FROM: GEORGE GALLOWAY AND JUSTIN BOOSE

RE: Mid-Columbia Hydroelectric Projects

This memorandum discusses the history of the four non-federal Mid-Columbia Hydroelectric projects that include the Priest Rapids dam, Wanapum dam, Wells dam and the Rocky Reach dam and the nature of PacifiCorp's entitlement to power from the projects.

I. Priest Rapids Project

A. *Basic Project Description*

The Priest Rapids Project consists of two separate but adjacent dams (Priest Rapids and Wanapum) located in central Washington on the Columbia River upstream from the Hanford Nuclear Reservation and owned and operated by Grant County PUD No. 2 ("Grant County")[1]. The Priest Rapids dam, consisting of ten power generation units with a total nameplate capacity of 788.5 MW, was constructed between August 1956 and September 1961. It was financed with a June 1959 bond issuance of $166 million covering 49.5 years at 3.98 percent interest.

The Wanapum dam, consisting of ten power generation units with a total nameplate capacity of 831.25 MW was financed with a June 1959 bond issuance of $195 million for 50 years at 4.9 percent interest. Construction occurred between January 1959 and September 1963.

The Priest Rapids Project was originally planned by the US Army Corp of Engineers as part of a comprehensive plan for flood control, navigation and power production on the Columbia River in response to the disastrous Vanport flood of 1948. In the Flood Control Act of 1950, Congress authorized the Corp of Engineers to proceed with the project.[2] Subsequently, the project was discontinued by the federal government because funds for its construction were not appropriated by Congress.

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[1] Except as indicated otherwise, references herein to the Priest Rapids Project include both dams.

[2] *See* Section 204 of the Flood Control Act of 1950 (Public Laws 516, Laws of the 81st Cong, 2d Sess, c 188, 64 Stat 170, 179).

B. Background History

In 1952, Grant County applied to the Federal Power Commission ("FPC")[3] for authority to pursue development of the project. In 1954, Congress enacted Public Law 544,[4] which amended the Flood Control Act of 1950 to permit Grant County to undertake construction and operation of the project. Section 6 of Public Law 544 requires Grant County to "offer a reasonable portion of the power capacity and a reasonable portion of the power output of the project for sale within the economic market area in neighboring States."

In 1955, Grant County obtained a 50-year license from the FPC to construct and operate the Priest Rapids Project.[5] The license incorporates the requirements of Public Law 544, as well as the Federal Power Act, and contains various non-power related provisions and requirements.

C. Project Financing and Disposition

Grant County financed the costs of construction by issuing separate revenue bonds for each project. Initially, Grant County bore the construction "dry hole" risk associated with the project, with the understanding that revenues from power sales would be used to repay the bonds.[6] At the time, there were no disputes concerning entitlement to output from the projects. To the contrary, there was concern as to whether adequate interest from potential purchasers would exist to support the financial obligations being undertaken by Grant County:

> "In 1954, when Pub. L. 83-544 was enacted, there was no concern or controversy over how to limit access to the proposed project's power. The proposed Priest Rapids Project would be capable of generating an enormous amount of power in relation to its potential service territory. The focus of the project's advocates was on securing enough customers for the project's output to ensure its

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[3] The FPC is the predecessor to the Federal Energy Regulatory Commission ("FERC").

[4] Public Law 83-544, Laws of 83rd Cong, 2d Sess, c 589, 68 Stat 573.

[5] Project License No. 2114, 14 FPC 1067, 1955 WL 3223 (1955).

[6] Priest Rapids FERC License Renewal Application (Oct. 2003) at 6.

> financing and construction; no one was focusing on how to restrict potential customers. Indeed, in that era the developers of the Priest Rapids Project actively sought (unsuccessfully) to enlist customers in Idaho".[7]

The pool of prospective purchasers was limited by existing transmission technology, which limited the effective transmission range to 250 miles from the project.[8] In 1955, Grant County sent solicitations to various potential purchasers in the Pacific Northwest, consisting of seven investor owned utilities, eight municipalities, eighteen public utility districts, the Northwest Public Power Association, and to rural electric cooperatives and grange associations in Oregon, Washington, and Idaho.[9]

Concurrent with the first bond issuance for the Priest Rapids dam in 1956, Grant County entered into twelve power sales contracts with the owners of various public and private electric utility systems, including PacifiCorp, whereby the purchasers each agreed to purchase a percentage share of the output of the Priest Rapids dam (63.5 percent in total) in exchange for paying a proportionate share of the project costs. The purchasers also received options to purchase a proportionate share of the output from the Wanapum dam when constructed. Ultimately, nine of the original purchasers, including PacifiCorp, exercised options to acquire a share of the output from the Wanapum Dam. The Priest Rapids agreements expire in 2005, and the Wanapum agreements in 2009.

Grant County retained 36.5 percent of both projects for its own power needs. The percentage allotments among the purchasers were "carefully determined by [Grant County's] engineers based upon the productivity of the development in attempted compliance with the

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[7] *See Kootenai Electric Cooperative et al.*, 82 FERC ¶ 61,112 at 61,401 (1998).

[8] *Id.* at 61,399.

[9] *Id.* at 61,401 n 91.

[reasonable portion] requirement of Public Law 544."[10]

D. *Priest Rapids Litigation*

In 1995, a group of Idaho power cooperatives filed a complaint with FERC seeking entitlement to a share of the capacity and output from the Priest Rapids Project in connection with the upcoming relicensing of the project. They claimed entitlement to a portion of the project output in accordance with Section 6 of Public Law 544.[11] The complaint proceeding focused on the meaning of the phrases "reasonable portion" and "economic market area in neighboring states" as used in that legislation.

FERC determined that Congress intended the grant of entitlement under PL-544 to be inclusive rather than exclusive. Although the statute refers to "neighboring states," the legislative history is full of references indicating that the projects should benefit purchasers broadly throughout the Pacific Northwest.[12] FERC equated the project's "economic market area" as extending to interested purchasers throughout the region generally:

> "Thus, even if, *arguendo*, Washington, Utah, Wyoming, and Nevada were determined to be outside the scope of the "*other* states in the economic marketing area" within the meaning of Section 6, there is nothing in Section 6 or anywhere else in the statute or its legislative history that would *preclude* us from allowing power marketing agencies in those states from participating in the allocation of power from the project as long as the power marketing agencies in the other states were to receive a "reasonable portion" of that power. [Emphasis supplied] [13]

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[10] *Merritt-Chapman & Scott Corp. v. Public Utility Dist. No. 2 of Grant County, Wash.*, 319 F2d 94 (2nd Cir 1963), *cert den* 374 US 968 (1964). This case, involving a dispute between Grant County and the contractor that constructed the Priest Rapids dam, contains a useful background summary concerning the project's development.

[11] *See Kootenai Electric Cooperative et al.*, 82 FERC ¶61,112. Section 6 of Public Law 544 affords FERC authority, in the event of a disagreement, to "determine and fix the applicable portion of power capacity and power output to be made available."

[12] *Id.* at 61,399.

[13] *Id.* at 61,112. Apparently, investor-owned utilities were considered "power marketing agencies" as that term is used in Public Law 544.

With respect to determining a "reasonable portion" of the output to be offered for sale, FERC held that Grant County was entitled to retain 70 percent of the output for its own needs, and that the remaining 30 percent should be marketed according to market-based pricing principles with some meaningful priority available to the participants in the proceeding. Based on FERC's decision, Grant County entered into a series of contracts with the original purchasers and the Idaho cooperative that will take effect upon expiration of the original power sales agreements, assuming that a renewal license is issued to Grant County.[14] In addition to providing certain rights with respect to the 30 percent "reasonable portion," those agreements provide for sales of portions of Grant County's reserved share that exceed its requirements during the early years of the renewal term.

E. *PacifiCorp's Contractual Rights and Obligations*

PacifiCorp is party to a power sales contract dated May 22, 1956 with Grant County for a share of the Priest Rapids dam output, which expires on October 31, 2005. The agreement references Grant County's responsibility under Public Law 544 to make a reasonable portion of the output available for sale to neighboring states, and provides that purchases are being made "solely from the gross revenues of [PacifiCorp's] light and power system, for the benefit of consumers in the State of Oregon[.]"[15]

PacifiCorp currently receives 13.9 percent of the Priest Rapids dam output in exchange

[14] FERC's order was directed to any applicant for a renewal license for the Priest Rapids Project. In January, 2004, Grant filed a 39 volume, 12,000 page application for a renewal of the license in which it states that it intends to spend $790 Million on fish mitigation measures during the term of the new license. It appears that no other entity will seek to compete for the new license, but that there will be stiff opposition from fishery advocacy groups. Operations of the Project impact the Hanford reach of the Columbia River which provides spawning habitat for 80 percent of the River's fall chinook salmon run.

[15] Priest Rapids Power Sales Agreement, § 3(a).

for paying 13.9 percent of the annual power costs, defined as all costs arising from the ownership, operation and maintenance of the project.

PacifiCorp is party to a substantially similar power sales contract with Grant County for a share of the Wanapum dam output. The agreement also references Grant County's "reasonable portion" obligation under Public Law 544 and provides that purchases are being made "solely from the gross revenues of [PacifiCorp's] light and power system, for the benefit of consumers in the states of Oregon and Washington[.]"[16]

The Wanapum power sales agreement is dated June 22, 1959 and expires October 31, 2009. PacifiCorp currently receives an 18.7 percent share of the Wanapum dam output in exchange for paying 18.7 percent of the annual power costs. Both the Priest Rapids and Wanapum agreements provide PacifiCorp with a right of first refusal to purchase a proportionate share of the project output following termination of the original agreements.

In December 2001, PacifiCorp entered into three agreements with Grant County to purchase certain power products from the Priest Rapids Project upon expiration of the original power sales agreements; namely, a Product Sales Contract, an Additional Product Sales Contract and a Reasonable Portion Power Sales Contract. Each of these agreements remain in effect until the expiration of the renewal project license, if obtained by Grant County, or until such time as Grant County no longer has the authority to market output from the project.

Under the Product Sales Agreement, PacifiCorp is entitled to purchase a share of the surplus product and the displacement product from the Priest Rapids Project. The surplus product is defined as that portion of Grant County's reserved share that exceeds its load forecast. For this product PacifiCorp will pay a proportionate share of the project costs. The displacement

[16] Wanapum Power Sales Agreement, § 3(a).

product is defined as a portion of Grant County's reserved share that would be required by Grant County to meet load, but for Grant County's purchase of other displacing resources. For this product, PacifiCorp pays an amount equal to Grant County's costs for purchasing the displacing resources.

Under the Additional Product Sales Agreement, PacifiCorp is entitled to purchase a share of the non-firm generation available to Grant County from the project, in exchange for payment of a proportionate share of the project costs.

Under the Reasonable Portion Power Sales Contract, PacifiCorp pays a share of the costs associated with the "reasonable portion" of the project output, and receives a share of the proceeds from the sale of the reasonable portion by Grant County at market-based rates. PacifiCorp has the option to take energy and capacity from Grant County in lieu of the sales proceeds.

Each of the renewal agreements provides that PacifiCorp shall ensure that products it receives "are not sold, resold, distributed for use or used outside the Pacific Northwest in violation of the Bonneville Project Act, Public Law 75-329, the Pacific Northwest Consumer Power Preference Act, Public Law 88-552, the [Pacific Northwest Electric Power Planning and Conservation Act, Public Law 96-501, "Regional Act"] or in contravention of any applicable state or federal law, order, regulation or policy. If such sales occur in violation of the foregoing, [PacifiCorp] shall reimburse [Grant County] for any penalties imposed on or cost incurred by [Grant County] as a consequence of such violation."[17] However, unlike the original agreements,

[17] *See, e.g.*, Priest Rapids Product Sales Contract, § 24(a). The referenced statutes restrict the resale or distribution of BPA power by certain purchasers under certain circumstances. Pursuant to the Bonneville Project Act, preference is to be afforded to Northwest entities in acquiring BPA power and BPA is limited in its ability to sell power outside of the Region. Pursuant to Subsection 5(b) of the Regional Act, BPA is required to serve the net Regional

none of the renewal agreements state that the power would be for the benefit of consumers in particular PacifiCorp jurisdictions.[18]

II. Rocky Reach Project

A. *Basic Project Description*

The Rocky Reach hydroelectric project is located near Wenatchee, Washington and is owned an operated by Public Utility District No. 1 of Chelan County ("Chelan County"). Like Priest Rapids, the Rocky Reach project was originally planned by the Army Corp of Engineers for flood control and power production; however, it was not part of the Flood Control Act of 1950 and is not subject to the provisions of Public Law 544. The Rocky Reach project originally consisted of seven power generation units that were constructed between 1956 and 1961. It was financed by a construction bond issuance of $23.1 million in 1956 and a completion bond issuance of $250 million in 1958. An additional four generation units, were constructed between 1969 and 1971 to take advantage of stored water releases from upstream reservoirs. The addition was financed by a 1968 revenue bond issuance of $40 million. The combined total output from the project is 1213.15 MW.

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requirements of Northwest entities. The referenced statutes do not appear to apply to the renewal agreements since the power products being purchased by PacifiCorp are generated by Grant County and not by BPA. However, Grant County may have sought the provision out of a concern that if project power were deemed to be being resold outside of the Region, its entitlement to power from BPA under Subsection 5(b) of the Regional Act might be reduced. PacifiCorp has entered into various contracts with BPA, which contain restrictions on the sale or distribution of the power outside of the Region. The practice has been to conclude that as long as PacifiCorp has net loads in the Region, the contractual provisions are not violated and there is no need to track the disposition of power purchased under any particular contract. Except in respect to the residential exchange under Subsection 5(c) of the Regional Act, BPA contracts containing regional restrictions have been treated for PacifiCorp interjurisdictional cost allocation purposes as system resources.

[18] As noted above, the original Priest Rapids dam agreement states that the power is for the benefit of Oregon consumers, and the original Wanapum dam agreement states that the power is for the benefit of Oregon and Washington consumers.

B. *PacifiCorp's Contractual Rights and Responsibilities*

PacifiCorp entered into a power sales contract with Chelan County on November 14, 1957 to purchase a share of the output of the Rocky Reach project. The agreement expires on the latter of the date the project bonds are retired or 50 years from the date of commercial operation (November 1, 1961). PacifiCorp's share of the Rocky Reach project output was originally 7.1 percent and is presently 5.3 percent, representing 68 aMW. In exchange, PacifiCorp pays 5.3 percent of the project costs. Unlike the original Priest Rapids and Wanapum agreements, the Rocky Reach agreement does not state that the power being sold is for the benefit of consumers in particular PacifiCorp jurisdictions.

Chelan County operates the Rocky Reach Project pursuant to a license that expires on June 30, 2006.[19] Chelan County is pursuing relicensing and expects to file its final application for relicensing in June 2004. The power sales contract does not contain provisions expressly providing PacifiCorp with any options as to future purchases from the Rocky Reach project upon its relicensing.

[19] Project License No. 2145, 18 FPC 33, 1957 WL 3801 (1957).

III. Wells Project

The Wells project is located in Azwell, Washington and is owned and operated by Public Utility District No. 1 of Douglas County ("Douglas County"). The project consists of ten power generation units with a total capacity of 840 MW. The Wells project was completed in 1967. Unlike the Priest Rapids Project, the Wells Project was not part of the Flood Control Act of 1950 and is not subject to the provisions of Public Law 544. Douglas County operates the Wells Project pursuant to a license that expires on June 1, 2012.[20]

PacifiCorp is party to a power sales contract with Douglas County dated September 18, 1963 to purchase a share of the Wells project output. PacifiCorp purchases 6.9 percent of the project output and is responsible for 6.9 percent of the project's annual power costs. Unlike the original Priest Rapids and Wanapum agreements, the Wells agreement does not state that the power being sold is for the benefit of consumers in particular PacifiCorp jurisdictions.

The agreement expires on the latter of August 31, 2018 or the date that the project bonds are retired. PacifiCorp has an option to purchase a share of the project's output upon expiration of the power sales agreement, in proportion to its then existing share multiplied by any amounts in excess of Douglas County's requirements for providing service within its service territory.

[20] Project License No. 2149, 28 FPC 128, 1962 WL 3681 (1962).

Common Positions (Oregon Coalition/Utah DPU)

The following common issues of agreement are offered for purposes of discussing a comprehensive settlement. The Oregon Coalition does not agree to accept the following individual issues outside of the context of a comprehensive settlement.

1. The PacifiCorp Protocol proposal of a Coal Endowment is not supported and should not be adopted. (DPU Issues at 6; Oregon Coalition Issues Paper at 7.)[1, 2]
2. Gadsby, West Valley, Cholla, the APS Agreement, and any new single cycle combustion turbines or peaking contracts, should be classified as Seasonal Resources consistent with the Protocol as filed. (DPU Issues at 6.)
3. Once the APS exchange ends, Cholla will no longer be classified as a Seasonal Resource.
4. The PacifiCorp Protocol proposal for an Oregon opt-out provision for the next coal resource, or any new resource, should not be adopted. (DPU Issues at 7; Oregon Coalition Issues Paper at 7.)
5. There is merit to a situs assignment of QFs. (DPU Issues at 16; Oregon Coalition Issues Paper at 16.) (Also See #6)

[1] "DPU Issues" refers to the "DPU Issues and Alternative Proposals Regarding Docket 02-035-04" filed in UPSC Docket No. 02-035-05 by the Division of Public Utilities on March 5, 2004.
[2] "Oregon Coalition Issues Paper" refers to the "Oregon Coalition Issues Paper and Alternate Proposals" filed in OPUC Docket No. UM 1050 by the Oregon Coalition (Oregon Commission Staff, Industrial Customers of Northwest Utilities, and the Citizens' Utility Board) on February 6, 2004.

Common Positions Continued (Oregon Coalition/Utah DPU)

6. It is reasonable to incorporate a Hydro Endowment in an allocation. The DPU is considering including the Mid C contracts in the Hydro Endowment. (DPU Issues at 15-16; Oregon Coalition Issues Paper at 17-19.)

7. It is reasonable to use a load decrement approach for the treatment of QFs and Hydro Endowment.

8. DSM costs should be assigned state situs. (DPU Issues at 7; Oregon Coalition July 12, 2002, Proposed Issue Resolution Paper at 7.)

9. It is reasonable for PacifiCorp to work with individual states to address issues unique to those states, such as near-term rate impacts.

10. Special Contracts - It seems reasonable to OPUC and DPU that Special contract loads be counted for jurisdictional allocation purposes with adjustments made for values received by the rest of the system. The issue should be further explored with other affected jurisdictions. (DPU Issues at 9-10; Oregon Coalition Issues Paper at 9-10.) Parties are free to raise any issue they believe appropriate regarding the Company's cost recovery associated with special contracts.

11. A Standing Committee should be formed for the purpose of discussing and potentially resolving issues. (DPU Issues at 10.) Any meeting of the Standing Committee should be open to interested persons.

Areas of Discord (Oregon Coalition/Utah DPU)

1. Whether an allocation mechanism that assigns new resources based on incremental load should be implemented by all states during PacifiCorp's next rate case in each state. (DPU Issues at 23; Oregon Coalition Issues Paper at 19-20.)

2. Whether loads of customers choosing direct access will continue to be counted in allocating costs of PacifiCorp's new generating-related costs. A date for which this rule will apply needs to be established. (DPU Issues at 8-9; Oregon Coalition Issues Paper at 20-21.)

3. Whether the value of reserves made available by PacifiCorp's hydro resources should be allocated consistently with the allocation of the Hydro Endowment. (Oregon Coalition Issues Paper at 19.)

4. Whether a Transmission Endowment should be considered. (DPU Issues at 21 & 24.)

5. Assuming load decrements for the Hydro Endowment and QFs, the degree to which wholesale sales for resale should be allocated only to non-decremented loads. (DPU Issues at 24.)

6. Whether Trojan should be assigned to the former Pacific Power & Light states. (DPU Issues at 24.)

7. Whether the fixed costs of baseload (coal) plants should be allocated 50 percent to demand and 50 percent to energy. (DPU Issues at 19.)

8. Whether the fixed costs of combined cycle plants should be classified in excess of 75% demand reflecting greater load following capability of the plant as compared to coal-fired generation. (Oregon Coalition)

9. Whether combined cycle plants should be considered as Seasonal Resources, in part. (Oregon Coalition)

UM 1050 - Revenue Requirement Effects Cost (Benefit) $ Millions
All Comparisons to Roll-In unless otherwise noted

Oregon

		2005-2018 NPV	2005	2008	2011	2014	2018
a	Hybrid (6)	(194)	(42)	(9)	(3)	(27)	(36)
b	Pre-Merger Plant (Modified Accord) (50)	49	(1)	6	9	7	5
c	Hydro Endowment (Modified Accord) (50)	(83)	(10)	(11)	(11)	(11)	(11)
d	Modified Accord (a+b)	(34)	(11)	(5)	(2)	(4)	(6)
e	Protocol Hydro Endowment (9)	442	35	42	63	80	82
f	Protocol Coal Endowment (11)	(423)	(50)	(53)	(55)	(54)	(58)
g	Protocol other factors (e.g. seasonal allocations)	(24)	(1)	(2)	(2)	(6)	(3)
h	Protocol (9/10/11) (e+f+g)	(5)	(16)	(13)	6	20	21
i	Load Decrement HydroTotal (13a-9/10/11)	(132)	(34)	(34)	(11)	9	12
j	Load Decrement Mid-C only (13a-13b)	(114)	(15)	(17)	(16)	(11)	(10)
k	Load Decrement Company Hydro only	(19)	(19)	(17)	5	20	21
l	Trojan assigned to the West (1.2b-13a)	8	1	1	1	1	1
m	QFs assigned situs (1.2c-1.2b)	104	18	17	17	4	4
n	Cholla/APS Treated as Seasonal Resource (32a)	10	1	1	1	1	1
o	Protocol other factors	(5)	(16)	(13)	6	20	21
p	Hydro & QF situs with load decrements (i+m)	(28)	(16)	(18)	6	13	15
q	Dynamic Alternative: Hydro, QF situs w/load decrements Cholla/APS Seasonal (i+m+n+o)	(23)	(31)	(29)	14	34	37
r	Dynamic Alternative compared to Modified Accord	11	(20)	(24)	16	38	43
	Other Issues						
s	Value of Hydro Reserves (61)	(74)	(9)	(9)	(9)	(9)	(9)
t	Sales for Resale Adjustment to Load Decrements (7.5d)(Compared to LD)	105	20	15	12	9	7
u	Value of Hydro Endowment - Average Cost differential	Under review					
v	Transmission Endowment	NA					
w	Tiered Allocations	Workgroup					
x	50/50 Demand-Energy Split (7.5c)(Compared to RI)	(58)	(19)	(21)	3	6	12

Utah

		2005-2018 NPV	2005	2008	2011	2014	2018
y	Hybrid (6)	176	38	7	2	26	37
z	Pre-Merger Plant (Modified Accord) (50)	(76)	1	(9)	(14)	(11)	(8)
aa	Hydro Endowment (Modified Accord) (50)	128	15	16	17	17	18
ab	Modified Accord (p+q)	52	16	7	3	6	10
ac	Protocol Hydro Endowment (9)	(683)	(50)	(64)	(98)	(126)	(132)
ad	Protocol Coal Endowment (11)	652	73	80	85	86	94
ae	Protocol other factors (e.g. seasonal allocations)	34	2	4	3	8	5
af	Protocol (9/10/11) (ac+ad+ae)	3	24	19	(9)	(31)	(32)
ag	Load Decrement HydroTotal (13a-9/10/11)	212	51	53	19	(12)	(15)
ah	Load Decrement Mid-C only (13a-13b)	175	23	27	25	18	16
ai	Load Decrement Company Hydro only	36	29	27	(6)	(29)	(31)
aj	Trojan assigned to the West (1.2b-13a)	(12)	(1)	(2)	(2)	(2)	(2)
ak	QFs assigned situs (1.2c-1.2b)	(78)	(13)	(13)	(13)	(3)	(3)
al	Cholla/APS Treated as Seasonal Resource (32a)	(9)	(1)	(1)	(1)	(1)	(1)
am	Protocol other factors	34	2	4	3	8	5
an	Hydro & QF with load decrement (ag+ak)	133	39	40	6	(15)	(18)
ao	Dynamic Alternative: Hydro, QF situs w/load decrements Cholla/APS Seasonal (ag+ak+an+am)	158	39	43	8	(7)	(13)
ap	Dynamic Alternative compared to Modified Accord	106	23	36	5	(13)	(23)
	Other Issues						
aq	Value of Hydro Reserves (61)	87	11	11	11	11	11
ar	Sales for Resale Adjustment to Load Decrements (7.5d) (Compared to LD)	(156)	(28)	(23)	(18)	(14)	(11)
as	Value of Hydro Endowment - Average Cost differential	Under review					
at	Transmission Endowment	NA					
au	Tiered Allocations	Workgroup					
av	50/50 Demand-Energy Split (7.5c)(Compared to RI)	143	39	41	6	11	18

Tiered Allocation
Issues and Options for Resolution

Initial studies of tiered allocation identified a large number of issues that must be resolved before a tiered allocation method could be put in place. Each issue appears solvable and in most cases more than one solution is possible. This paper summarizes the options identified so far.

1) Overall Design Issues

1.a.) Tier 1 Design

Fundamental to the design of tiered allocations is the identification of loads and resources to be included in Tier 1 over time. The initial design of a tiered allocation method started Tier 1 loads and resources at FY 2002 levels. All growth in resources and loads were added to Tier 2. Over time, a number of Tier 1 resources expire or retire. It is desirable to keep Tier 1 loads and resources relatively in balance because the load/resource balance will affect the assignment of system balancing sales and purchases to Tier 1. The initial concept was to reduce Tier 1 loads to keep them relatively in balance with resources as the later expired or retired over time. This would represent a gradual move toward Rolled-In allocation as Tier 1 loads and resources decline.

Another possible design of a tiered allocation method would replenish Tier 1 resources as they expire. This would keep Tier 1 loads and resources near their initial values. It would also increase the mix of Tier 2 costs in Tier 1. This tiered allocation method requires calculation of Tier 1 and Tier 2 before adjustments, determination of the size of the Tier 1 adjustment, then adjustment of both loads and resources for Tier 1 and Tier 2. Fundamentally, the design of the tiered allocation method will reflect whether parties believe that the tiers should diminish over time or persist.

Option 1: Reduce Tier 1 loads as Tier 1 resources expire. Over time, Tier 1 goes away.

Option 2: Replenish expiring Tier 1 resources, maintaining the size of Tier 1 over time. For issues related to replenishment of resources, see the "Replacement Power" section on page 5 of this paper.

1.b.) Growth Costs

Tiered allocation methods are intended to cause fast growing states would pay for their own load growth. Costs associated with growth can be difficult to quantify and assign to Tier 2 within a single company system. Identifying the addition of new generation resources is easy but each new resource may contribute to factors other than growth. In addition, other system costs needed to support needed to support new resources are more difficult to quantify. Examples include transmission and overheads. A central design question for tiered allocation is whether Tier 2 has adequately captured all costs of load growth.

Option 1: Apply tiered allocation method only to direct new resource costs.
Option 2: Identify additional categories of costs related to growth.
Option 3: Determine the growth-related portion of new resources, existing resources and overheads and assign only growth-related costs to Tier 2.

1.c.) Multiple Tiers
The design of a tiered allocation method could come under considerable pressure if load growth patterns were to change in the future. Utah loads are presently growing faster loads in other states. Present tiered allocation designs place relatively more Utah load in Tier 2 than other state loads. Suppose the growth patterns of Utah and Oregon were to reverse in future years and the Company began acquiring resources in the West. The principles of tiered allocation would suggest that Utah should not be responsible for the costs of those Western resources just because they happened to have grown in prior years. A third tier may be needed to reflect this new era. Indeed, it would be possible to argue that *every* resource is the product of a unique pattern of growth.

Option 1: Agree in advance that no additional tiers will be created.
Option 2: Create additional tiers under specified circumstances.
Option 3: Allocate resources added in each year based on growth formulas specific to that year (i.e. a new tier each year.)

2) Selection of Base Year
The base year divides Tier 1 from Tier 2. Selection of the base year is a fundamental design step for tiered allocation. Since growth and resource acquisition are more-or-less continuous processes, parties may differ in their choice of one base year over another. For initial studies of tiered allocation, FY 2002 was chosen because energy loads and resources were roughly in balance in that year. This base year also places in Tier 2 the newer resources that Oregon parties believed were associated with the type of growth to be captured by Tier 2.

Option 1: Move base year to FY 2005. Moving the base year to 2005 would have the effect of including Gadsby CT's and West Valley in Tier 1. The change would not eliminate the problem of decreasing loads discussed in the Section 4.a. of this paper.
Option 2 Leave base year in FY 2002
Option 3 Pick a different year.

3) Loads To Be Included

3.a.) Wholesale Sales
When wholesale sales contracts expire, existing resources can serve more retail load. The initial tiered allocation studies were based on retail loads. Studies increased the size of Tier 1 loads when existing wholesale sales contracts expired, consistent with the treatment of expiring long-term purchases. Increasing Tier 1 loads in this way contributed to the problem of negative Tier 2 loads in the initial studies. Alternatively, expiring wholesale sales contracts are one way that the Company plans to serve new

retail loads. New resource additions in the Integrated Resource Plan assume that certain wholesale sales contracts will expire. Focusing on these considerations, one could decide not to increase Tier 1 loads as wholesale sales contracts expire.

Option 1	Increase adjusted Tier 1 loads as long-term wholesale sales contracts expire
Option 2	Do not increase adjusted Tier 1 loads as long-term wholesale sales contracts expire.
Option 3	Use loads that include long-term wholesale sales for Tier 1 modeling and allocation factors.

3.b.) Long-Term Wholesale Purchases
The initial tiered allocation studies reduced the size of Tier 1 as long-term purchase contracts expired. The treatment maintains a reasonable match between base period loads and resources. See also Section 1.a. of this paper on "Tier 1 Design."

Option 1	Reduce Tier 1 loads as long-term purchase contracts expire.
Option 2	Do not reduce Tier 1 loads as long-term purchase contracts expire. Replace expiring contracts with an average of Tier 2 resources.
Option 3	Similar to Option 2 but replace expiring contracts with specific replacement resources.

3.c.) Treatment of Load Decrements
The initial tiered allocation studies used decremented loads to allocate West Hydro, Mid-C contracts, and QFs. The studies used no decrements assigned to Tier 2 because new QF contracts were not assumed. The combination of load decrements and tiered allocation is much more computationally complex than either method alone. Load decrements may be redundant with tiered allocation since both are aimed, at least to some degree, at removing load growth impacts. In addition, Utah parties have raised concerns regarding the load decrement approach.

Option 1	Apply the load decrements approach with tiered allocation.
Option 2	Use other methods of calculating a hydro endowment with tiered allocation.

4) Changes in Load Over Time

4.a.) Reductions in Load
State loads can fall as well as rise. The initial design for tiered allocations makes no special provision for that fact. Wyoming loads, in particular, fall below their FY 2002 levels during the forecast. When a state's load falls below the Tier 1 amount, its calculated Tier 2 loads would be negative under the initial design. In effect, the state buys power at Tier 1 costs and sells it at higher Tier 2 costs, creating benefits for that state. Negative loads reverse the signs of many computations and this can make interpretation of results difficult. If a tiered allocation method reduced a state's Tier 1 allocation if loads fall below the base level, parties would have to agree on changes to the

allocation of Tier 1 resources and on whether the state's Tier 1 allocation could increase again once loads started to grow.

Option 1:	Tier 1 load is the lower of the adjusted base period Tier 1 load or the actual load. When actual load is less than adjusted Tier 1 load there would be no Tier 2 allocations. Reductions in Tier 1 load are permanent.
Option 2	Similar to Option 1 except that reductions in Tier 1 load are temporary so that a state could grow again and remain in Tier 1.
Option 3	No adjustment for negative loads in a tier.

4.b.) One state grows then loses load
A state that is growing and loses a material portion of its load, such as could occur in areas that currently serve industrial loads, may create unintended revenue requirement impacts to other states. The design of tiers should consider whether the load being lost is from Tier 1 or Tier 2. The allocation effect of losing loads will be more pronounced in Tier 2 than under Rolled-In because of the smaller base of Tier 2 loads. The loss of load in Tier 2 may magnify any imbalance between Tier 2 retail loads and resources. A key concern in developing tiered allocations is the risk sharing issue.

Option 1	No adjustments for large load losses
Option 2	Adjustment to Tier 1 or Tier 2 depending on when and where load was originally assigned
Option 3	Reset Tier 1 and Tier 2 prices. This option would require specification of when and how the tiers are reset.
Option 4	Add additional tiers

4.c.) Gain or Loss of Service Area
The design of tiered allocations should consider the impact of gaining or losing service territory, either within an existing state or in a new state. Generally, MSP parties have favored treating allocation issues associated with acquisition of service territory as special cases. This discussion focuses on loss of service territory.

Loss of service territory could potentially impact both Tier 1 and Tier 2 loads. A power sales contract may be associated with the loss of service area. This power sales contract would need to be split into Tier 1 and Tier 2 resources.

Option 1	Adjust Tier 1 and Tier 2 loads to reflect the sale, net of obligations under any power sales contract.
Option 2	Treat lost load and power supply obligations in different ways.
Option 3	Do not adjust Tier 1 loads in response to loss of service territory.

4.d.) Sales of Generation
The design of tiered allocations should consider the impact of sold generation. The sold generation resource would be removed from the tier originally assigned and the loads in that tier adjusted. How would the gain on the sale be allocated to the states? If a

purchased contract is secured as part of the sold generation, to what tier should this purchase contract be applied?

Option 1	Remove sold generation from original tier assigned, apply purchase contract & gain on sale to the same tier
Option 2	Remove sold generation from original tier assigned, apply purchase contract & gain on sale to an alternative tier
Option 3	Remove sold generation from original tier assigned, apply purchase contract & gain on sale to both Tier 1 and Tier 2

4.e.) Direct Access

A tiered allocation method should account for load that permanently elects direct access. (Load that elects direct access service with a right to return to cost-based service would continue to be reflected in a jurisdiction's loads and would not be removed from any tier.) One may adopt the view that most permanent direct access load would have been served in the base period and would, therefore, be part of Tier 1. In this view, Tier 1 loads would be reduced by the amount of permanent direct access load. This would have the effect of altering the Tier 1 allocations of other states. Additionally, if the state in which the departing direct access customer was located had a positive Tier 2 allocation at the time of departure, a Tier 2 load adjustment may also be appropriate. Generally, MSP participants have adopted the principle that implementation of direct access should not affect other states. Transition adjustments associated with the direct access load would reflect the change in system cost associated with the loss of this load.

Option 1:	Reduce Tier 1 load by the amount of load that permanently elects direct access service.
Option 2:	Do not reduce Tier 1 load in response to direct access.
Option 3:	Similar to Option 1 but split load reduction between Tier 1 and Tier 2.

5) Resource Issues

5.a.) Replacement Power

In some cases an expiring or retiring resource may be explicitly replaced by another resource. For instance, contracts may be replaced according to specific renewal provisions or a generating resource may be replaced by another built on the same site. Parties have discussed solutions to the Tier 1 design issue discussed in the first section of this paper that give special consideration to costs of replacement resources. When an expiring Tier 1 resource is explicitly replaced by another, the costs of the replacement resource could be assigned to Tier 1. This would slow the decline in the size of Tier 1 compared to the case where no resources are added.

Special treatment of replacement resources would require parties to agree on design choices. For instance, do such replacements include generating plant shut-down, expiring contracts, or both? Do replacements include contracts entered into when the renewal provisions of the expiring contract were vague and the new contract differs from the old? The Integrated Resource Plan does not provide guidance since it does not distinguish between new resources intended to replace expiring resources and resources to meet new growth. Initial studies indicate that the definition and treatment of replacement power has an important effect on the assignment of costs to the tiers.

Option 1: Reduce Tier 1 loads as Tier 1 resources expire. Over time, Tier 1 goes away.
Option 2 Replenish expiring Tier 1 resources with specific identified replacements, where they can be identified.
Option 3 Replenish expiring Tier 1 resources with Tier 2 resources at the average cost of Tier 2 resources.

5.b.) Generation Changes: Overhauls, Re-powering and Capacity Increases
The initial study treated the re-power of Gadsby plant as a Tier 2 resource and not as a replacement of a Tier 1 resource. No special treatment was given to overhauls which increased generating plant capacity. Modeling becomes substantially more complex if the fixed costs of a resource are split between the tiers.

Option 1 Treat overhauls and re-powering as replacements of or changes to Tier 1 resources.
Option 2 Treat generation changes as Tier 2 resources. Split resources where needed. Include the fixed and variable costs associated with overhauls and re-powering in Tier 2.
Option 3 Adjust Tier 1 loads to reflect generation changes.
Option 4 Do not adjust Tier 1 load.

5.c.) Lost Hydro Generation
The initial study treated the lost hydro generation as a reduction to a Tier 1 resource. This issue is similar to the Generation Changes issue discussed in the preceding section of this paper.

5.d.) Planning Reserves
The initial study did not attempt to segregate planning reserves between the tiers. The resources in Tier 2 are built with a reflection of planning reserves, so the output of a base load plant may not be fully dispatched due to fuel and market prices. This is a similar issue where SCCT plants are being added to address peak loads, but they dispatch at low capacity factors.

An alternative view does not recognize that planning reserves are included in or adjusted for in Tier 2 resources.

Option 1 No adjustment for planning reserves in Tier 2
Option 2 Adjust Tier 2 to recognize planning reserves; include a corresponding adjustment in Tier 1.

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PACIFICORP for an Investigation of Interjurisdictional Issues	Docket No. 02-035-04 STIPULATION

Introduction

The parties to this Stipulation are the Utah Division of Public Utilities, the Utah Committee of Consumer Services, the Utah Association of Energy Users Intervention Group, the Salt Lake Community Action Program, the Crossroads Urban Center, the AARP, the Federal Executive Agencies, the Western Resource Advocates (collectively, the Utah Parties) and PacifiCorp (the Company).

On September 29, 2003, PacifiCorp initiated proceedings in Utah, Oregon, Wyoming, and Idaho seeking ratification of an Interjurisdictional Cost Allocation Protocol (Protocol) by the Public Service Commission of Utah (PSCU), the Oregon Public Utility Commission, the Wyoming Public Service Commission and the Idaho Public Utility Commission (collectively, the Commissions). The Company's Protocol filings were docketed as 02-035-04 in Utah, UM 1050 in Oregon, 20000-EI-02-183 in Wyoming, and PAC-E-02-3 in Idaho.[1]

Since the filing of the Protocol, substantial discussions have occurred among interested parties in the context of what has been referred to as the Multi-State Process or MSP. As a result

[1] The Protocol is a method of apportioning the costs and wholesale revenues associated with PacifiCorp's generation, transmission, and distribution systems among the six states in which PacifiCorp operates. If followed by all states, it would, in the long run, result in the opportunity for PacifiCorp to recover 100% of its prudently incurred costs and investments and earn its authorized rate of return. In addition it provides a forum to resolve new interjurisdictional issues should they arise.

of discussions among the MSP parties, the Company has developed a Revised Protocol which is attached as Exhibit A to this Stipulation.

Support of Revised Protocol

The undersigned parties hereby stipulate and agree that they will support the ratification of the Revised Protocol by the PSCU and that they will file and defend testimony supporting the use of the Revised Protocol as appropriate.

Except as otherwise provided below, PacifiCorp agrees, that until such time as the Revised Protocol is amended in accordance with its terms, all general rate case filings made by it in Utah, subsequent to PSCU ratification of the Revised Protocol, will be based upon the provisions of the Revised Protocol. Except as otherwise provided below, the Utah Parties agree that, until such time as the Revised Protocol is amended in accordance with its terms, they will support the use of the Revised Protocol for establishing PacifiCorp's Utah revenue requirement.

Support of the Revised Protocol by the undersigned is contingent upon simultaneous ratification by the PSCU, and continued support thereafter by the undersigned and the PSCU, of the following Rate Mitigation Measures that are intended to apply to calculations of the Company's Utah revenue requirement through March 31, 2014:

1. Calculation of Utah Revenue Requirement.

a. For all Utah general rate proceedings initiated after the effective date of this Stipulation and the Revised Protocol, and until March 31, 2009, the Company's Utah revenue requirement to be used for purposes of setting rates for Utah customers will be the lesser of: (i) the Company's Utah revenue requirement calculated under the Rolled-In Allocation Method multiplied by the Applicable Percentage (i.e., the then-applicable Rate Mitigation Cap) ,specified in Paragraph 2, below; or (ii) the Company's Utah revenue requirement resulting from the Revised Protocol.

b. For purposes of this Stipulation, the Rolled-In Allocation Method shall be the allocation procedures and methodologies used for purposes of interjurisdictional cost allocation in connection with the Company's last Utah general rate case, Docket No. 03-2035-02. Attached as Exhibits B and C are an explanation and an illustration of the Rolled-In Allocation Method. Future additions to Utah's revenue requirement for which there was no unique procedure or precedent under the Rolled-In Allocation Method (such as any situs assignment of costs associated with New QF Contracts, Portfolio Resources and Special Contracts or elements of any future amendments to the Revised Protocol) shall either be excluded from the comparison or used consistently in both allocation methods.

2. Rate Mitigation Caps.

In order to mitigate potential rate impacts on Utah customers, any increase in the Utah revenue requirement as a result of the implementation of the Revised Protocol shall be capped at the Applicable Percentage of the Company's Utah Revenue Requirement calculated under the Rolled-in Allocation Method for the indicated effective periods as follows:

a. 101.50 percent for the period from the effective date of the final PSCU order in the first general rate proceeding filed after the effective date of this Stipulation and the Revised Protocol, to March 31, 2007.

b. 101.25 percent for the period from April 1, 2007 to March 31, 2009.

3. Rate Mitigation Premium.

Subject to the conditions of Paragraph 4b, below, for the period from April 1, 2009 to March 31, 2012, the Company may collect a Rate Mitigation Premium as follows: the

Company's Utah revenue requirement as calculated pursuant to the Revised Protocol multiplied by 100.25 percent.

4. Threshold for Continued Support of the <u>Revised Protocol</u>.

a. If, with respect to the Company's fiscal years 2010 through 2014, the Company's Utah revenue requirement, calculated pursuant to the Revised Protocol, exceeds or is projected by the Company in good faith to exceed 101.00 percent of the amount that would result from using the Rolled-In Allocation Method, the Company may propose a new interjurisdictional cost allocation method. All parties to this Stipulation agree to consider alternative interjurisdictional cost allocation methods in good faith and will use their best reasonable efforts to come to agreement on an amended Revised Protocol within 12 months after the Company proposes a new method.

b. Unless and until any amendments to the Revised Protocol are ratified by the PSCU, for the Company's fiscal years beginning April 1, 2009 through March 31, 2014, for all general rate proceedings, the Company's Utah revenue requirement to be used for purposes of setting rates for Utah customers will be the lesser of: (i) the Company's Utah revenue requirement calculated under the Rolled-In Allocation Method multiplied by 101.00 percent; or (ii) the Company's Utah revenue requirement resulting from the Revised Protocol, plus the Rate Mitigation Premium referenced in Paragraph 3, if applicable.

5. In the event that no final PSCU order has addressed the Company's Utah revenue requirement under the terms of this Stipulation as of the effective date of any adjustment to a Rate Mitigation Cap or Rate Mitigation Premium as specified in paragraphs 2, 3, and 4b above, the Company shall initiate a compliance filing with the PSCU sufficiently in advance of the effective date of any such adjustment, to implement the adjustment. For purposes of this

compliance filing, determination of the Company's Utah Revenue Requirement under both the Revised Protocol and the Rolled-In Allocation Method shall be calculated in conformity with the most recent applicable PSCU order.

6. The Company's semi-annual reports filed with the PSCU, the Utah Division of Public Utilities, and the Utah Committee of Consumer Services shall include calculations of the Company's Utah revenue requirement under both the Revised Protocol and the Rolled-In Allocation Method, and shall include and adequately explain all adjustments, assumptions, work papers and spreadsheet models used by the Company in making such calculations.

7. Neither revenue requirement increases to Utah resulting from the ratification of the Revised Protocol, nor impacts on the Company from Rate Mitigation Measures, will provide a basis, in and of themselves, for the Company to obtain interim rate relief.

8. Nothing herein shall in any way alter or abridge PacifiCorp's right to initiate Utah general rate proceedings when it deems it appropriate to do so.

Reservation of Right to Withdraw Support

In the event any Commission declines to ratify the Revised Protocol, or imposes any additional material conditions on ratification of the Revised Protocol, or in the event any Commission's ratification of the Revised Protocol is rejected or conditioned in whole or in part by any court, or in the event the Rate Mitigation Measures are rejected or materially conditioned by the PSCU or by any court, each signatory to this Stipulation reserves the right, upon written notice to the PSCU and to the other signatories to this Stipulation (at the addresses listed below), served no later than thirty calendar days after receiving notice from the Company of the issuance of the applicable Commission or court order, no longer to be bound by this Stipulation. If any signatory to this Stipulation exercises its right no longer to be bound by the Stipulation, any other signatory may similarly elect no longer to be bound, upon written notice to the PSCU and to the other signatories, served no later than thirty calendar days after receipt of such other signatory's written notice.

Reservation of Rights

The signatories to this Stipulation support the use of the Revised Protocol, in conjunction with the Rate Mitigation Measures, as a solution to MSP issues and agree that ratification of the Revised Protocol and the Rate Mitigation Measures by the PSCU is in the public interest. Each party to this Stipulation agrees to support ratification and implementation of the Revised Protocol and the Rate Mitigation Measures as a whole as specified in this Stipulation, but neither this Stipulation nor the ratification of the Revised Protocol or the Rate Mitigation Measures shall in any manner affect or negate the necessary flexibility of the regulatory process to deal with changed or unforeseen circumstances, and a party's execution of this Stipulation will not bind or be used against that party in the event that unforeseen or changed circumstances cause that party to conclude, in good faith, that the Revised Protocol no longer produces results that are just, reasonable, and in the public interest. Support of the Revised Protocol or the execution of this Stipulation shall not be deemed to constitute an acknowledgement by any party of the validity or invalidity of any particular method, theory, or principle of regulation, cost recovery, cost of service or rate design and, except as expressly provided for herein, no party shall be deemed to have agreed that any particular method, theory or principle of regulation, cost recovery, cost of service or rate design employed in the Revised Protocol is appropriate for resolving other issues.

Signatures

This stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

Dated this _____ day of June, 2004.

PACIFICORP

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Docket No. UE 267
Exhibit PAC/405
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Gregory N. Duvall

Stipulating Parties' Response to PacifiCorp Data Request 20

March 2014

PACIFICORP DATA REQUEST NO. 20 TO STIPULATING PARTIES:

At page 26, lines 8-9 of the Joint Testimony, the Stipulating Parties note that Section X of the 2010 Protocol "traps the cost of the departing load in the state of origin." Please confirm that the "cost of the departing load" that will be trapped in Oregon are transition costs as defined in OAR 860-038-0005(68). If not, please explain. Do the Stipulating Parties agree the transition costs of customers in PGE's five-year opt-out program are effectively "trapped" in the state of origin, in the sense that they cannot be spread to customers in other states?

RESPONSE TO PACFICORP DATA REQUEST NO. 20

In addition to the general objections set forth above, the Stipulating Parties object on the ground that this request calls for a legal conclusion. Notwithstanding this objection, the Stipulating Parties respond as follows:

Yes. The "trapped costs" are transition costs. See the Joint Testimony, page 24, line 10 through page 25, line 13. PGE's program does not suffer from any trapped costs because there are no "fixed generation costs" being assigned to other customers in excess of actual load, which is the case with PacifiCorp.