BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky	)	
Mountain Power for Alternative Cost	)	
Recovery for Major Plant Additions of the	)	DOCKET NO. 10-035-89
Populus to Ben Lomond Transmission Line	)	
and the Dunlap I Wind Project	)	

TESTIMONY

OF

Whitfield A. Russell

on behalf of

The Utah Industrial Energy Consumers

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Whitfield A. Russell. I am a public utility consultant and principal of Whitfield Russell Associates. My office is located at 4232 King Street, Alexandria, VA.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Utah Industrial Energy Consumers ("UIEC").

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Maine at Orono, a Master of Science degree in Electrical Engineering from the University of Maryland, and a Juris Doctorate degree from Georgetown University Law Center. I have been accepted as an expert on bulk power systems in more than 150 proceedings before State and Federal courts, administrative agencies and other tribunals in more than 30 States and in three Canadian provinces. Since I founded Whitfield Russell Associates in 1976, a substantial portion of my consulting work has been related to transmission rates, transmission system planning, and contracts and tariffs related to transmission service and interconnections of loads and generators. A more detailed description of my qualifications is included in Appendix A to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain why the present method for allocating costs of PacifiCorp's transmission system (which allocates 100% of those costs solely to retail consumers in the first instance) should be changed to a method that tracks cost causation and is aligned with PacifiCorp's transmission planning.

I recommend on behalf of the UIEC that the Utah Public Service Commission ("Commission" or "Utah PSC") defer recovery of the revenue requirement from the Energy Gateway Transmission Expansion Project ("Energy Gateway Project") until it can complete a more thorough investigation and until after PacifiCorp makes the Federal Energy Regulatory Commission ("FERC") filings for the Energy Gateway Project. The Commission should condition the amount to be recovered pursuant to Rocky Mountain Power's ("RMP") request upon the outcome of further investigations to determine who the planned cost causers/beneficiaries are. Utah ratepayers should only be responsible for that amount for which they were the planned cost causers/beneficiaries.

If the Commission chooses not to defer rate recovery, then the revenue requirement should be made subject to refund based on the results of further investigations.

Q. WHY ARE YOU RECOMMENDING FURTHER INVESTIGATIONS OF THE ENERGY GATEWAY PROJECT BY THIS COMMISSION?

A. For the foreseeable future, this Commission appears to be the first and last line of defense for Utah retail ratepayers against improper allocation of the costs of new transmission facilities that are being developed in pursuit of expanded wholesale trading and renewable energy projects. Those projects can be expected to benefit primarily ratepayers in, or carry out the public policy choices of, other States.

Until FERC proposed to eliminate an incumbent utility's traditional "right-of-first-refusal" to build new transmission facilities in its recent Notice of Proposed Rulemaking ("NOPR"), FERC had been pursuing Congress' directive to encourage construction of new transmission facilities by incumbent transmission owners, especially new transmission facilities intended to deliver the output of location-constrained renewable resources. *See*

FERC's June 17, 2010, NOPR on *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 131 FERC ¶ 61,253 [hereinafter "NOPR"].

To accomplish this, FERC has been stimulating substantial investor interest in developing transmission assets by approving a number of measures favorable to transmission owners such as: incentive rates of return, favorable capital structures (e.g., 60% equity/40% debt), CWIP in the rate base, assurances of recovery of abandonment costs, encouragement of the development of transmission upgrades for economic benefits even if not needed for maintaining reliability, encouragement of transmission upgrades in advance of the associated renewable project development, rate recovery of deferred tax gross-ups paid by buyers of transmission assets, etc. One of the rationales for these measures is that they will foster competition between generators operating within RTOs and ISOs by reducing transmission constraints and eliminating load pockets.

However, other than California, the electric industry in the Western States is organized in the form of vertically integrated utilities that are not part of an ISO or RTO. Accordingly, there is no neutral, independent party in most Western States, such as an RTO or ISO, charged with continuously controlling and ensuring open transmission access and stakeholder input and supervising transmission planning, transmission access and the operation of organized bulk power markets. As a result, ratepayers in most Western States must rely upon their State regulators for protection against over-ambitious transmission plans or potentially improper allocations of transmission costs. Nor do ratepayers, who are served by vertically integrated utilities and who do not have the benefit of RTO oversight, have any assurance that reducing transmission constraints through construction of massive upgrades will increase competition among wholesale generators. Indeed, PacifiCorp's practice of contracting for nearly all the available long-term firm Point-to-Point transmission capacity on its system seems to undermine competition among wholesale generators.

In summary, given the changed nature and thrust of the regulation of transmission, regulators in many Western States need to step up to protect the retail ratepayer, and I am recommending that this Commission do so.

Q. YOU RECOMMEND LATER INVESTIGATIONS. WHAT SHOULD THIS COMMISSION DO IF ITS LATER INVESTIGATIONS DETERMINE THAT RMP'S ALTERNATIVE COST RECOVERY FOR MAJOR PLANT ADDITIONS ALLOCATES COSTS IN A WAY THAT IS NOT ALIGNED WITH PACIFICORP'S TRANSMISSION PLANNING OR DOES NOT OTHERWISE COMPORT WITH COST-CAUSATION?

A. In that event, the cost allocation RMP has proposed for this and later major plant additions should be altered to align it with PacifiCorp's transmission planning to ensure that costs of those major plant additions are allocated to customers in proportion to the costs those customers cause and/or the benefits they derive from those major plant additions.

Q. WHAT IS YOUR UNDERSTANDING OF THE CURRENT COST RECOVERY METHOD?

A. My understanding is that PacifiCorp allocates 100% of its transmission costs amongst the six retail jurisdictions it serves pursuant to an agreement referred to as the MultiState Protocol ("MSP"). Under the MSP, 41.1304% of the overall system transmission revenue requirement is allocated to Utah retail ratepayers. Utah takes this allotment, which is based on 75% demand (12 coincident peak ("12CP")) and 25% energy, and allocates the costs to its various classes.

The problem with this method is that all transmission costs are allocated to PacifiCorp's retail loads in the first instance. None of the transmission costs are allocated to PacifiCorp's merchant transmission function. Unless changed, this allocation will also apply to the $6.0 billion in costs for the Energy Gateway Project despite the fact that the merchant function appears to be the main driver behind the scale of the Energy Gateway Project.

Then, PacifiCorp credits all revenues received for rendering transmission services to wholesale customers (including transmission charges that PacifiCorp itself incurs in off-system sales) against the transmission costs allocated to retail customers. However, the crediting occurs only if, as, and when those merchant uses are made of PacifiCorp's transmission system.

The harm to Utah retail ratepayers extends beyond that arising from increased transmission costs. By building so much export capability, PacifiCorp actually enhances the ability of retail customers in California to compete with Utah retail customers for the generation that can use the upgraded transmission system, lowering generation costs in California and raising those in Utah (i.e., the transmission upgrades for which Utah retail customers are being asked to pay for disproportionately through misallocations of costs, may actually increase their energy costs as well as their transmission costs). These higher generation rates may not be something Utah retail ratepayers can legitimately complain about, but ratepayers should not be asked to pay for the transmission upgrades that produce that outcome without some offsetting benefit.

Q. HOW IS REVENUE CREDITING RELATED TO COST ALLOCATION?

A. The rate is simply an amount of system cost in the numerator divided by usage in the denominator. In cost allocation, cost responsibility is apportioned to customers in proportion to their test-period usage of the system by reflecting that usage in the denominator of the rate calculation.[1] In revenue crediting, however, one reflects usage by adjusting the revenue requirement in the numerator. This means that when costs of an asset are not allocated to a customer using that asset, the revenues generated by that customer's usage are credited to the overall revenue requirement of the customers to whom the costs are allocated. In other words, with revenue crediting, we reflect a customer's usage by reducing the revenue requirement in the numerator instead of by increasing the billing determinants of usage in the denominator. The overall revenue requirement includes, for example, return, income taxes, depreciation, and operations and maintenance expense associated with the poles, wires, and substations of a transmission system.

Q. HOW ARE TRANSMISSION COSTS ALLOCATED TO WHOLESALE TRANSMISSION CUSTOMERS?

A. In setting wholesale transmission rates, FERC also employs a combination of cost allocation and revenue crediting. However, whereas PacifiCorp allocates 41.1304% of its overall transmission revenue requirement to Utah retail ratepayers, FERC allocates only 22.423% to Utah retail ratepayers. The major reason for the difference is that FERC allocates costs to firm Point-to-Point transmission service whereas Utah does not. Utah provides a credit for the revenue which it attributes to all wholesale transmission service including revenues attributed to firm Point-to-Point transmission service.

[1] Including usage to which the rate is not applied (i.e., in deriving FERC's network rate, costs are allocated to long-term firm Point-to-Point service as well as to Network Service).

Q. PLEASE ELABORATE ON THE FERC APPROACH.

A. In allocating the transmission revenue requirement of a transmission system (the numerator) for purposes of determining the rate applicable to Network Transmission Service (which is also the rate applicable to PacifiCorp in serving retail customers), FERC uses a denominator equal to the sum of peak demands and contract demands to allocate transmission costs in accordance with the following formula:

[Revenue Requirement (“RR”) – Revenue Credits (“RC”) (non-firm and short-term firm)] ÷ [Network Demand (“ND”) (12-CP) + Long-Term Firm Point-to-Point (“LTFPP”) (contract reservations)];

OR:

(RR – RC) / (ND+LTFPP).

As can be seen from the formula, FERC allocates costs to Network Customers (mostly retail loads) based on the average of the 12 monthly coincident peak demands that those customers impose on the transmission system. Because it is an average of 12 monthly peak demands, the 12-CP network load is less than the peak demand imposed by Network Customers at the time of the annual peak.

FERC’s allocation of costs to long-term firm Point-to-Point Customers is based on the amount of contract capacity those customers reserve, irrespective of the amount of transmission capacity they use at the time of the monthly or annual peak demands.

Under FERCs' formula, costs are not allocated to wholesale users who take non-firm transmission service or short-term firm Point-to-Point transmission service. Instead, the revenues generated when a transmission owner provides non-firm and short-term firm transmission service are credited to the revenue requirement in the numerator of the FERC formula. Revenue crediting occurs only if, as, and when those non-firm and short-term firm wholesale uses are made of PacifiCorp's transmission system.

Q. DOES UTAH'S PRESENT COST RECOVERY METHODOLOGY TAKE INTO ACCOUNT REVENUES EARNED BY PACIFICORP IN CONNECTION WITH RENDERING TRANSMISSION SERVICE TO NON-RETAIL CUSTOMERS?

A. Yes, but it appears that revenues are credited for all non-retail uses of PacifiCorp's transmission system and not just for non-firm and short-term firm uses, which are the subject of revenue credits in FERC's network rate. Moreover, it appears that the transmission revenue credit is 20% of the bundled revenue associated with off-system sales of power. Even though FERC allocates costs to long-term firm Point-to-Point transmission service, Utah's cost recovery methodology instead provides a revenue credit if, as, and when wholesale customers (including PacifiCorp affiliates) make long-term firm use of PacifiCorp's transmission system.[2] This means that Utah retail ratepayers bear the risk for non-use of the transmission system, particularly the risk of non-use of costly upgrades to the transmission system, which have been made for the purpose of rendering long-term firm Point-to-Point transmission service.

The fact that Utah uses revenue crediting to account for long-term firm Point-to-Point transmission is very significant. Out of about 15,000 MW of firm use of

[2] Unlike FERC, the Utah Commission does not distinguish between non-firm and short-term firm Point-to-Point transmission service, on the one hand, and long-term firm Point-to-Point transmission service, on the other hand.

PacifiCorp's transmission system, some 5,200 MW of long-term firm Point-to-Point usage has been reserved by PacifiCorp affiliates for transmitting power to wholesale customers, not to retail customers.[3]

Q. WHAT IS WRONG WITH THE EXISTING METHOD UTAH USES FOR ALLOCATING TRANSMISSION COSTS?

A. Retail customers should bear only the costs and risks associated with transmission built to serve them (i.e., if transmission is built in anticipation of retail demand growth that does not occur, that is a risk they should bear). However, retail customers should not bear the risks and costs associated with transmission investments that are made in the hope that wholesale uses will materialize and produce revenues sufficient to offset those costs. Nevertheless, under the current method, retail customers are required to assume the risk that PacifiCorp will generate enough off-system sales to pay the cost of transmission service rendered to those off-system sales customers. Another reason that this is not just and reasonable is that firm Point-to-Point service is accorded the highest service priority, on a par with that provided to Network Customers, and should therefore bear a commensurate allocation of costs. Although it is not yet entirely clear how PacifiCorp determines the amount and timing of transmission revenue it credits to retail customers in

[3] The demand charges called for in the transmission contracts governing 5,200 MW of long-term firm Point-to-Point transmission service that PacifiCorp has reserved for itself amount to approximately $126 million per year. However, PacifiCorp does not use that $126 million fixed annual charge as the basis for its revenue credits on its own 5,200 MW reservation of long-term firm Point-to-Point transmission service. Instead, PacifiCorp derives its transmission revenue credits from 20% of the combined revenues it realizes on its sales of off-system power plus transmission service. Accordingly, even though PacifiCorp's merchant function is contractually committed to pay for the $126 million, that full amount would not be credited if off-system sales revenues plummeted. Fortunately, off-system sales have been substantial enough in recent years that 20% of the combined total has covered the $126 million fixed contract payment for long-term firm Point-to-Point service (a $156 million transmission revenue credit is assumed in the present proceeding). However, there is no assurance that that fortunate circumstance will continue to prevail in the future. As discussed, *infra*, transmission revenue credits derived from 20% of off-system sales will have to increase from $156 million to $922.3 million annually to hold transmission charges constant to retail ratepayers as the Energy Gateway Project is completed.

connection with the Point-to-Point transmission service it renders to wholesale customers (or whether it has the discretion to change that amount and timing), it appears that the revenue credit is based in large part on 20% of its net realization on off-system sales.

What this means is that under the present methodology, cost allocation is not aligned with the transmission planning that gives rise to the costs, and transmission costs are NOT allocated to customers in a manner that tracks cost causation/benefits. Thus, even when transmission improvements are planned and built primarily to serve wholesale customers or facilitate compliance with a single State's renewable portfolio standard ("RPS"), the present method collects 100% of the average transmission system costs (including the above-average costs of that upgrade) from all of PacifiCorp's retail customers. Those retail customers continue to bear 100% of those costs to the extent the anticipated transmission revenues from wholesale customers are delayed, are not fully compensatory, or are otherwise not realized as planned. That is especially true where, as here, PacifiCorp's transmission rates are based on a 1994 historic test period. Also, to the extent a transmission upgrade is designed and built to satisfy public policy concerns of a single State, the costs of that upgrade are not currently allocated solely to ratepayers in the State that instituted the public policy concern and caused the upgrade.

Q. WHAT DO YOU RECOMMEND?

A. I urge the Commission to revisit the faulty logic for transmission cost allocation. We are not suggesting that any additional costs be allocated to any of the other States, but the utility's shareholders, not the retail ratepayers, should bear the risk for unrecovered costs when those costs were expended to benefit PacifiCorp's merchant function. Therefore, the Commission should condition any approval of transmission cost recovery from Utah ratepayers in this proceeding on the results of a later investigation and analysis to determine what percentage of the Energy Gateway Project was planned with Utah ratepayers being the cost causers/beneficiaries.[4]

Because ratepayers in States not served by an RTO or ISO have fewer planning safeguards, States must act to protect their ratepayers. Instead of relying upon revenue credits generated on wholesale transactions to hold transmission costs down, State regulators should allocate applicable and reasonable costs to the retail ratepayers and allocate all additional costs to those wholesale transactions that result from the Energy Gateway Project. This approach is especially important because the States cannot set rates to be charged to non-jurisdictional customers upon which revenue credits are based, and cannot shift transmission costs to generators as urged by Mid-American Energy Company in FERC Docket No. ER10-1791-000. *See* Motion to Intervene and Protest of MidAmerican Energy Company in *Midwest Independent Transmission System Operator, Inc., et al.*, attached as Exhibit ___ (WAR-1). The Commission has even more reason to delay recovery because PacifiCorp's new FERC transmission rate will not be set until sometime after PacifiCorp files its cost allocation proposals, now planned in 2011. For example, Counsel informs me that PacifiCorp's current rates are based on sixteen-year-old data, and, therefore, the Utah Commission will not be able to set revenue credits

[4] Mr. Dennis Peseau filed October 14, 2010, testimony on behalf of Monsanto Company before the Idaho Public Utilities Commission ("Idaho PUC") in Docket No. ID-PAC-E-10-07, which makes many of the same points and recommendations I am making. Attached as Exhibit ___ (WAR-2). Similarly, Mr. Randy Lobb, Utilities Division Administrator of the Idaho PUC, filed testimony that same day on behalf of the Staff of the Idaho PUC. Attached as Exhibit ___ (WAR-3). Mr. Lobb recommends that only 50% of the revenue requirement for the Populus to Terminal transmission facilities be recovered in Idaho retail rates because the remainder is not used and useful and the line cost per mile is twice that for the remaining segments. *See* Lobb T. at 2, 27-29. He recommends accounting for the remaining 50% as plant held for future use. *Id*. at 3. He also testifies that the Energy Gateway Project's projected cost has risen from over $4.0 billion in 2008 to $6.6 billion in 2010, and that the Populus to Terminal segment has escalated in cost from $78 million to $802 million while its capacity has grown from 300 MW at the time of the 2006 MEHC merger commitment to 1400 MW of future capacity. *Id*. at 18, *et seq*.

based on potentially higher wholesale rates that are established later by FERC if the Commission acts to approve recovery now.

Q. DO YOU BELIEVE THE ENERGY GATEWAY PROJECT IS BEING UNDERTAKEN PRIMARILY FOR THE BENEFIT OF RETAIL CUSTOMERS?

A. No. The technical elements of the Energy Gateway Project indicate that it is being undertaken for a number of purposes other than serving retail customers in Utah. Indeed, substantial portions of its costs are being incurred to meet PacifiCorp's long-range plans to connect large blocks of renewable power, planned for development in Wyoming and Montana, to its transmission system, and to export that power, along with surpluses of PacifiCorp's power, to entities other than those served at retail by PacifiCorp (e.g., to wholesale buyers in California, Nevada, Oregon, and Arizona). It is also likely in part caused by the need to comply with Oregon's RPS statute.

Therefore, I urge the Commission to condition its approval on the outcome of a later review of the planning of the Energy Gateway Project and the proposed allocations of its costs between State retail jurisdictions and between retail and wholesale jurisdictions. As FERC has proposed in its recent NOPR on transmission planning and cost allocation, the allocation of transmission system costs should be aligned with the planning of that transmission system.[5] In that NOPR, FERC also proposed that all

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[5] Paragraph 156 of the NOPR states:

> First, we propose to ***more closely align transmission planning and cost allocation processes***. A transmission planning process includes a facility in a transmission plan in order to achieve a specific purpose or purposes . . . . Because such purposes involve the identification of expected beneficiaries—either explicitly or implicitly—***establishing a closer link between transmission planning and cost allocation*** will address in part the Commission's concern that ***existing cost allocation methods may not appropriately account for benefits associated with new transmission facilities***.

(Emphasis added.)

jurisdictional transmission providers develop transmission plans jointly with neighboring systems (*See, e.g.*, NOPR, 131 FERC ¶ 61,253, at ¶ 50), enter into agreements to specify how to develop their joint plans (*Id*. ¶¶ 114, 116–18), and have in place and set forth in their tariffs a method, or set of methods, for allocating the costs of new transmission facilities included in the plan. *Id*. ¶ 159.

Q. WHO BENEFITS FROM SUCH TRANSMISSION UPGRADES?

A. Benefits flow to (1) owners of trapped thermal generators and newly interconnected wind generators; (2) developers and owners of new transmission facilities; (3) the recipients of the renewable power and lower-cost thermal power delivered by the transmission upgrades; (4a) States in which the new transmission facilities are built (more property taxes, temporary employment during construction, and permanent employment from operations and maintenance personnel); and (4b) States in which the new wind generation facilities are built (more property taxes on the power produced, if permitted, temporary employment during construction, and permanent employment from operations and maintenance personnel). However, costs of those transmission upgrades are often allocated to States that do not cause the upgrades and/or do not benefit commensurately from their construction. Indeed, costs are allocated to some States that experience higher costs as their low-cost energy is exported, that are not the site of new wind generation, and/or that are not traversed by the new transmission facilities. This misallocation of costs can be particularly severe with cost allocation methods that socialize transmission costs, such as the well-known postage stamp rates.

Very often, vertically integrated utilities build major Extra High Voltage ("EHV") overlay projects for the purpose of transmitting the output of large concentrations of wind, geothermal or coal-fired energy through and out of their service territories to remote load centers, yet are inclined to allocate costs in the first instance to retail jurisdictions traversed by the power and, only secondarily, to provide retail customers with revenue credits for through-and-out service, but only if, as, when, and to the extent that, such through-and-out service materializes. Such allocations do not comport with the cost causation principle as FERC was reminded in *Illinois Commerce Commission v. FERC*, discussed below.

Q. WHAT EVIDENCE CAN YOU CITE IN SUPPORT OF THE PROPOSITION THAT TECHNICAL ELEMENTS OF THE ENERGY GATEWAY PROJECT INDICATE IT IS BEING UNDERTAKEN FOR A NUMBER OF PURPOSES OTHER THAN SERVING RETAIL CUSTOMERS IN UTAH AND THE OTHER STATES?

A. I have found several items of evidence that support that proposition.

First, the evidence filed by RMP in this proceeding, including, but not limited to, the testimony of Mr. John A. Cupparo, PacifiCorp's Vice President for Transmission, and Mr. Darrell T. Gerrard, PacifiCorp's Vice President for Transmission Planning;

Second, the succession of upgrades planned by PacifiCorp to its existing transmission system referred to as the Energy Gateway Project; and

Third, data taken from PacifiCorp's FERC filings adjusting its network transmission rates.

Q. PLEASE EXPLAIN YOUR THIRD ITEM, DATA TAKEN FROM PACIFICORP'S FERC FILINGS ADJUSTING ITS NETWORK TRANSMISSION RATES.

A. I have summarized data on transmission usage in the spreadsheet attached as Exhibit ___(WAR-4). This data was taken from six of PacifiCorp's transmission filings at FERC that took effect on the indicated dates from April 1, 2006 through August 1, 2010.[6] Those filings indicate that, on average,

a. Network Transmission Service to PacifiCorp retail load in six states represented 54.27% total firm usage of the PacifiCorp transmission system;[7]

b. Network Transmission Service to Utah retail load represented 40.14% of PacifiCorp's system-wide Network Transmission Service;

c. Pursuant to PacifiCorp's response to UIEC 5.11,[8] average deliveries to Utah retail load represent 22.423% of PacifiCorp's total transmission system usage;

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[6] The data in the categories of Network Service (12-CP) and Point-to-Point (contract demand) in PacifiCorp's FERC filings are intended to include all firm usage of the PacifiCorp transmission system that are reflected in the denominator of PacifiCorp's calculation of its Network Transmission rate, consistent with its Open Access Transmission Tariff ("OATT"). Service in the non-firm and short-term firm categories (other than that shown in the attachment for the indicated periods) is accounted for as revenue credits to the numerator of the PacifiCorp Network Service rate. PacifiCorp was asked to confirm the accuracy of this spreadsheet in UIEC's Fifth Set of Data Requests and in its responses, made only minor corrections without indicating the nature of the corrections. Where possible, I have used the corrected results PacifiCorp provided in its responses to the UIEC data requests.

[7] Data taken from PacifiCorp's six FERC filings indicate that total firm usage over the six filings averaged 15,084 MW (100%), of which network service amounted to 9,581.9 MW (63.52%). The six-year average of reservations for long-term firm Point-to-Point service amounted to an additional 5,503 MW (36.48% of the total firm service). The 63.52% of firm service represented by Network Service is further subdivided into tariff Network Service of 8,417.4 MW (55.8%) and non-tariff Network Service of 1,164.5 MW (7.7%). PacifiCorp's retail load represents 97.3% of the tariff Network Service or 54.27% of total firm usage. Network Service to Utah retail ratepayers represents 40.14% of PacifiCorp's tariff Network Service (which in turn represents 55.8% of the total). Accordingly, the FERC filing data indicate that Network Service to Utah retail load represents 22.4% of PacifiCorp's total firm use.

[8] See Exhibit ___ (WAR-5) for copies of all the relevant responses to UIEC data requests.

d. Pursuant to PacifiCorp's response to UIEC 5.1(a), Network Transmission Service represented 63.59% of total firm usage of the PacifiCorp transmission system; and

e. Pursuant to PacifiCorp's response to UIEC 5.1(c), firm Point-to-Point transmission service represented 36.41% of total firm usage of the PacifiCorp transmission system, of which more than 30% is represented by PacifiCorp's own 5,200 MW of long-term firm Point-to-Point transmission service. *See* response to UIEC data request 5.12(a).

Based on this data and the clear intention of PacifiCorp to upgrade its transmission system for the purpose of substantially increasing its ability to make off-system deliveries for sale to entities in Arizona, California, Nevada, and the Pacific Northwest (this does not include retail service but new EHV lines from a new Boardman Hub to three destinations on the Portland General Electric system—Bethel, Round Butte and Boardman Power Plant), I believe it is reasonable to assume that PacifiCorp's retail load will continue to represent approximately 55% of total firm usage of the PacifiCorp transmission system as measured by PacifiCorp in calculating network transmission rates under its OATT. Indeed PacifiCorp's retail load may come to represent significantly less than 55% as time goes on if PacifiCorp's off-system deliveries increase or if more aggressive conservation and demand side management suppress PacifiCorp's network load.

Q. YOU STATED THAT UTAH RETAIL LOAD REPRESENTED 22.423% OF THE LONG-TERM FIRM USAGE OF THE PACIFICORP TRANSMISSION SYSTEM UNDER ITS FERC OATT. HOW MUCH OF PACIFICORP'S

TRANSMISSION RATE BASE IS ALLOCATED TO UTAH RETAIL LOADS UNDER THE MSP ALLOCATION SYSTEM?

A. 41.1304%. This is much more than the 22.423% allocated to Utah retail network service in PacifiCorp's FERC filings. This 41.1304% is the value given to the SG allocator for Utah as indicated on page 4.1 of the exhibits to the testimony of Mr. Brian S. Dickman, manager of revenue requirements for the Company. The SG allocator is used for allocating Transmission Plant. *See* page 9 of Appendix B (Allocation Factor Applied to each Component of Revenue Requirement) and pages 2-3 of Appendix C (Allocation Factors, Algebraic Derivation) of the 2010 Protocol filed with the Utah PSC by RMP on September 15, 2010, in Docket No. 02-035-04.

Q. HAS PACIFICORP OFFERED A RATIONALE FOR ALLOCATING 41.1304% OF ITS TRANSMISSION REVENUE REQUIREMENT TO UTAH RETAIL CUSTOMERS WHEN THOSE CUSTOMERS REPRESENT ONLY 22.423% OF ITS FIRM LOAD?

A. Yes, but not in its filing or testimony in this case. The rationale was provided in response to subpart (b) of UIEC Data Request 5.12. That request and the response are as follows (emphasis added):

UIEC Data Request 5.12: Please state whether it is reasonable to assume that PacifiCorp retail load will continue to represent approximately 55.8% of total firm usage of the PacifiCorp transmission system as measured by PacifiCorp in calculating network transmission rates under its OATT.

(a) If not, please state what percentage of the total firm usage of the PacifiCorp transmission system is projected to be represented by PacifiCorp's retail load.

(b) If so, please explain how PacifiCorp's allocation to its retail loads of 100% of the revenue requirement associated with its existing and proposed network transmission facilities (subject to revenue credits) can be said to be consistent with:

(i) The 55.8% usage of the PacifiCorp transmission system attributed to those retail customers in its FERC OATT filings.

(ii) The benefits that retail customers derive from the PacifiCorp transmission system.

Response to UIEC Data Request 5.12

a) It is not. In addition to network service, over 5,200 MW of firm point-to-point service is held by PacifiCorp Energy and primarily used to serve load and to make off-system sales which maximize the sale of PacifiCorp's available generation resources to the benefit of retail customers. The point to point service contracts represent over 30% of the firm system usage of the PacifiCorp transmission system. ***Any allocation of transmission system costs to retail load should include the portion represented by point to point firm contracts.*** Adding this amount of firm service to PacifiCorp's retail load obligation increases the percentage to in excess of 85%.

b) Allocation to retail loads of 100% of the revenue requirement associated with existing and proposed network transmission facilities (subject to revenue credits) is expected to produce a result consistent with the FERC OATT filing when reconciling items are taken into account.

Q. DO YOU AGREE WITH PACIFICORP'S RATIONALE?

A. No.

Q. WHAT'S WRONG WITH PACIFICORP'S RATIONALE AND APPROACH?

A. PacifiCorp's rationale and approach are wrong on several counts, including the following:

1. Under the MSP, retail ratepayers bear the transmission costs associated with both PacifiCorp's network transmission service (which is used by retail customers) and the transmission costs associated with its off-system sales by use of firm Point-to-Point transmission service (capacity which is not used by retail customers). The 5,200 MW of firm Point-to-Pont transmission service is held by PacifiCorp Energy for the purpose of rendering firm transmission service to customers of other systems, not to the retail customers of PacifiCorp. Therefore, the associated costs should not, in the first instance, be allocated to PacifiCorp's retail customers based on a hope that its 5,200 MW of firm Point-to-Pont transmission service will be used by PacifiCorp Energy to serve wholesale customers and generate revenue credits for retail customers. Retail customers are being required to bear the risk if such off-system sales do not materialize or are not fully compensatory if they do materialize, as well as the risk for the understatement of revenues that results from not having more current transmission rates.

2. PacifiCorp appears to be obligated, at least in concept, for enough firm transmission service to serve about 15,200[9] MW of peak demand.[10] But PacifiCorp's peak demand is only about 10,000 MW (of which 9,433.1 MW represented the coincident peak demand of its control area on July 27, 2009). Its generating resources have a peak capability of 12,131 MW (Cupparo at 3:67).

3. PacifiCorp has obligated its retail customers to pay for about 50% more firm transmission capacity than is needed to meet its peak demand and about 25% more than its peak generating capability. These facts indicate that its transmission system already may have sufficient firm capacity to meet substantial growth in retail load. Accordingly, it is not clear whether PacifiCorp could simply terminate its contracts for firm Point-to-Point transmission service in stages and divert the

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[9] This 15,200 MW obligation is the combined total of 5,200 MW of peak demand servable from firm Point-to-Point service held by PacifiCorp Energy and about 10,000 MW of Network Transmission Services. Much of the Network Integration Transmission Service held by PacifiCorp Energy is used to facilitate its retail load service, which represents 55.29% total firm usage of the PacifiCorp transmission system. *See* response to UIEC 5.1(b). Firm Point-to-Point transmission service represents 36.410% of total firm usage of the PacifiCorp transmission system of which about 30% is held by PacifiCorp Energy. *See* responses to UIEC 5.1(c) and 5.12(a).

[10] By its very nature, the 5,200 MW of firm Point-to-Pont transmission service held by PacifiCorp Energy entitles it to make 5,200 MW of through and out deliveries (off-system sales) at the same time PacifiCorp is serving its retail network load. It appears that PacifiCorp's retail load reaches a peak demand of about 10,000 MW (projected to reach 10,340 MW in 2011), by means of Network Integration Transmission Service. *See* responses to UIEC 5.1(b); October 5, 2010, handouts in PacifiCorp's IRP Meeting provided in Exhibit ___ (WAR-6). The response to UIEC No. 10.2 states:

> PacifiCorp Commercial and Trading is the name of a wholesale transmission customer with whom PacifiCorp Transmission has contracted for point-to-point agreements. Commercial and Trading is the name of the marketing function division within PacifiCorp Energy.

Both PacifiCorp's Open Access Same-time Information System, a bulletin board called OASIS, and its Point-to-Point transmission contracts covering about 5,200 MW of contract demand indicate that the PacifiCorp Merchant Function, a.k.a. Commercial & Trading Group, is the Customer under the Point-to-Point contracts. The Transmission Owner under the Point-to-Point Contracts (and as listed on the OASIS) is PacifiCorp. Pacific Energy owns PacifiCorp and PacifiCorp Merchant Function, a.k.a. Commercial & Trading Group. Response to UIEC No. 5.12 states that PacifiCorp Energy holds 5,200 MW of Point-to-Point contract rights, which it apparently does through PacifiCorp Merchant Function, a.k.a. Commercial & Trading Group.

freed-up transmission capacity as needed to provide service to retail network loads instead of expanding its transmission system.[11]

4. PacifiCorp represents that its retail customers receive a revenue credit for revenues related to use of its transmission system for serving loads of others, but the revenue credit may not reflect service being rendered at a fully compensatory rate for several reasons, including:

a. PacifiCorp Energy (like all transmission providers) is permitted to provide transmission service at a discount off the fully compensatory rate set forth in its OATT. Under the current methodology, retail ratepayers will absorb the cost of under-recovery on such discounts.

b. If PacifiCorp Energy delivers energy to an off-system buyer by means of its 5,200 MW of firm Point-to-Pont transmission service, it appears that the transmission revenue credit is equated to 20% of the amount PacifiCorp realizes on that off-system sale (e.g., non-fuel energy sales revenue) and not what PacifiCorp charges its affiliate for long-term firm Point-to-Point transmission service. Because transmission rate base is projected to increase four-fold in response to development of the Energy Gateway Project, a transmission revenue credit based on 20% of the amount PacifiCorp realizes on off-system sales may well not recover the full cost associated with rendering long-term firm Point-to-Point transmission service in the future.

[11] I realize that during on-peak periods, there may not necessarily be a one-to-one correlation between a system's ability to serve a one megawatt increase in retail network load and its cancellation of one megawatt of off-system sales. However, that is the assumption underlying FERC's allocation of transmission costs.

c. The revenue PacifiCorp realizes from rendering non-firm and short-term firm Point-to-Point transmission service is credited to the numerator of the FERC network rate calculation, but that revenue credit is reset only when Utah sets retail rates or when PacifiCorp files an update of its FERC network rate. *See* responses to UIEC 5.4, 5.5, 5.7, 5.8. If revenues from those categories of transmission service increase, retail ratepayers do not receive a credit for the incremental revenue. Those revenues are instead retained by PacifiCorp's shareholders.

5. These facts also raise substantial questions about whether PacifiCorp is hoarding firm transmission capacity to leverage its 100% control over the transmission market and thereby increase its market power in wholesale generation markets and/or engage in other abuses of its market power (e.g., using its right-of-first-refusal to build transmission facilities within its service areas in order to forestall developments of new transmission facilities by competing independent transmission companies).[12] By hoarding firm transmission capacity, PacifiCorp gains the ability to interject itself between buyers in a high-cost region (e.g., in California) and sellers in a low-cost region (e.g., in the Pacific Northwest), refuse to transmit power and insist instead on a buy-sell arrangement in which PacifiCorp buys low and sells high. By doing so, PacifiCorp can capture a disproportionately large share of the savings that would otherwise be split between the buyer and the seller (after the buyer and seller paid PacifiCorp the often small cost of transmission service). If the proportion of the savings seized

[12] See the testimony of Mr. Dennis Peseau before the Idaho PSC on behalf of Monsanto Company, cited above, summarizing competing transmission projects under development in the vicinity of the PacifiCorp transmission system at pages 14 *et seq.*, and his Exhibit 226 (DEP-6).

> in this way exceeds the charge PacifiCorp would realize by transmitting, it comes out ahead, if not, the retail ratepayers pick up the difference.
>
> Allowing PacifiCorp to allocate the risks and costs of excess firm transmission capacity to retail customers and to contract with itself for that excess capacity as firm Point-to-Point service encourages overbuilding of transmission facilities and gives PacifiCorp Energy an unfair advantage in competing with other wholesale suppliers for wholesale sales.

Q. YOU NOTE THAT FIRM POINT-TO-POINT TRANSMISSION SERVICE REPRESENTS 36.41% OF TOTAL FIRM USAGE OF THE PACIFICORP TRANSMISSION SYSTEM AND THAT NETWORK TRANSMISSION SERVICE REPRESENTS 63.59% OF TOTAL FIRM USAGE OF THE PACIFICORP TRANSMISSION SYSTEM. PLEASE EXPLAIN.

A. As noted previously, long-term firm Point-to-Point transmission service and Network Transmission Service represent the two categories of long-term firm transmission service to which costs are allocated by FERC. *See* response to UIEC Data Request 5.9. Retail loads are typically included as part of the firm Network Transmission Service, whereas other utilities are typically the customers of power delivered under long-term firm Point-to-Point transmission service. FERC requires a utility's transmission revenue requirement to be allocated to both of these firm services irrespective of whether such services are compensatory.

FERC's approach is grounded in the notion that a utility builds its transmission system primarily to serve firm retail customers and may offer other long-term firm service to other utilities, customers or generators. FERC requires those other firm services to be provided on an equal basis with network service (e.g., subject to the same curtailment priority) even if those other firm transmission services are offered at a discount rate (to generate revenue for a few years) or because a lower rate is carried-over under grandfathered contracts. Revenues from other uses (e.g., non-firm and short-term firm transmission), because they are volatile, episodic or are offered on a non-firm basis, are the subject of revenue credits under FERC's approach.[13]

However, in allocating transmission costs to retail ratepayers, States are free to use rates of return and cost allocation methodologies different from those used by FERC and are not bound by the FERC formula. Currently, Utah's approach is different from FERC's in that retail customers bear the burden of under-recovery on firm Point-to-Point service. Because they are governed by FERC's methodology, other network customers (e.g., transmission dependent wholesale customers) do not share that burden. Furthermore, when based on a significantly outdated transmission rate, the amount guaranteed by the States is subject to an even greater risk.

Q. HOW DO PACIFICORP'S PLANNING AND OPERATIONS DIFFER FROM THE NOTION UNDERLYING FERC ALLOCATIONS OF TRANSMISSION COSTS?

A. The major transmission upgrades PacifiCorp is planning with the Energy Gateway Project do not appear to be caused by growth in retail load nor are they intended primarily for the benefit of retail load. Instead, they appear to be an EHV overlay developed in large part, if not primarily, for maintaining and increasing exports and through-and-out transactions.

[13] This volatility is reflected in the drop of PacifiCorp's off-system sales from $860,950,758 in 2008 to $643,321,157 in 2009. *See* PacifiCorp's 2009 FERC Form 1 (filed in April 2010) at 300:11 (447) Sales for Resale. Retail sales increased from 2008 to 2009. *See id*. 300:10, TOTAL Sales to Ultimate Consumers.

Q. COULD YOU NOW PLEASE DISCUSS YOUR FIRST ITEM THAT INDICATES THE ENERGY GATEWAY PROJECT IS NOT PRIMARILY CAUSED BY, OR FOR THE BENEFIT OF, RETAIL RATEPAYERS: THE TESTIMONY OF PACIFICORP.

A. Mr. Cupparo notes (at 8:155-156) that "The Energy Gateway plan is comprised of eight interrelated and interdependent transmission segments . . . . [that] will be spread among six states, numerous communities and counties, and significant areas of federally-administered lands and will add approximately 2,000 miles of new transmission lines to PacifiCorp's transmission system."

In engineering terms, the $6.0 billion expenditure on the Energy Gateway Project is disproportionate to the needs of retail customers. It represents a quadrupling of PacifiCorp's present $2.1 billion transmission rate base (Cupparo at 3:63) and is projected to add about 9,000 MW of export capacity by 2018 to a system with a system peak generating capability of approximately 12,131 MW.[14] (Cupparo at 3:67). This planned quadrupling of transmission rate base should be contrasted with the much lower growth in PacifiCorp's Utah retail network load which is projected to grow about 19% from 2010 through 2018 when PacifiCorp projects that it will complete most of the Energy Gateway Project, about 2.2% per year through 2020. *See* slide 25 of PacifiCorp's October 5, 2010, presentation of the 2011 IRP Public Input Meeting.

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[14] The addition of 9,000 MW of export capacity is an estimate based on an assumption that six new 500 kV interconnections will be added to adjoining systems with a nominal rating of 1,500 MW each. This is a very large increase in export capacity even after taking into account the possibility that PacifiCorp can demonstrate that some of the increased interconnection capacity can be attributed to a need to accommodate NERC reliability criteria and the intermittent nature of wind generation, and to maintain angular and voltage stability. These possibilities, and their effect on costs properly allocable to retail ratepayers, can be developed in the later investigation UIEC recommends be undertaken by the Utah Commission.

Q. HAVE YOU MADE ANY CALCULATIONS OF THE POTENTIAL IMPACT OF THE ENERGY GATEWAY PROJECT UPON FUTURE RETAIL RATES?

A. Yes. Attached as Exhibit ___ (WAR-7) is a spreadsheet showing the impact upon retail rates of adding the entire $6.0 billion cost of the Energy Gateway Project to PacifiCorp's transmission rate base but holding revenue credits derived from off-system sales and other transactions at present levels. From this it can be seen that revenue credits from off-system sales would have to increase from the present level of $156.3 million to $922.3 million per year in order to hold transmission rates constant. If those revenue credits remain at present levels, the transmission component of retail rates will increase by 181% of present levels to 281% of the present transmission component. In other words, off-system sales would have to increase from $763.5 million to $4.51 billion to maintain the transmission component of retail rates at its present level (assuming that 20% of off-system sales revenues are deemed to be a recovery of transmission costs and continue to be accounted for as transmission revenue credits). When asked in Data Request UIEC 10.4(b) for the amount of transmission contract capacity it would add in the next five years, PacifiCorp responded: "Unknown. PacifiCorp cannot predict future customer requests for service or willingness to accept contract offers."

Q. WHAT OTHER TESTIMONY FILED IN THIS PROCEEDING INDICATES THAT THE ENERGY GATEWAY PROJECT IS NOT PRIMARILY FOR THE BENEFIT OF RETAIL RATEPAYERS?

A. At 11:229-231, Mr. Cupparo states "This case includes approximately $548 million of capital investment (total Company) for the Populus to Ben Lomond section of the

Populus to Terminal transmission line segment." At 10:206-211 he states that the two sections of transmission line at issue in this proceeding:

> . . . increase transfer capability from north to south and south to north across the Company's transmission system. By doing so, the Company addresses a key constraint (Path C), meets an MEHC [MidAmerican Energy Holding Company], transmission commitment and improves the Company's ability to import and export lower cost resources depending upon seasonal needs and operating conditions.[15]

Clearly, improving the Company's ability to provide increased transmission capacity for exporting both its own surplus power and the output of projects owned by others is not necessary to serving retail customers. Revenues attributed to transmission of off-system sales and pass-through transactions lessen charges to retail customers through revenue credits, but, as Energy Gateway Project quadruples PacifiCorp's investment in transmission, retail ratepayers bear the risk that off-system sales will not grow commensurately.

A substantial deficiency in transmission cost recovery through off-system deliveries can be expected to appear and grow larger if measured against incremental transmission costs (i.e., if PacifiCorp builds new, higher-cost transmission facilities specifically to increase its firm off-system deliveries and those deliveries do not materialize).

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[15] The Populus-Terminal line segment is located north of the Utah load center in Salt Lake City ("SLC"). As of two years ago (as indicated in WECC's 1-1-09 operating map), ***two*** 345kV-lines and one 230kV-line entered Terminal from the north. The upgrade known as Populus-Terminal adds two more 345kV-lines. Terminal is about one mile SSW of the SLC airport and a few miles west of the State capitol. As of two years ago, there were ***six*** 345kV-lines entering Camp Williams from the south, four originating from Mona and two from Huntington Canyon and Hunter/Emery which are major coal-fired power plants owned by PacifiCorp. The SLC load center is located between the Terminal and Camp Williams substations. Also as of January 1, 2009, the Terminal lines plus one 345kV-line to south central Idaho and two 230kV-lines to Naughton (coal-fired) in SW Wyoming emanated from Ben Lomond (10 miles NNW of Ogden).

Q. IS THERE ADDITIONAL TESTIMONY INDICATING THAT THE ENERGY GATEWAY PROJECT IS NOT PRIMARILY CAUSED BY, OR FOR THE BENEFIT OF, RETAIL RATEPAYERS?

A. Yes. Further testimonial evidence was summarized in UIEC's September 16, 2010, Reply In Support of UIEC's Motion To Defer Recovery of The Major Plant Addition Costs. That pleading refers to portions of the testimony of RMP's witnesses Cupparo and Gerrard that support the proposition that the Energy Gateway Project is neither solely nor even primarily caused by, or for the benefit of, retail ratepayers (at pages 10 *et seq.*). *See* Cupparo 9:174-77, 9:178-79, 9:191-92, 10:194-97; Gerrard 3-4.

Q. PLEASE DISCUSS YOUR SECOND ITEM OF EVIDENCE INDICATING THAT PACIFICORP IS EXPANDING ITS SYSTEM FOR REASONS UNRELATED TO RETAIL SALES: THE SUCCESSION OF PLANNED UPGRADES REFERRED TO AS THE ENERGY GATEWAY PROJECT.

A. These planned upgrades are the subject of the 29-page attachment to PacifiCorp's response to UIEC's data request 1.59 which I have attached as Exhibit ___(WAR-8). Subpart (c) of that response states:

> Conceptual planning materials and draft documents were developed and reviewed internally, handouts were prepared or circulated at the meetings. The discussions centered around developing planning base case details, specifically loads, long term growth, future generation sites, system reliability and constructability, operational requirements, assumptions under various system outage contingencies. Please refer to Attachment UIEC 1.59 for supporting documentation.

Subpart (a) of PacifiCorp's response to UIEC's data request 1.59 states:

> Various personnel from PacifiCorp's transmission planning group and management of Rocky Mountain Power and Pacific Power were engaged in internal planning for the Gateway project, including its segments. The project was conceived in response to PacifiCorp's Integrated Resource Planning (IRP) requirements and in response to load and resource reviews. The project was also developed in response to questions and inquires from federal state and local government and regulatory agencies requesting future planning information regarding the Company's long range transmission needs. The persons involved in such internal planning efforts include a number of staff personnel from Transmission Planning, Grid Operations, Field Operations, Finance and Executive Offices. Meetings were held at various PacifiCorp's offices in both Portland, Oregon and Salt Lake City, Utah.

Q. PLEASE SUMMARIZE THE INFORMATION PROVIDED IN THE ATTACHMENT REFERENCED IN RESPONSE TO UIEC 1.59.

A. The 29-page attachment includes one-line diagrams for 2007, 2010, 2011, 2012, 2013, 2017, 2018 and "2018 Ultimate Transmission System." With one exception, all of these diagrams are dated at least three to four years ago.[16] As one would expect from plans being developed over the last three to four years, the one-line diagrams reflect inconsistent transmission plans considered, many of which have apparently been rejected.

[16] The only recent diagram, dated 9/17/2010 (page 10, "Wasatch Front Master Plan"), seems incompatible with the older diagrams representing the 2007 system, as expanded into the "2018 Ultimate Transmission System" one-line diagrams (page 18), and with the diagram shown on the untitled page 29, which appears to match page 20, but nothing else. The diagram dated 9/17/2010 (page 10 of 29) is the only diagram that is not three to four years old. It is inconsistent with what was presented less than 3 weeks later on October 5, 2010, in the Company's IRP presentations, indicating at the very least that PacifiCorp's plans for the Energy Gateway Project remain in flux.

Q. WHAT DO YOU DEDUCE FROM THIS SEQUENCE OF PLANS?

A. The diagrams dealing with Wasatch Front options call for far fewer upgrades in the 345kV north-south corridor in Utah from Ben Lomond-Terminal-Camp Williams-Mona, indicating that considerable through-flow unrelated to Utah retail loads is under consideration.

The two new 500kV-lines shown between INTL and Mona appear intended to provide for maintaining N-1 reliability in order to protect the underlying 345kV system serving retail loads in Salt Lake City from overloading as a result of through-flows making their way down onto the underlying 345 kV network during major single contingency 500kV-line outages. Again, this concept clearly represents a "through" transmission arrangement bypassing Salt Lake City to provide firm service from off-system resources to off-system loads.

Additional evidence of PacifiCorp's intent to serve off-system loads with the Energy Gateway Project is provided on the one-line diagram at page 26 of 29. It shows proposed upgrades west of the Melba 500 kV substation (which is the westernmost point of the PacifiCorp network depicted on the one-line diagrams). That one-line diagram depicts a new substation called Boardman Hub, planned as the terminus of nine new 500 kV-lines:

1. Two 500 kV-lines from PacifiCorp's planned Melba substation (PacifiCorp's October 5, 2010 presentation changed Melba to Hemingway);
2. Two 500 kV-lines from Canada;
3. Two 500 kV-lines to California;

4. One 500 kV-line to Portland GE's Bethel Substation;
5. One 500 kV-line to Portland GE's Boardman coal plant; and
6. One 500 kV-line to Bonneville's McNary plant looping into the Coyote Springs plant of Avista/Portland GE.

The planned Boardman Hub thus provides a new location at which PacifiCorp can combine imports from Melba with those from Canada and Bonneville for delivery to loads in California, western Oregon and other parts of the Pacific Northwest.

Q. WHAT ELSE DO YOU DEDUCE FROM THE SEQUENCE OF DIAGRAMS PROVIDED IN THE ATTACHMENT REFERENCED IN THE UIEC 1.59 RESPONSE?

A. What seems clear from these diagrams is that most of PacifiCorp's $6.0 billion transmission upgrade is being undertaken for the purpose of increasing PacifiCorp's export capacity by approximately 9,000 MW for delivery of wind generation and other resources to off-system destinations in California, Nevada, Arizona, and Oregon This purpose is strikingly evident in the plans for transmission lines that pass through, or bypass altogether, the Salt Lake City area.[17] Thus, it appears that very little of the planned $6.0 billion expenditure on upgrades is being undertaken for the purpose of delivering power to PacifiCorp retail loads. Nevertheless, unless the methodology for transmission allocation is changed, 100% of the annual revenue requirement associated

[17] It is probable that part of the large thermal capability of the planned interconnections is intended to reduce impedance and transmission losses (i.e., large conductors are selected for the purpose of controlling transmission losses) and to maintain stability in the face of the vastly increased cross-system flows planned by PacifiCorp. That is, the potential for instability is likely limiting line loadings to well less than the thermal rating of the interconnections.

with the $6.0 billion upgrade will be allocated to retail customers in the first instance (subject to a revenue credit for off-system deliveries). This outcome is at odds with the cost-causation principle that binds FERC.[18]

Q. YOU REFERRED TO PACIFICORP'S INTENT TO USE THE UPGRADES IN THE LONG-TERM PLAN FOR SERVING OFF-SYSTEM CUSTOMERS FOR RENEWABLE POWER. PLEASE EXPLAIN.

A. This intent is reflected in the six new 500 kV-lines (each thermally rated to carry about 1,500 MW for a total of 9,000 MW of capacity) that would connect directly or indirectly to California by 2018:

1. Two 500 kV-lines south from the new Boardman Hub.[19] These lines are also interconnected from Boardman Hub to:

    (a) two new 500 kV-lines north to Canada,

    (b) two new 500 kV-lines to Idaho/Wyoming through Melba SS – the line segments for which most PacifiCorp upgrades are planned,

    (c) one new 500 kV-line to PGE's Boardman Plant, and

    (d) one new 500 kV-line to PGE's Bethel SS with a tap to PacifiCorp's Round Butte SS;

[18] FERC was recently reminded of its obligation to adhere to the cost-causation principle in a remand from the Seventh Circuit Court of Appeals. *See Illinois Commerce Commission v. FERC,* 576 F.3d 470, 476 (7th Cir. 2009) ("*ICC v. FERC*") (holding that the Commission "is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members"). Since *ICC v. FERC* was decided, FERC issued its NOPR in which it announced, among other things, its intention to align the allocation of transmission costs with the transmission planning process that gives rise to those costs.

[19] Boardman Hub is planned to be located northeast of the California-Oregon Border ("COB")/Malin.

2. Two 500 kV-lines heading west from Limber/INTL and Mona to north-central Nevada (clearly for delivering power destined for California because the load in northern Nevada is probably too small to absorb 3,000 MW of additional wind generation);
3. One 500 kV-line south from Mona to Four Corners or Navajo (Both of which connect to Arizona, southern Nevada, and southern California);
4. One 500 kV-line heading southwest from Mona to Crystal – on the way to Las Vegas, Nevada and southern California.

Q. DO THESE ATTACHMENTS TO PACIFICORP'S RESPONSE TO UIEC 1.59 TELL US ANYTHING ABOUT THE LOADS AND GENERATION TO BE CONNECTED TO THE ENERGY GATEWAY PROJECT?

A. Yes. The page labeled "Future Wyoming Grid Transmission Plan," (page 21 of 29) dated May 29, 2007, indicates that 1,098 MW of loads and 3,910 MW of generating resources will be connected to the upgrade.[20]

Q. IN SUMMARY, WHAT PROBLEMS SHOULD THE FUTURE INVESTIGATIONS YOU ARE RECOMMENDING TO THE COMMISSION ADDRESS?

A. The Commission's future investigations should address the recurring issue of how to allocate costs of major transmission additions in accordance with cost causation, an issue

[20] There is no indication in these materials of the season or time-of-day during which these increments of load growth and resources are likely to occur. Nor is such information provided for existing loads. The "net" of new and existing loads and resources could easily far exceed the difference between 1,098 MW new load and 3,910 MW new generation. Note that 2,000 MW of installed capacity is indicated for "Clipper," which represents about half of the 3,910 MW total, and that Clipper's capability is six times bigger than that for any other project. Clearly, these data need verification and updating.

raised by the Energy Gateway Project. This issue is one result of FERC's grant of very substantial economic incentives to transmission owners to upgrade transmission facilities to relieve congestion, increase wholesale competition, and integrate vast amounts of renewable resources into the nation's grid. Instead of building transmission facilities to cure or avoid violations of reliability criteria, transmission owners are encouraged to develop EHV transmission upgrades in advance of when they are needed and that exceed those required to maintain reliability criteria. These upgrades overlay the pre-existing grid to transmit largely non-firm or intermittent power to achieve economic benefits or to achieve public policy goals.[21] What should be considered is planning that differentiates a grid to serve retail customers from one that serves both that purpose and the greater goals envisioned by FERC. That is, there really should be two transmission expansion plans:

1. One plan that accommodates just retail customers (and perhaps a few traditionally transmission dependent wholesale customers) and serves them with credible generation plans; and

2. A second plan that builds on the first in order to accomplish other purposes.

Q. WHAT ELSE DO YOU RECOMMEND?

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[21] Whereas reliability is assessed by very specific deterministic or probabilistic criteria developed and accepted over a period of many decades, assessment of social policy goals and economic benefits is a relatively new practice in the electric industry that is susceptible to more elastic criteria and exaggeration. In *ICC v. FERC*, the Seventh Circuit Court of Appeals recently reminded FERC that it must allocate costs to customers in a manner roughly commensurate with the costs they cause or the benefits they derive. Accordingly, there is no getting around the need to assess benefits. Nevertheless, FERC's new NOPR recognizes the difficulty of assessing economic benefits of transmission upgrades. At paragraph 135 of the NOPR, FERC states that "there is no consensus on what types of benefits should be considered or how such benefits should be calculated." Some want to consider "environmental impacts, land conservation and energy security." At paragraph 158, FERC states:

> The Commission recognizes that identifying which types of benefits are relevant for cost allocation purposes, which entities are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. The Commission believes that a transparent transmission planning process is the appropriate forum to address those issues.

A. I recommend focusing the analysis on cost allocation issues that the Utah Commission can address. In particular, I urge the Utah Commission to examine whether PacifiCorp's proposed allocation of transmission costs to the Utah jurisdiction comports with (1) PacifiCorp's transmission planning that led to construction of the Energy Gateway Project, and (2) the principles enunciated by FERC and the Seventh Circuit with respect to cost-causation.

PacifiCorp's 2011 filing for new transmission rates and cost allocation may help inform the Commission in this matter even though the Commission cannot set access charges or set transmission rates for wholesale customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.