- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application	**|**	**Docket No. 02-035-04**
of PacifiCorp for an Investigation	**|**	**Utah Division of Public Utilities**
of Inter-Jurisdictional Issues	**|**	**Exhibit No. DPU 1.0**

Direct Prefiled Testimony of

George R. Compton, Ph.D.
For the Division of Public Utilities
Department of Commerce
State of Utah

July 15, 2004

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Acknowledgment: Judith Johnson, Laura Nelson, Irene Rees, and Michael Ginsberg made valuable contributions to this testimony.

I. Introduction and Qualifications

Q. What is your name, and by whom are you employed?

A. George R. Compton. I am a Technical Consultant in the Energy Group within the Division of Public Utilities (UDPU, DPU, or Division) of the Utah Department of Commerce.

Q. What is your education and work experience?

A.. I hold a Bachelor's Degree from Brigham Young University, with majors in Mathematics and Psychology, and a minor in Philosophy. A portion of my undergraduate experience also took place at Stanford. Subsequent to earning a Master's Degree at BYU in Statistics, with minors in Psychology and Philosophy, I worked for McDonnell Douglas Astronautics in Southern California, principally as a probabilist.

Apart from some part-time teaching at BYU, my entire career since earning a Ph.D. in economics from UCLA in 1976 has been spent in utility regulation. For all but two of those years I have been employed by the Division, on whose behalf I have testified countless times before this Commission. In the two odd years I was an independent consultant. My clients included UAMPS, UP&L, and U S WEST. The main area of my professional interest has been the application of economic principles to utility pricing and costing. For a number of years I was also the Division's primary cost-of-capital witness.

Q. What has been the nature and extent of your participation in the Multi-State Process?

A. Working on the MSP project has been my primary assignment these past two years. My chief role has been in the technical arena, i.e., modeling, compiling numerical studies, etc. Judith Johnson, the manager of the DPU's Energy Section, has established our policies under the direction of Irene Rees, who heads the Division. Laura Nelson, a former DPU employee who was retained as a consultant for the MSP project, acted as a day-to-day technical/policy intermediary – working closely with Judith and myself, and serving as the DPU's lead spokesman in a number of meetings, including those held in Boise with the Oregon PUC staff.

II. Background to, and Brief History of, the Multi-State Process

Q. What has been the primary purpose of the MSP?

A. It has been to get all, or at least all of the largest, of PacifiCorp's state jurisdictions operating under a common set of cost allocations formulas.

Q. What led to the establishment of the MSP?

A. There were a number of factors. The most prominent underlying causes were Oregon's passing of legislation which undercut that jurisdiction’s rate base participation in future generation plants, and Utah’s departure from the “Modified Accord” (under which most of the other States’ allocations were conducted). As a reaction to those developments, which would effectively preclude that company’s ability to recover its full capital costs from past and (most notably) future investments, in December of year 2000 PacifiCorp proposed a Strategic Restructuring Plan (SRP). It would have separated the generation function from the rest of the Company and placed it under FERC jurisdiction.

Troubled by the potential for undesirable consequences of such an action, Utah parties persuaded the Company to first attempt to resolve its concerns through a “multi-state-process” -- or MSP, whose objective was to re-establish a common inter-jurisdictional allocations approach. The Company responded with a pledge to devote a good-faith effort in support of the sought-for MSP consensus. Soon thereafter, Oregon and the other States joined in the process.

Q. Would you please give us a very brief history of the MSP?

A. The initial, formal MSP organizing meeting took place in Boise, Idaho in April of 2002. The facilitator at that and the subsequent large meetings that were held in Las Vegas during the remainder of that year was Robert Hanfling, who had been retained by PacifiCorp. Early submissions for consideration included a list of major items that the Oregon Coalition (comprised of the PUC staff, Citizens’ Utility Board [CUB], and Industrial Consumers of Northwestern Utilities [ICNU]) believed should be incorporated in the allocations methodology, and an “ownership model” proposal that would assign to the jurisdictions fixed portions of the costs and output of the various production resources.

Failing to reach a consensus in that period, and responding to the desire of parties for more detailed and exhaustive technical analyses, the large meetings were suspended during early 2003 in favor of smaller, technical meetings while the Company assembled a large number of quantitative economic studies. During that period, much effort was also expended in developing the “hybrid model” – which was generally favored by Oregon and Washington.

In June of 2003 the Utah parties issued a consensus memorandum reaffirming their strong preference for a dynamic, rolled-in methodology. While “not clos[ing] the door to consideration of an [Northwest hydro] endowment,” it clearly offered no support for the “hybrid” approach.

Following a meeting held in July of 2003, where substantial polarization was observed, the Company took it upon itself to create an analytically sound compromise approach. That product, named the “Protocol,” was filed in the States in September of 2003. A major ingredient was a Utah-Huntington plant “coal endowment.” It was intended to offset the Northwestern hydro endowment. While that particular feature was immediately rejected by most of the parties, there was enough support for other elements of that proposal to encourage the company to continue in its efforts to a) accommodate the Northwest's hydro endowment in a satisfactory manner, b) preserve the most fundamental elements of the Utah "dynamic alternative," and c) to demonstrate that Utah would bear the lion's share of the cost burden of its projected growth.

The product of that effort, filed in May of this year, is now before this Commission. To distinguish it from the original Protocol proposal, it has been labeled the "Revised Protocol." Credit for the parties' having come to some form of consensus around the Revised Protocol rests with the Oregon and Utah Commissioners who voiced their support of a positive MSP resolution, with the "behind the scenes" reinforcement of that support by the Company's hired "facilitator," Bob Hanfling, and with the continued dedication by the parties to finding an acceptable solution.

Q. What was the nature of the Division's commitment to MSP success?

A. Concerned about the Company's future ability to fund a least-cost/risk generation-transmission infrastructure absent a cost-allocation mechanism that was consistent across its region, the Division supported a successful MSP process. An important element of our leadership's vision of the process was a conviction that MSP success depended as much upon achieving consensus among Utah parties as obtaining an agreement between the DPU and the Oregon PUC staff (which also largely spoke for that State's residential consumer board and industrials). In that same vein it was recognized that different parties will have strongly held viewpoints, requiring elements of compromise if there was to be a hope for a satisfactory MSP resolution.

Q. You just spoke of a compromise. Did PacifiCorp also compromise, and if so, how?

A. It did...by stipulating to early-period limitations to how much the revenue requirement otherwise produced by the Revised Protocol would exceed what would have been produced by the fully rolled-in methodology now in effect in Utah.

III. The Revised and Utah-Stipulated Protocols: A Qualitative and Quantitative Overview

Q. From a high level basis, how would you characterize the Revised Protocol?

A. I would say it embodies a strong dynamic, rolled-in orientation, with the following four major departures from the status quo:

1. Company-owned hydro has been re-introduced as a resource dedicated to the former Pacific Power and Light (PP&L) territory (i.e., parts of Oregon, Wyoming, Washington, and California), but the costing differential is based upon full (i.e., fixed plus variable) costs, not just the fuel costs. Unlike the case with Modified Accord, this "endowment" has no *a priori* time limitation but will continue beyond the time when hydro re-licensing costs exceed the fuel cost savings.
2. Rather than being fully shared as a system resource, designated units of the Mid-Columbia (or Mid-C)

hydro purchase contracts are now earmarked as exclusively benefitting Oregon and Washington.

3. There are wide disparities currently in the rates established by the States for compensating Qualifying Facilities (QFs). Instead of having those disparities rolled-in and borne by the system as a whole, the Revised Protocol makes the States individually responsible for the amounts by which the costs from their own QF power sources exceed certain standards.

4. The costs of resources whose intended utilization is concentrated during high load seasons are allocated according to usage in those seasons.

Q. Have the Utah parties agreed to future revenue requirements that are expressly as produced by the Revised Protocol?

A. Not quite. A major element of the stipulation of the Utah parties with PacifiCorp consisted of early-period mitigation measures which generate revenue requirements that are projected to be less than what would come out of the Revised Protocol. To partially offset the reduced revenue requirements in the early years, the Utah parties also stipulated to rates that would exceed the projected Revised Protocol amounts by 0.25% in fiscal years 2010-2012. Looking at the discounted full fourteen-year study period, the combined mitigation measures make the "Utah-Stipulated Revised Protocol" aggregated outcome almost identical to what is projected if the Modified Accord were applied to Utah.

Q. You have said that the stipulated mitigation measures brought our fourteen-year revenue requirement close to Modified Accord results. Have you prepared an exhibit which shows in some detail how the projected revenue requirements produced by the Revised and Stipulated Protocols compare to the status quo?

A. I have. My attached Exhibit ____(GRC-1) shows on a year-by-year basis how Utah revenue requirements produced by the Modified Accord, the Revised Protocol, and the Utah-Stipulated Protocol vary from the Rolled-In approach that has been used in this State for the past several years. Except for the first two fiscal years (2005 and 2006) and the last three in the study (2016-2018), the Modified Accord figures exceed the Rolled-In results by a fairly uniform percentage (about 0.25%). The Revised Protocol figures exceed the Rolled-In values in the first six years, and averages nearly 0.5% below Rolled-In in the last five years. While for the full fourteen year study period in aggregate there is projected to be a virtual equality between the Stipulated Protocol and the Modified Accord, the latter is more favorable in the early years, while the Stipulated Protocol is more favorable in the later years.

To better understand the influence of the later years, I substituted a 5% "social discount rate" for the 8.823% cost-of-capital figure used in the Company's studies. The lower discount rates generates a fourteen-year Stipulated Protocol figure that is shown to be significantly lower than the Modified Accord figure

IV. Distinguishing the Revised Protocol from the Current Rolled-In Method

Q. Would you now please describe qualitatively, but in greater detail than above, the major elements of the Revised Protocol, and how they differ from the status quo here in Utah?

A. Of course, and I will employ the same general topic sequence as is found in the final Revised Protocol document.

1. <u>Classification of Generation Fixed Resource Costs:</u> The status quo approach of classifying such costs as 75% demand-related and 25% energy-related was preserved. The Oregon Coalition proposal to reclassify peaking and baseload plants was not accepted.

2. <u>Seasonal Resources:</u> The Revised Protocol categorized peaking plants and seasonal contracts as seasonal resources, as desired by the Oregon Coalition. The Cholla/APS costs were also categorized as seasonal until the APS exchange contract expires. Both the fixed and variable costs associated with these resources are allocated to the jurisdictions according to their relative use during the relevant seasons. (The Utah status quo does not distinguish resources as seasonal or otherwise. Net power costs, for example, are allocated on the basis of annual energy consumptions.)

3. <u>Regional Resources:</u> The Utah status quo rolls in all of the hydro facilities as system resources. The Revised Protocol dedicates all the Northwest's company-owned hydro to the remaining former PP&L jurisdictions. The computational method for treating that dedication employs a credit based on the difference in average total (i.e., fixed plus variable) embedded costs between the hydro facilities and all other production resources.

   As is the case with the Company-owned hydro, the allocations of the Mid-C purchases' costs are framed in terms of the difference in average total costs between them and all the other generation sources. The distinction is the separation of the portions of the Mid-C purchases which are deemed "system" from the portions that are explicitly dedicated to Washington and/or Oregon by contract. The Oregon/ Washington-specific components of what the Company has called the "Mid-Columbia Contracts Cost Differential Adjustment" is proportional to the share of the total Mid-C MWh output that is comprised of the contracts dedicated to them. The system's balance of that adjustment is allocated to *all* the jurisdictions in proportion to their overall relative "generation demand factors."

4. <u>State Resources:</u> As in the past, each State bears its own costs that are dedicated to demand-side management programs. Insofar as costs associated with alternative production facilities expressly mandated by a particular State's "Portfolio Standards" (e.g., solar or wind power) exceed the costs of

facilities of the same vintage that would have comparable output and delivery characteristics, those costs are assigned to the mandating States. The costs of new Qualifying Facilities within each State will be treated the same way as those mandated under the Portfolio Standards. Apart from its State categorization as opposed to a Regional categorization, existing Qualifying Facilities will be treated in the same manner as the hydro facilities – i.e., by incorporating in each jurisdiction's cost allocation the average embedded production cost (fixed plus variable) differential between that jurisdiction's QFs and the average cost of all other generation. The status quo Utah approach rolls into the system aggregate the costs of all the QF facilities and all the Portfolio Standard facilities, regardless of how generous a particular jurisdiction may have been in establishing the compensation to those facilities.

Q. You have mentioned the embedded average cost differential approach as the employed alternative to the full rolled-in approach to dealing with the hydro facilities, the Mid-C contracts and the QFs. Would you please explain how that approach would work?

A. Attachment A to this testimony consists of a simplified numerical example which I prepared that illustrates how the "embedded cost differential" approach works within a full rolled-in context

Q. Could we take your four items and briefly describe the discourse that led to their respective final Revised Protocol proposals?

A. Surely.

1. <u>Classification of Generation Fixed Resource Costs:</u> The earlier version of the Protocol classified peaking plants as 100% demand (per Oregon's original suggestion). There is substantial theoretical support for such a classification. But that same theory also argues (as did Oregon) for changing the classification of baseload plants from 75% demand and 25% energy to something like 50-50 demand and energy. Because Utah has loads that are seasonally less uniform than, particularly, does Wyoming, reclassifying peaking plants (to 100% demand) while not at the same time reclassifying baseload plant (e.g., to 50% demand) would over-allocate costs to Utah. Given the high degree of controversy regarding this subject, PacifiCorp elected to achieve the essential classification balance by abandoning the peaker reclassification rather than by supplementing it with a baseload plant reclassification.

2. <u>Seasonal Resources:</u> The parties generally agreed that jurisdictions that make heavy demands on the system during periods when certain resources also see their greatest use should bear the greatest share of the costs of those resources. The controversy lay in how to implement that philosophy. For example, it has been, and is still being, questioned whether there has been total consistency in the treatment of all seasonal-appearing resources, and whether single-cycle plants should be categorized as seasonal resources when (contrary to planning expectations perhaps) they in fact have a high capacity factor

(suggesting high year-round use). Because of those concerns, the final Protocol language includes the following (starting on page 4, line 23 of that document):

> The MSP Standing Committee will review Seasonal Resources criteria and allocation. Items to be considered include the seasonal patterns of Resource operation to determine seasonality, the treatment of associated off-system sales, the value of operating reserves provided from Seasonal Resources, criteria to define seasonal Exchange Contracts and methods for allocating the costs of seasonal exchange returns.

3. Regional Resources: Concerns have focused on both the extent of the hydro endowment (e.g., how much of the Mid-Columbia resources should be included) and the technical/computational treatment of whatever was ultimately included. While early on the Utah Parties expressed an openness to consider a hydro endowment, their view of its extent was highly limited. The previously referenced "Dynamic Alternative..." paper (of June, 2003) included the following statement:

> Were Utah Parties to find a hydro endowment acceptable, it could take the form of a fuel cost adjustment, as is now the case in Modified Accord. But this adjustment would be based on PacifiCorp's own hydro resources and pre merger steam plant only. ...[A]s specific hydro plant is relicensed, and thermal plant retired, associated operating costs and output would be removed from calculation of any hydro fuel cost adjustment [i.e., the endowment].

Subsequently (i.e., in its March 5, 2004 memo to the Utah PSC), the Division stated (on page 4), "We continue to believe that a dynamic allocation method [as opposed to a method that incorporated fixed plant assignments] that incorporates a hydro endowment is optimal, given the existing policy differences across jurisdiction[s]." Regarding the Utah Parties' favored fuel adjustment method of dealing with the hydro endowment, that same memo (pp. 12, 13) recognized that, "[h]owever, to date, Oregon has not accepted this approach." Accordingly, the Division actively supported the quest for "a method that more accurately and fairly assigns both the costs and benefits of the hydro resources to Oregon." Furthermore, (on page 14 of that same memo) the Division expressed reservations regarding the fuel cost adjustment approach on the grounds that it allowed the Northwest to keep the substantial fuel-cost advantages of hydro while passing on the high hydro re-licensing costs to the rest of the system. And while the Division had joined in advocating that, as per Modified Accord, all of the Mid-C contracts should be treated as system, rather than regional, resources, that same memo (on pages 14 and 15) reviewed the nuances to the Northwest region's claims to the Mid-C resources that were presented in the Company's legal history of the contractual agreements.

Another argument in favor of designating hydro facilities as regional rather than system resources has to do with the fact that much of the investment in and operation of those facilities may have nothing to do with electricity production per se, but rather with achieving purely regional objectives. I refer to flood control, fishery preservation, and shipping barge accommodation, etc. Given that array of ancillary benefits, and given the difficulty of isolating the purely electrical costs, it is reasonable to have both the full benefits and full costs of the Company-owned hydro system earmarked for the Northwestern/PP&L jurisdictions.

Compromise on the Mid-C matter was achieved by the Revised Protocol proposal that Utah and the other Eastern Division jurisdictions withdraw their claim to the portions of the Mid-C resources whose contracts specified Oregon and/or Washington as the beneficiaries, and that the Northwest in turn relinquish its exclusive claims to the rest of those resources.

As regards the appropriate regulatory/allocations treatment of the hydro endowment, in the beginning of the MSP process the Oregon Coalition took the position that when they achieved their objective of paying for all of the hydro resources, the Northwest should be directly entitled to their entire output. That led to the proposition that that region should only be allocated shares of the costs of the remaining (i.e., non-hydro) resources that were based on the demands placed on those resources that were residual to what had been taken care of by the hydro resources. Such defines the "load decrement approach" to cost allocation in this context.

A number of factors led to the abandonment of the load decrement approach in the development of the Protocol. Most prominent was the understanding that the load decrement process may reduce the obligation of the Northwest to pay for *its own* growth costs or for the greater-than-embedded-average cost of replacing the generation capacity lost to the Northwest as re-licensing downgraded the hydro facilities. The Division's March, 2004 said the following in this regard (on page 18):

> Recall in a dynamic, rolled-in environment that the above-average-costs portion of growth costs are borne in proportion to a jurisdiction's share of the total load or resource pool – i.e., independent of its own load growth. Therefore, by virtue of the decrement adjustment having reduced the Northwest's participation in the general resource pool, the Northwest will end up paying for a smaller-than-otherwise share of its own growth/ replacement costs.

The Revised Protocol adopted neither the fuel-cost adjustment nor the hourly load decrement approach. The conceptual basis of the fuel-cost adjustment was that the hydro endowment would be temporary – lasting until re-licensing costs swamped the fuel cost advantages. That basis was opposed by the insistence of the Northwest parties that the hydro endowment should be permanent, and that total costs rather than fuel costs be recognized. To resolve this matter, the Revised Protocol employs an "embedded cost differential." This approach is more consistent with a rolled-in embedded cost orientation. It reduces (or, as projected for the future, increases) the Northwest region's cost allocation by the amount by which the average cost of its hydro output is beneath (above) the average cost of the non-hydro production.

4. <u>State Resources:</u> The largest-dollar item placed into this category by the Revised Protocol are the

Qualifying Facilities (QFs), which formerly were treated as rolled-in system resources. Oregon currently has the largest and most costly inventory of QFs. Utah giving up its claims to a portion of the Mid-C resources was made more palatable under the auspices of the Revised Protocol by virtue of the relief obtained by the elimination of the system-burden of the high-cost QFs in favor of assigning their associated high costs to the individual jurisdictions on a *situs* basis (i.e., according to where the QFs are located).

V. The Growth Cost Burden

Q. Perhaps the biggest concern behind the specifics of Oregon's advocacy has been its fear of "subsidizing" Utah's relatively rapid growth as a byproduct of a rolled-in allocations process. Does the Revised Protocol introduce specific regulatory/ allocations measures to shield low-growth jurisdictions from the cost burdens imposed by the jurisdiction that is expected to be the fastest growing, i.e., Utah?

A. The closest thing to such a measure is the allocation of peaking resources' costs more in proportion to peak demand and energy consumption during high usage months. The intent of that element of the Revised Protocol is for Utah (or any other jurisdiction whose peak demand grows faster than its annual energy use) to pay a greater share of the costs of any peaking facility that is installed to meet its growth. I would suggest that additional measures do not appear in the Revised Protocol because the growth issue was diffused to a considerable degree by Company studies indicating that under a rolled-in allocations scheme Utah would bear the lion's share of the incremental costs caused by its growth. However this issue is not necessarily dead. There is enough concern regarding it on the part of the Oregon Coalition that, at its insistence, the following language has been incorporated in the Revised Protocol (starting on page 8, line 1):

> In concert with the current IRP cycle, the Company and parties will analyze and quantify cost shifts related to faster-growing States....No later than nine months after the filing [of] the 2004 IRP, the Company in consultation with the MSP Standing Committee and other parties will file a report with the Commissions regarding this [the growth] issue. Included in this report will be a description of one or more options for a structural protection mechanism, detailed with sufficient specificity to allow timely implementation in the event that the studies show a material and sustained net harm to customers in any jurisdiction.
>
> ....
>
> Potential mechanisms to be studied include tiered allocations, treatment of Seasonal Resources, a structural separation of the Company, temporary assignment of the costs of some new Resources to fast-growing States, and the inclusion of measures of recent load growth in the computation of allocation factors.

Q. From that statement out of the Revised Protocol document I would conclude that the subject of growth cross-subsidies is still an issue. How does the Division view this matter?

A. We view it as very complicated, with a number of potentially offsetting components. An example is the requirement to add thermal capacity as a consequence of the reduction of permitted electricity output, which is a major ingredient of the upcoming hydro re-licensing. Adding X megawatts of capacity to replace some lost capacity from another source is more onerous to the rest of the customers than would be adding X megawatts of capacity to serve Y megawatts of load growth. That is because in the latter case the new loads will themselves be allocated a portion of the amount by which the incremental costs exceeds the embedded, average costs. By contrast in this example, hydro capacity replacement costs would not have the additional Y megawatts of load growth to help pay for them.

I would add that the DPU's concern over the hydro-replacement burden is one reason to believe that the hydro endowment of Company-owned facilities should not be rendered irrevocably permanent. It wouldn't seem right for the Northwest to reap all the benefits of low-cost hydro while shifting most of the burden of hydro's replacement costs to the rest of the system. In my mind, the most likely scenario behind a future return to a fully rolled-in allocations approach will be where hydro replacement costs and growth costs are viewed as comparably burdensome (or non-burdensome), and where the Northwest agrees that the extra regulatory effort of keeping track of different plant entitlements under the Revised Protocol is not justified.

VI. Some Policy Justifications

Q. Given the policies embraced by the Division in the past, particularly its advocacy of the fully rolled-in methodology, why did it agree to the Stipulated Protocol now?

A. The Division, along with all the other Utah Parties as well as the Oregon parties (and the Company itself) were willing to make some compromises in the interest of achieving an MSP agreement. Along with the financial integrity benefits described earlier, the Division also received assurances from the Company regarding various policy commitments that would enhance our reliability or shrink our growth burdens.

Q. The fact that the output of all the generation resources can be viewed as combined into a giant common pot (with the jurisdictions withdrawing from that pot according to their momentary needs) has been used as a theoretical justification for fully rolled-in cost allocations. In your estimation are there also economic theoretical justifications for departing from that approach, particularly with respect to the hydro resources?

A. There are. But let me preface my answer by remarking that the advantages of fully rolled-in allocators in terms of simplicity, regulatory transparency, and stability are probably universally recognized. The MSP studies also indicate that the rolled-in methodology does an adequate job of placing the costs of growth on the growing jurisdiction. Beyond that, the fact that an integrated set of resources provides joint use does not by itself justify, much less mandate, a rolled-in approach to cost allocation. Parties can agree to some alternative vehicle of cost sharing without compromising system integration benefits.

Economic theory can shed light on why that should be so. Particularly relevant is the notion of a Pareto-efficient transaction, which is defined as something that provides value to at least one party while causing no party to lose value. On the margin, economic inefficiency follows from a failure to consummate a Pareto-efficient transaction. The presumption is that rational actors won't freely submit to or choose a non-Pareto-efficient outcome.

Consider a simple, illustrative example. Let there be two utilities, A and B, of equal size and output. Now assume that A's average cost is 5, while B's average is 10. The overall average is therefore 7.5. Suppose that efficiencies of integration – where both of the utilities' former resources come to be used jointly by both of their sets of customers – would allow the overall system average to decline by 20%, to 6. Clearly, those utilities should merge or otherwise integrate in order to reap those savings. But the customers of A will reject the merger if a fully rolled-in allocator must accompany it. Obviously, A would never give up an average cost of 5 in order to be saddled with an average cost of 6. To achieve Pareto-efficiency in this example would require the adoption of some allocations approach which recognizes the less costly resources of utility A. An insistence upon employing a fully rolled-in cost allocations approach would prevent the transaction and deny the potential benefits to both parties. In this example, the value of Pareto efficiency would likely supercede any value that might have derived solely from a rolled-in allocator.

In our context, hydro constitutes the "less costly" whose benefit the Northwest is unwilling to give up. In that regard, the Division's MSP memo of March 5, 2004 (page 11) included the following discussion:

> Through the MSP, the Division has come to understand that the public in the Northwest states believes it is entitled to all the hydropower from that region, [and] at cost. Oregon has expressed that it would not have approved the [Pareto-efficient] PP&L-UP&L merger if it thought that the benefits of these resources would be displaced. Specifically, some Oregon parties have stated that the primary indicator of not being made worse off by joining with UP&L seems to be enjoying the undiluted benefits from the low-cost hydropower in the region.

Another insight from economic theory comes from the distinction between long-run and short-run costs. Generation resources, including hydro facilities, have high costs and long lives, and are installed to meet anticipated, then-future loads. Such resources can also be divested if excess capacity is projected. The acts of acquiring or not divesting generation resources fall in the realm of long-run costs. Utah loads were not a factor in the original acquisition of the hydro resources (which occurred prior to the UP&L-PP&L merger). And the loss of the Utah loads would not result in the divestiture of those same resources. In other words, Utah loads haven't affected in the past, nor will affect in the future, the long-run costs associated with the hydro resources.

Now consider short-run costs, which are associated with the contemporaneous operation of generation facilities. Due to the very low running costs of hydro facilities, they will ordinarily be operated to the maximum desired extent independent of Utah (or Eastern control area) loads. That means that for all intents and purposes the hydro facilities serve loads in the Northwestern region. Any tendency to utilize the limited West-East transmission capability to accommodate Utah loads from Northwestern control area resources (on the margin) will most likely be met by an increased output from that control area's thermal resources. To conclude, it is difficult to make a case that Utah's loads affect either the long-run or the short-run costs of the Northwestern hydro facilities to a material degree.

Q. Accepting the inevitability of a hydro endowment for the Northwest, why doesn't the Protocol include the "transmission endowment" as a credit for the former UP&L jurisdictions, and as a substitute for the previously proposed "coal endowment"?

A. The transmission endowment was pursued by way of some information requests of the Company. It hasn't received an explicit, quantitative place in the Revised Protocol for several reason, including the following:

1. The very nature of a transmission endowment has been difficult to specify and to, in turn, quantify.
2. The aspect of that endowment that was previously quantified (as part of the original Accord methodology) has diminished greatly in value.
3. FERC's transmission open access ruling has allowed third party wheeling across the PacifiCorp's lines in lieu of what had previously been favorable UP&L arbitrage opportunities (where it bought from a low-priced producer and sold into a market that was experiencing a shortage and the associated high prices).
4. A counter-argument to a claim that the former UP&L jurisdictions may not be reaping the appropriate value from a transmission endowment is Oregon's claim that the Revised Protocol under-values the hydro endowment on behalf of the former PP&L jurisdictions.

Q. You have alluded to the commitment that PacifiCorp made to the Northwest as a merger condition, i.e., that it would not be harmed by the union. What about the commitment made to Utah that the Company would accept the risk of the States not coming to an agreement regarding inter-jurisdictional allocations?

A. When PacifiCorp made that commitment it was undoubtedly optimistic about how easy it would be to get the States to agree with one another on inter-jurisdictional allocations. The presumption was that States would make a good-faith effort to achieve a common allocations basis. Agreements that have been achieved in the past, plus the Revised Protocol itself, represent the culmination of such efforts.

VII. A Procedural Innovation Introduced by the Revised Protocol

Q. You have described substantive areas where modifications to the allocations status quo are being proposed. How about the procedural realm? Is there something new in that regard?

A. There is. The creation of an "MSP Standing Committee" is being proposed. It would consist of a Commissioner or designee from each jurisdiction. That Committee would appoint a "Standing Neutral," funded by the Company, who would "facilitate discussion among States, monitor issues and [otherwise] assist the...Committee." It is contemplated that the Standing Neutral and Standing Committee will gather at least once a year in an open meeting to address whatever issues various parties or jurisdictions bring to them. Supporting the Standing Committee in it efforts to reach "equitable" and "consensual" resolutions of the various matters brought to its attention would be task forces drawn from interested parties and/or disinterested parties. The latter would be "retain[ed] (at the Company's expense)." Formal resolutions will be in the form of "Proposed amendments to the Protocol [which] will be submitted by PacifiCorp to each Commission for ratification."

VIII. Pending Issues for Consideration by the Standing Committee

Q. Will the Standing Committee be charged with any immediate issues to resolve or studies to complete?

A. They will. The two explicit assignments were described earlier in this testimony. One was the extensive "review [of] Seasonal Resources criteria and allocation." The other was the development of "one or more options for a structural protection mechanism" against an unreasonable shift of the cost burden of growth onto the non- or slow-growing jurisdictions.

Q. Are there other issues that the Standing Committee may be called upon to address in the foreseeable future?

A. As you can imagine, if we were to await perfection in the formulation of the Revised Protocol, who knows how long it would take before an allocations approach could be adopted uniformly across the jurisdictions. One area that will likely require more attention is the treatment of special contracts that provide system benefits due to interruptibility, etc. Another area which I believe is problematic has to do with Direct Access. It is not an immediate problem because as of this writing there are no Direct Access customers in the PacifiCorp system. The Revised Protocol states that when Direct Access customers do present themselves, the "process [of incorporating that status within separate allocation factors for new and existing resources] will be implemented under the guidance of the MSP Standing Committee."

Q. Does that conclude your testimony?

A. It does, thank you.