BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WUTC V. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY

DOCKET NOS. UE-050684 and UE-050412

DIRECT TESTIMONY OF CHARLES J. BLACK (CJB-1T)

ON BEHALF OF

PUBLIC COUNSEL

November 3, 2005

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I. INTRODUCTION AND SUMMARY

Q. Please state your name, occupation and business address.

A. My name is Charles J. Black. I am self-employed as an independent consultant and owner of Charles J. Black Energy Economics. My address is 12728 SE 86th Place, Newcastle, Washington 98056 (e-mail: cjbenergy@msn.com)

Q. Briefly describe your educational background.

A. I hold a Bachelor of Arts degree in mathematics and economics from Western Washington University and a Master of Arts degree in economics from the University of Washington.

Q. Please summarize your professional experience.

A. I have over 23 years of experience in the electric and natural gas utilities industry. The majority of my experience has focused on various aspects of energy resource matters including planning, forecasting, analysis, acquisition, risk management, contracts, marketing and regulatory issues. During the first 19 years of my career I was employed by three utilities, beginning with Pacific Gas and Electric Company (1982-1991), followed by Tacoma City Light (1991-1997), and finally Puget Sound Energy (1997-2001). During the last several years I have worked as a consultant.

Q. What types of consulting services do you provide?

A. My current consulting practice focuses on integrated resource planning, resource acquisition, and resource portfolio management. I provide consulting services to utilities and to other entities.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Public Counsel Section of the Washington State Attorney General's Office.

Q. Have you previously testified or otherwise appeared before the Washington Utilities and Transportation Commission?

A. Yes. In 1999, I appeared as a witness on behalf of Puget Sound Energy (PSE) in the complaint proceeding regarding PSE's Schedule 48 (Docket No. UE-981410). On July 21, 2003, I presented a summary of PSE's 2003 Least Cost Plan at a Special Meeting of the Commission (Docket Nos. UE-030594 and UE-030595). On October 24, 2003, my pre-filed direct testimony on PSE's 2003 Least Cost Plan (including its relationship to PSE's resource acquisition activities) was submitted as part of PSE's Power Cost Only Rate Case filing (Docket No. UE-031725).

II. TOPICS ADDRESSED IN THIS TESTIMONY

Q. What topics do you address in your testimony?

A. My testimony addresses three topic areas related to PacifiCorp's power costs. First, I describe how PacifiCorp has not demonstrated prudency in its recent acquisitions of new electric resources.

Second, I explain that PacifiCorp has not demonstrated that its request to implement the Revised Protocol in Washington State would accurately allocate power costs to its customers in Washington State.

Third, I identify the need to address PacifiCorp's resource decision-making processes and properly align incentives of employees involved in those processes before implementing a Power Cost Adjustment Mechanism (PCAM) for PacifiCorp.

III. PACIFICORP HAS NOT DEMONSTRATED PRUDENCY FOR NEW RESOURCES IT HAS ACQUIRED

Q. In your opinion, has PacifiCorp demonstrated that the new electric resources it recently added to its power supply portfolio were prudently acquired?

A. No, it has not.

Q. What leads you to reach this conclusion?

A. In brief, PacifiCorp did not follow adequate processes or perform appropriate analyses to solicit and evaluate specific candidate resources. Consequently, direct testimony by PacifiCorp's witnesses does not show that the company made prudent decisions about the new electric resources that it acquired.

Q. In your opinion, what were some of the more significant drawbacks in PacifiCorp's evaluation of specific candidate resources?

A. In this portion of my testimony, I focus on two drawbacks in PacifiCorp's evaluation of specific candidate resources. One significant drawback was that PacifiCorp's evaluations did not analyze net impacts of specific candidate resources on the overall portfolio of resources that PacifiCorp uses to serve its retail electric customers. Instead, PacifiCorp evaluated, compared and selected specific candidate resources on essentially a stand-alone basis. A second, related drawback was that PacifiCorp used commodity valuation measures as a primary basis for its evaluations of specific candidate resources. Such measures are commonly used for speculative trading purposes but do not provide an appropriate basis for decision-making about electric resources to be used by a vertically integrated utility to serve the needs of its retail customers.

A. RATHER THAN ANALYZING AND SELECTING NEW RESOURCES IN TERMS OF NET IMPACTS ON ITS OVERALL PORTFOLIO, PACIFICORP RELIED ON STAND-ALONE EVALUATIONS

Q. Let's focus on the first drawback that you have identified. Please explain how PacifiCorp's evaluations of specific candidate resources did not analyze net impacts on PacifiCorp's overall portfolio.

A. In my review of the pre-filed testimony for PacifiCorp's witnesses, there was little to indicate that PacifiCorp had systematically analyzed or compared net impacts of specific candidate resources on PacifiCorp's overall electric resource portfolio. For example, the testimony did not document any systematic analysis by PacifiCorp of net impacts of specific candidate resources on cost, risk, reliability, environmental impacts or other objectives for its overall portfolio.

Q. When evaluating specific candidate resources, why is it more important to analyze expected net impacts on the utility's overall resource portfolio, rather than focusing on stand-alone characteristics of the candidate resources?

A. In Washington State, a regulated, cost-of-service utility such as PacifiCorp uses an integrated portfolio of electric resources to provide service to its retail electric customers. Individual resources are not planned, acquired or operated on a separate basis to serve specific retail electric customers. As a result, what impacts customers and matters most is the overall performance of the utility's electric resource portfolio, not the stand-alone characteristics of individual resources within the portfolio.

Q. But if a specific new resource is most attractive on a stand-alone basis (e.g., in terms of its cost, risk, reliability and environmental impacts), doesn't that

mean it will produce the most beneficial net impacts on the utility's resource portfolio as a whole?

A. Not necessarily and not even usually. Configuring a portfolio to include a mix of several types of resources with features that complement each other often produces better overall results than haphazardly mixing resource types or relying too heavily on one resource type. One example involves wind power. When viewed on a stand-alone basis, other types of resources may appear superior to wind power. However, when analyzed from an integrated portfolio perspective, the beneficial net impacts that wind power can provide become more apparent.

Q. Please explain.

A. Wind power does not consume fossil fuels, but its production of electricity varies with local wind conditions. Viewed on a stand-alone basis, wind power may not meet reliability requirements for serving a utility's retail electric customer needs, due to its intermittent generation. However, a number of utilities are finding that other types of resources in their resource portfolio can be used to provide 'back up' for fluctuations in the output of new wind power resources, thereby meeting reliability needs. An additional benefit from this example of resource portfolio diversification is that wind power can reduce the utility's need to add new conventional thermal generation, thereby limiting the resource portfolio's exposure to market prices for natural gas or other fossil fuels as well as environmental impacts.

Q. Do electric utilities use an integrated portfolio approach to determine their long-term electric resource strategies?

A. Yes. For example, in its 2003 and 2004 Integrated Resource Planning (IRP) processes, PacifiCorp used an integrated portfolio approach to analyze candidate portfolios composed of various mixes of resources. In fact, in its recent IRPs, PacifiCorp has become a recognized leader in using an integrated portfolio approach to systematically evaluate a wide range of resource strategies. This kind of approach enables the utility to systematically analyze how different types of new resource additions will interact with each other and with existing resources in the utility's portfolio.

Q. What types of objectives for its electric resource portfolio did PacifiCorp identify in its recent IRPs?

A. PacifiCorp used objectives such as cost, risk, reliability, and environmental impacts. Further, the analysis and decision-making emphasized these objectives for the overall electric resource portfolio, rather than focusing more narrowly on the stand-alone characteristics of individual resource types.

Q. What are some of the benefits of this approach?

A. The portfolio approach and the objectives used by PacifiCorp in its IRPs helps make decision-making more open and transparent, including decisions that typically require balancing of tradeoffs among multiple objectives. This type of approach also helps a utility develop a more robust resource strategy that identifies the types, amounts and timing for addition of new resources that will produce the best results for the utility's overall resource portfolio.

Q. Did PacifiCorp use an integrated portfolio-based, multiple-objective approach as part of its resource acquisition efforts, particularly in its evaluation of

specific candidate resources, including proposals it received in response to Request for Proposals (RFP)?

A. Not in an organized and systematic fashion.

Q. What leads you to reach this conclusion?

A. I have reached this conclusion following review of the pre-filed direct testimony of PacifiCorp's witnesses, particularly that of Mark R. Tallman Exhibit No. ____ (MRT-1T). Mr. Tallman states that the purpose of his testimony "is to provide information regarding the prudence of the Company's supply-side resource acquisitions since 2000." Exhibit No. ____ (MRT-1, pp. 1-2) Mr. Tallman's testimony describes the approach used to solicit proposals, evaluate specific candidate resources, and select the power supply resources that PacifiCorp has acquired during the last five years. The testimony includes descriptions of processes used to acquire a number of resources. These processes included the RFP that PacifiCorp issued in September 2001, RFP (2003-A) issued in June 2003, RFP 2003-B issued in February 2004, and RFP 2004-X issued in July 19 2004 (and reissued July 28 2004). The testimony also identifies several resources that PacifiCorp acquired without using an RFP process.

Q. Since PacifiCorp used an integrated portfolio approach for its IRP analyses, doesn't that mean there was no need to perform such analyses again when it was evaluating specific candidate resources?

A. No. PacifiCorp's recent IRPs analyzed candidate resource portfolios composed of *types* of potential new resources (e.g., wind power, combined-cycle natural gas-fired combustion turbines, etc.) rather than specific candidate resources. The IRPs

appropriately used generic assumptions about costs and other characteristics for each resource type. However, costs, availability or other characteristics for *specific* candidate resources may differ significantly from what was assumed in a utility's most recent IRP. Such differences between generic assumptions about resource types used in an IRP and updated or actual information about specific candidate resources may – and should – lead the utility to acquire specific new resources that diverge from those identified in its most recent IRP. Therefore, when PacifiCorp is making decisions to acquire new resources it is important that it (a) consider the characteristics of the specific candidate resources that are actually available to it, and (b) analyze the net impacts of the specific candidate resources on its overall electric resource portfolio.

Q. Can you provide a few examples of the differences that may occur between assumptions made about resource types in an IRP and actual or updated information that becomes available during the acquisition process?

A. Yes. One example could be a significant shift in the outlook for the cost of fuel for a particular type of resource, such as we have recently seen with market prices for natural gas used in combustion turbines. Another example could be an unexpected technological breakthrough that significantly lowers the cost or otherwise improves the attractiveness of a particular type of resource. Other examples include special opportunities that may make a specific candidate resource less costly, or that provide unique and valuable attributes that are not generally available for that type of resource.

Q. Earlier, you described how adding a certain *type* of resource may create better net impacts for a utility's overall electric resource portfolio than might be apparent using only stand-alone evaluation. What about multiple competing specific candidate resources (e.g., power supply proposals submitted in response to an RFP) where all proposals are based on the same type of resource?

A. Here again, analysis of the competing alternatives is more meaningful when the net impacts of each proposal on the overall portfolio are considered.

Q. Please illustrate what you mean.

A. I can illustrate with an example for combined-cycle combustion-turbine (CCCT) generation that burns natural gas. Suppose a utility identifies a need for energy and capacity during summer months but not during winter months, and issues an RFP. One or more RFP respondents may submit proposals to sell power from their respective CCCT projects to the utility on a year-round basis. However, one or more other RFP respondents may be able to structure proposals to provide power supply from their CCCT project to the utility only during the summer months, with the RFP respondent retaining rights to output from the CCCT during the remainder of the year (e.g., for power sales to other customers, perhaps in another region). Clearly, these two approaches to acquiring the same basic type of resource would have differing net impacts on costs, risks and other objectives for the utility's overall electric resource portfolio. The differences in impacts would be obscured by evaluation of proposals on a stand-alone basis, using measures such as mark-to-market valuation.

Q. Can you provide another example?

A. Yes. One or more responses to an RFP may be based on CCCT projects whose fuel supply depends on ongoing spot market purchases of natural gas, while other respondents' proposals may be able to submit proposals for CCCT projects that also include long-term fixed-price contracts for natural gas. Again, the net impacts of these two approaches on costs, risks, and other objectives for the utility's overall portfolio could differ significantly, but would be largely obscured by stand-alone evaluation of proposals.

Q. If a utility provides information about its resource needs that goes beyond high-level descriptors such as "base load energy" or "peaking capacity", can that help respondents develop better proposals?

A. Yes, as can be seen from the discussion immediately above. A useful goal is to provide information that assists prospective respondents in developing proposals that are targeted to the utility's specific situation and needs without limiting creative solutions.

Q. In your opinion, did the RFPs that PacifiCorp recently used to acquire new electric resources provide this kind of information?

A. No. The RFPs used descriptions of power supply products that were similar to the standard commodity products traded in the wholesale power market. They did not provide additional information that could have assisted prospective respondents in crafting proposals to meet PacifiCorp's actual needs for new resources.

Q. How did PacifiCorp define its resource needs for the RFP it issued in September 2001?

A. Mr. Tallman's testimony states that PacifiCorp issued its September 2001 RFP in response to its projected need for "additional flexible generation resources to allow it to meet seasonal East-side peak demand." Exhibit No. ____ (MRT-1T, p. 3) "The Company's goal was to secure cost-effective resources to meet its East-side capacity requirements." Exhibit No. ____ (MRT-1T, p. 3)

Q. How did PacifiCorp evaluate the proposals that it received in response to its September 2001 RFP?

A. Mr. Tallman's testimony states that each proposal was:

> evaluated based on the following criteria: (1) net value (PV$) against then current market; (2) net value (PV$) per 100 MW of capacity against the then current market; (3) dispatch flexibility; (4) point of delivery to PacifiCorp's system; (5) delivery period (shaped June through September, annual); (6) capacity delivered (MW); (7) term (3 years, 10 years, other); (8) firmness (firm, unit contingent). Exhibit No. ____ (MRT-1T, p. 5).

Q. Would use of these criteria produce an analysis of the net impacts of specific candidate resources (i.e., proposals received in response to the RFP) on PacifiCorp's overall electric resource portfolio?

A. No. With one partial exception, each of the criteria listed relates to the characteristics of a specific candidate resource (i.e., proposal) on a stand-alone basis. None of the criteria provides an indication of the net impacts of a specific candidate resource (i.e., proposal) on PacifiCorp's overall electric resource portfolio. More specifically, PacifiCorp's use of these criteria did not show the net

impacts of a specific candidate resource (i.e., proposal) on overall cost, risk, reliability, environmental impacts, or other characteristics of its electric resource portfolio.

Q. You indicate that one of the criteria may be a partial exception to stand-alone evaluation. Which criterion is that?

A. The fifth criterion that PacifiCorp used was "delivery period (shaped June through September, annual)" Exhibit No. ____ (MTR-1T, p. 5). This criterion moves part of the way toward addressing how well specific candidate peaking resources might meet a need for peaking resources in PacifiCorp's East control area. However, to be useful, the criterion requires analyzing how different seasonal profiles for the specific candidate peaking resource proposals would impact PacifiCorp's portfolio. Such an analysis was not performed, and therefore the criterion was not properly applied.

Q. What are some other undesirable consequences of the criteria and evaluation approach that PacifiCorp used?

A. First, evaluating specific candidate resources without addressing their impacts on the utility's portfolio requires the utility to rely more extensively on making its own subjective judgments when deciding which specific candidate resources (i.e., proposals) to acquire. As a result, this makes the utility's decision-making less open and transparent, increases the possibility of arbitrary or biased decisions by the utility and makes it more difficult to clearly document the basis for the decisions made.

Q. Do you mean to say that none of the criteria that PacifiCorp used were relevant, or that PacifiCorp completely disregarded how specific candidate resources (i.e., proposals) would impact its electric resource portfolio?

A. No, that is not what I mean. Instead, I believe that PacifiCorp did not perform a sufficiently complete, consistent and systematic evaluation to enable it to make – and demonstrate – prudent decisions about the specific candidate resources it rejected and the ones it acquired for its electric resource portfolio.

Q. Please explain in further detail.

A. Mr. Tallman's testimony indicates that PacifiCorp rejected a number of proposals it received in response to its September 2001 RFP "because they failed to provide the necessary flexibility the Company was seeking, offered products that did not meet the Company's needs, or were priced out of the market." Exhibit No. ____ (MRT-1T, p. 6) Meanwhile, Mr. Tallman's testimony claims that the West Valley Lease (one of three resources PacifiCorp acquired as a result of the RFP to serve growing loads in its East control area, particularly Utah) provides various benefits, including "units that can be deployed as necessary in response to changing load, generation or transmission conditions on the system" Exhibit No. ____ (MRT-1T, p. 7), the project "can be dispatched based on changing market conditions to either displace higher cost resources or sell excess power into the wholesale markets" Exhibit No. ____ (MRT-1T, p. 7), the "project provides system benefits by increasing resource diversity, increasing voltage support and reliability" Exhibit No. ____ (MRT-1T, p. 7), and "it avoids transmission costs and constraints historically incurred in meeting summer peak load in the East control area". Exhibit No. ____ (MRT-1T, pp. 7-8)

Each of these claims regarding candidate resources (i.e., proposals) that PacifiCorp acquired *and those that it rejected* may be valid. Unfortunately, the method that PacifiCorp used to evaluate specific candidate resources relied on quantifications that were made separate from PacifiCorp's overall electric resource portfolio. In addition many of the assertions about portfolio impacts are qualitative or are not based on systematic evaluation. Therefore, PacifiCorp has not demonstrated that the resources it acquired achieve the objectives for its overall portfolio better than the proposals it rejected. Further, its decision-making was not sufficiently open and transparent, including for the purposes of determining prudency.

Q. How did PacifiCorp define its resource needs for the RFP (2003-A) that it issued in June 2003?

A. The 'Purpose and Scope' section of RFP 2003-A began as follows:

> "The purpose of this document is to prescribe the process by which PacifiCorp will request and evaluate proposals from third parties to fulfill a portion of the supply-side resource need identified in PacifiCorp's Integrated Resource Plan (IRP)." Exhibit No. ____ (MRT-11, p. 3).

Table 2 of the RFP specified that PacifiCorp was seeking three types of resources, all for delivery to its East control area: (a) 225 MW of "Superpeak" power supply to be delivered during hours ending 1:00 pm to 8:00 pm, beginning June 1, 2004; (b) 200 MW of "Peakers" power supply to be available at PacifiCorp's option to call upon generation daily, beginning April 2005; and (c) 570 MW of "Base load" power supply beginning April 2007. Exhibit No. ____ (MRT-11, p. 4)

Q. How did PacifiCorp evaluate the proposals that it received in response to RFP 2003-A?

A. RFP 2003-A indicated that PacifiCorp intended to evaluate proposals on the basis of Price Factors, weighted up to 70 percent, and Non-price Factors, weighted up to 30 percent. Evaluation of the Price Factors for each proposal was based on a "mark-to-NBA" comparison, where the NBA represented PacifiCorp's Next Best Alternative, consisting of the lower of (a) PacifiCorp's proprietary forward price curve as of July 22, 2003, or (b) the cost for PacifiCorp to build, own and operate a similar resource. Evaluation of the Non-price Factors for each proposal was based on Operational Non-Price Factors (degree that PacifiCorp has the option to dispatch the resource) and Environmental Non-Price Factor Weightings (adjustment factors based on resource type). Exhibit No. ____ (MRT-11, pp. 11-14).

Q. How were the Price Factors and Non-price Factors used?

A. RFP 2003-A noted that the Price Factors and Non-price Factors were to be added together for each proposal and the resulting scores used to determine which proposals would be selected for post-bid negotiations. Exhibit No. ____ (MRT-11, p. 11) The RFP also stated "It is PacifiCorp's intent to negotiate both price and non-price factors during post-bid negotiations." Exhibit No. ____ (MRT-11, p. 13)

Q. Did use of these criteria (i.e., Price Factors and Non-price Factors) and this approach produce an analysis of the net impacts of specific candidate resources (i.e., proposals received in response to the RFP) on PacifiCorp's overall electric resource portfolio?

A. No, for the same reasons that I listed in my discussion above regarding the RFP PacifiCorp issued in September 2001. The criteria only addressed each specific candidate resource (i.e. proposal) on a stand-alone basis, and did not provide an

adequate basis for evaluating net impacts on cost, risk, reliability and environmental impacts for PacifiCorp's electric resource portfolio.

Q. In your earlier discussion of PacifiCorp's September 2001 RFP, you described undesirable consequences of the criteria and evaluation approach that PacifiCorp used. Do you have similar concerns about what was used for RFP 2003-A?

A. Yes. Neither RFP 2003-A nor Mr. Tallman's pre-filed direct testimony provides evidence that proposals were evaluated beyond a stand-alone basis. There was no indication that net impacts on cost, risk, reliability or environmental impacts for PacifiCorp's overall electric resource portfolio were analyzed. In addition, the judgments PacifiCorp made to select specific resources as a result of RFP 2003-A are not described. Rather, it appears that decisions were made mainly on the basis of comparing scores for each proposal in terms of the Price Factors and Non-price Factors listed above.

Q. Your testimony above regarding new resources that PacifiCorp acquired via the RFPs issued September 2001 and in its RFP 2003-A (issued in June 2003), identifies a number of concerns about the methods used to analyze specific candidate resources and to make resource acquisition decisions. Do these same concerns apply to other new resources that PacifiCorp has recently acquired?

A. Yes, including the majority of new resources acquired via other processes described in Mr. Tallman's pre-filed direct testimony. While PacifiCorp used a variety of methods and criteria to evaluate alternatives and select new resources for acquisition, none of the analyses or decisions appeared to systematically address net

impacts on PacifiCorp's overall electric resource portfolio. As a result, I do not believe that PacifiCorp has demonstrated prudency of the electric resources it has recently acquired.

Q. Isn't it overly difficult and time-consuming for a utility to evaluate each specific candidate resource in terms of its net impacts on the utility's overall electric resource portfolio?

A. No. One available approach is to use a computerized model that represents the utility's existing portfolio of electric resources, plus the types, amounts and timing for new resources identified in its most recent IRP. The utility must also develop and input to the model long-term forecasts of electrical demands for the utility's retail electric customers, plus forecasts of wholesale market prices for electricity, market prices for fuel supplies and other assumptions.

Q. Must the portfolio model and all of the input data be developed from scratch for use to evaluate specific candidate resources?

A. No. If the utility has recently completed an IRP, a usable model and the majority of the base data needed are already available.

Q. Does any additional data need to be gathered or prepared?

A. Yes, three types of data are also needed. First, long-term forecasts of wholesale market prices for electricity, market prices for fuel supplies and other base data must be reviewed to determine whether they have changed enough since the last IRP was completed to merit updating them.

Second, assumptions about the cost, availability and other characteristics of generic new resources must be reviewed to determine whether they have changed enough since the last IRP to merit updating them.

Third, information from specific candidate resources, including proposals received in response to the utility's RFP, must be prepared for input to the model.

Q. Once the model and data have been prepared, how are specific candidate resources evaluated?

A. A specific candidate resource can be evaluated by representing it in the model as an addition to the utility's portfolio, while also making an offsetting reduction in the amount of the corresponding generic resource type. Then the model is operated to produce results that identify how well the overall resource portfolio, including the specific candidate resource, performs in terms of objectives such as cost, risk, reliability and environmental impacts. This process is repeated for a number of specific candidate resources, including evaluating the impacts of each on overall portfolio cost, risk, reliability and environmental impacts. Then, the net impacts on the utility's overall electric resource portfolio can be compared across each specific candidate resource.

Depending on the size and types of resources that the utility needs to acquire at a given point in time, this approach can also be used to evaluate various combinations of specific candidate resources for their net impacts on the utility's overall electric resource portfolio. For example multiple proposals for one type of resource, or multiple proposals that combine more than one type of resource could be evaluated for their net impacts on the utility's overall electric resource portfolio.

Q. Is it necessary to perform detailed portfolio modeling for each and every proposal that the utility receives?

A. No, initial screening processes can be used to eliminate proposals that obviously do not meet the utility's needs or are otherwise unacceptable.

Q. The process that you just described could seem rather elaborate and complex. Is it really worthwhile for a utility such as PacifiCorp to invest the time, effort and cost needed to perform this type of analysis to help guide its acquisition of new electric resources?

A. Yes, I strongly believe that portfolio-based evaluation of specific candidate resources is valuable, important and cost-effective. PacifiCorp recently began what it expects will be an ongoing process to acquire an unprecedented quantity (approximately 2,300 megawatts) of new electric resources whose net present value costs will amount to multiple billions of dollars. Sound, systematic evaluations that are well documented provide a clear basis for making resource acquisition decisions that will significantly affect consumers for many years to come.

Q. Are you aware of any other utility in Washington State that is evaluating specific candidate resources in terms of their net impacts on the utility's overall electric resource portfolio?

A. Yes. I designed, recommended and participated in implementing this type of resource evaluation process for Puget Sound Energy (PSE) in 2003. The approach has been well accepted and was successfully used by PSE as the analytical foundation for its recent acquisitions of new power supply resources. PSE is

continuing to use this approach, including for its most recent Power Cost Only Rate Case (PCORC) filing (Docket No. UE-050870).

B. PACIFICORP'S USE OF COMMODITY VALUATION MEASURES DOES NOT PROVIDE AN ADEQUATE BASIS FOR EVALUATING OR SELECTING NEW RESOURCES

Q. Near the beginning of your testimony you identified a second drawback to the approach that PacifiCorp used to evaluate specific candidate resources. What approach was it?

A. PacifiCorp used commodity valuation measures as a primary basis to evaluate, compare and select specific candidate resources.

Q. What types of commodity valuation measures did PacifiCorp use?

A. PacifiCorp has used two basic types of measures. The first involved calculation of the mark-to-market value of the energy from a specific candidate resource and the second involved calculation of option values (e.g., dispatchability, spark spread optionality) for the resource.

Q. Please identify examples of the resources that PacifiCorp acquired using these commodity valuation measures.

A. Mr. Tallman's pre-filed direct testimony describes a number of such resources, including: (a) the Currant Creek Project, a 525 MW natural gas-fired combined-cycle combustion turbine project (CCCT) Exhibit No. ____ (MRT-1T, p. 22); (b) the West Valley Lease, a 200 MW natural gas-fired single-cycle combustion turbine project (SCCT) Exhibit No. ____ (MRT-1T, p. 2); (c) two 100 MW day-ahead call options for delivery of physical power Exhibit No. ____ (MRT-1T, p. 5); (d) retention of the West Valley Lease option Exhibit No. ____ (MRT-1T, p. 14); and

(e) the Gadsby Project, a 120 MW SCCT project Exhibit No. ____ (MRT-1T, p. 18). These examples include 825 MW of new natural gas-fired generation.

Q. Please summarize how a mark-to-market valuation is calculated.

A. In this context, determining the mark-to-market valuation for energy from a specific candidate resource involves calculating (a) the expected net present value (NPV) cost of power from the resource over its term (e.g., the operating life for an owned generating resource, or the contract duration for a long-term power purchase agreement), and comparing it to (b) the expected NPV cost to buy an equal amount of power in the wholesale spot market. If the expected NPV cost of power from the resource is less than the expected NPV cost of spot market purchases, then the resource has a positive mark-to-market value.

Q. How is the expected NPV cost to buy power in the wholesale spot market calculated?

A. In order to calculate the expected NPV cost of buying power in the wholesale spot market, a forecast of spot market prices for electricity is needed. If a long-term resource is being evaluated, then a long-term forecast of spot market prices must be used.

Q. How certain are long-term forecasts of spot market prices for wholesale power?

A. Recent experience has vividly demonstrated that spot markets for wholesale power can be highly volatile and are extremely difficult to forecast with confidence on either a short-term or long-term basis. As a result, any estimate of the NPV cost of buying power in the wholesale spot market is highly uncertain.

Q. But once the expected NPV cost of buying power in the wholesale market is calculated, can't it simply be used as a consistent benchmark for comparison to the expected NPV costs for the specific candidate resources that are being considered?

A. Yes, that is possible and PacifiCorp has used it in this fashion. Under this approach, the most attractive candidate resource is the one with the largest positive mark-to-market value, assuming all other things are equal. So the mark-to-market approach produces a simple metric that can easily be used to compare alternative candidate resources. However, using mark-to-market valuation to evaluate long-term resources needed to serve a utility's retail electric loads can obscure important factors that can have dramatic effects on the reliability of the results.

Q. Please explain.

A. Consider a utility whose portfolio already has sufficient resources to serve its retail electric customers' demands during the winter, but needs new resources to serve its retail electric customers' demands during the summer (e.g., PacifiCorp's East control area).

Next, suppose one candidate resource is available that will provide power on a year-round basis, while another candidate resource is available that will provide power only during the summer months. If the utility acquires the year-round resource, it will have surplus power during the winter months that must be sold. Typically, a mark-to-market calculation for the year-round resource will assume that the surplus power will be sold into the spot market (i.e., using a highly uncertain forecast of wholesale market prices).

As a result, a significant component of the mark-to-market value for the year-round resource will be based on highly uncertain revenues from surplus power sales. On the other hand, the mark-to-market calculation for the summer-only resource will be based more exclusively on costs to serve the utility's retail electric customers. As such, the value of the summer-only resource will be far more certain.

Clearly, these two candidate resources would have differing net impacts on the utility's overall electric resource portfolio. The year-round resource would create added risks associated with disposing of surplus powers during non-summer months, while the summer-only resource would avoid such risks. However, using mark-to-market values does not measure and therefore reveal such differing impacts on costs and risks for the utility's resource portfolio.

Q. Are there other ways that mark-to-market results can be misleading when used to evaluate candidate long-term resources for a load-serving utility's portfolio?

A. Yes. Mark-to-market calculations can also obscure differences in the types of costs (and resulting risks) among candidate resources. For example, suppose that a utility issues an RFP that specifies a need for base load energy, as PacifiCorp has recently done. Then suppose that it receives proposals that include one candidate resource with a cost structure that includes mostly fixed costs (i.e., capital), and another candidate resource with a cost structure that includes a larger proportion of variable costs (i.e., fuel costs such as natural gas). Clearly, costs to the utility – and ultimately to its retail electric customers – will be more certain for the capital-

intensive resource than for the resource that has a higher proportion of variable (i.e. fuel) costs. However, the mark-to-market valuation approach will produce a single metric for each candidate resource, and this important difference between the two candidate resources will be obscured. As a result, if the utility relies on mark-to-market valuations as a primary basis to evaluate the proposals it receives in response to an RFP, it could prematurely reject candidate resources that may actually better meet overall objectives for the utility's resource portfolio.

Q. Are there other types of situations where mark-to-market valuation can be more useful?

A. Yes. Mark-to-market valuation originated in the commodity and financial trading industries. It is commonly used for speculative trading purposes, including by market participants that are able to buy and sell commodities for delivery in future periods. In most commodity markets, the majority of such forward contracts are closed out in advance by market participants as they liquidate their positions before the time of delivery.

Q. What do you mean when you say that the majority of forward contracts are "closed out" by market participants before the time of delivery?

A. In most commodity markets, the volume of trading far exceeds the amount of the commodity that is actually physically delivered. In part, this reflects market participation by speculative traders who buy and sell forward contracts, but who never intend to deliver or receive the physical commodity.

For example, if a speculative trader believes that forward market prices for electricity will rise, she may purchase a forward contract today for electricity to be

delivered in August 2006. The trader will then sell the same forward contract at some time before August 2006, thereby liquidating their position. If the trader's prediction was correct and the price of the August 2006 contract was higher at the time of the sale, the trader would realize a net gain on the two trades, first a purchase then later a sale.

Q. How is the speculative trader exposed to risk?

A. Once the trader has purchased a forward contract, they become exposed to the risk that prices for the contract that they own may go down. However, the speculative trader can neutralize further exposure to risk by selling the same forward contract back into the marketplace.

Q. How do speculative traders evaluate and manage their trading portfolios?

A. Highly sophisticated methods have been developed and are commonly used to manage speculative commodity trading portfolios. These methods typically include the commodity valuation measures described above, including mark-to-market valuation and option valuation.

Q. Are the methods used to manage speculative trading activities based on any key assumptions?

A. Yes. One of the most important fundamental assumptions underlying the methods used to manage speculative commodity trading is that the trader has the unilateral discretion and the ability to quickly liquidate its trading positions.

Q. In your opinion, should a regulated utility like PacifiCorp be viewed as being similar to a speculative commodity trader?

A. No. A utility such as PacifiCorp has a fundamental responsibility to ensure that it has adequate resources available to serve the demands of its retail electric customers. In other words, the forward market purchases and sales that PacifiCorp makes are not for speculative trading purposes. Instead, PacifiCorp must maintain a portfolio of resources and use it to deliver actual physical power to its retail electric customers. Therefore, commodity trading methods that assume an entity is able to liquidate its positions are not as relevant or applicable to acquisition of long-term resources for a utility's portfolio.

Q. Are there any situations where mark-to-market valuation may be appropriate for a utility such as PacifiCorp?

A. Yes, for specific, limited purposes. Perhaps the most relevant application of mark-to-market valuation is for short-term management of imbalances in the utility's resource portfolio. For example, if a utility has a short-term surplus in its resource portfolio (e.g., due to above-normal availability of hydroelectric generation), it can be appropriate for the utility's risk management and short-term trading groups to use mark-to-market methods to value the surplus power that is available.

Q. How would you summarize your overall recommendation about that basic approach that PacifiCorp should use to evaluate specific candidate resources?

A. As I have described earlier, specific candidate resources should be evaluated in terms of their net impacts on the utility's overall resource portfolio, including cost, risk, reliability and environmental impacts. In other words, the primary focus should be on finding resources that help configure the portfolio to most effectively meet the needs of the utility's retail electric customers.

Q. You have just described various shortcomings involved with using mark-to-market valuation to evaluate candidate resources. You also noted that PacifiCorp used another commodity valuation measure, namely option values. Do the same kinds of concerns also apply regarding use of option values?

A. Yes. Option values are also dependent on highly uncertain forecasts of future spot market prices and other assumptions (e.g., spot price volatilities). Option values also provide single-dimension metrics that obscure important differences between specific candidate resources.

Q. Is there an additional disadvantage associated with using option values to evaluate candidate resources for a utility's portfolio?

A. Yes. A further disadvantage has to do with the fact that the market value of an option drops toward zero as the time of delivery approaches. Typically, a utility needs resources that provide dispatchability or other forms of optionality in order to handle fluctuations in its overall portfolio of resources, as well as fluctuations in its retail electric loads. Therefore, the utility generally must reserve such resources and keep them available until it knows whether or not it will need to use them to serve its retail electric customers' needs. As a result, the market value of the resource's optionality may rise and fall any number of times leading up to the time of delivery. However, since the utility must hold the option in reserve, it does not have an opportunity to sell it and capture its market value. In other words, the *cost* of dispatchability or other forms of optionality required to serve the needs of PacifiCorp's retail customers is far more relevant than estimates of market values that are largely unrealizable.

IV. PACIFICORP HAS NOT DEMONSTRATED THAT ITS REQUEST TO IMPLEMENT THE REVISED PROTOCOL WOULD ACCURATELY ALLOCATE POWER COSTS TO ITS CUSTOMERS IN WASHINGTON STATE

Q. Please identify the topics you address in the second part of your testimony.

A. In this section of my testimony, I will:

1. Briefly describe the Revised Protocol method that PacifiCorp proposes to use to allocate its power costs to Washington State,
2. Identify and discuss a number of reasons why the Revised Protocol would not produce an accurate allocation of power costs to Washington State, and
3. Outline a more suitable method for allocating PacifiCorp's power costs, based on a recognition that the company essentially uses two distinct portfolios of electric resources to serve its retail customers in two separate geographic regions.

Q. What method does PacifiCorp propose to use in this General Rate Case to allocate its costs to its retail electric customers in Washington State?

A. In his pre-filed direct testimony, Donald N. Furman states that PacifiCorp proposes "The Revised Protocol method of allocating PacifiCorp's costs among its state jurisdictions." Exhibit No. ____ (DNF-1T, p. 19)

Q. Has the Commission previously authorized use of the Revised Protocol on an on-going basis to allocate PacifiCorp's costs to its customers in Washington State?

A. No.

Q. Does Mr. Furman's testimony describe the Revised Protocol method of allocating costs among the various states that PacifiCorp serves?

A. Yes. For example, Mr. Furman's testimony states: "Where possible, the Revised Protocol assigns costs to the state that is directly responsible for them. Costs of distribution facilities and certain state-mandated programs are assigned in this way. The majority of PacifiCorp's costs are not, however, directly caused by any particular state. In those cases, costs are allocated based on a state's share of system energy, peak demand, and other factors." Exhibit No. ____ (DNF-1T, p. 25)

Q. Does Mr. Furman's testimony also describe how the Revised Protocol method was developed?

A. Yes. Mr. Furman's pre-filed direct testimony states: "The Revised Protocol is the result of extensive discussions lasting several years and involving parties from the various states. This process was called the Multi-State Process, or MSP." Exhibit No. ____ (DNF-1T, p.26)

Q. Has the MSP been concluded?

A. No, further discussions are continuing in the MSP. The Revised Protocol calls for the continued study of load growth effects on cost shifts between states and the development of a Structural Protection Mechanism (Revised Protocol page 7-8.)

Q. Have there also been more specific discussions about allocation of PacifiCorp's costs to Washington State?

A. Yes. Following the Commission's Order No. 06 in Docket No. UE-032065, representatives of PacifiCorp, Commission Staff, Public Counsel and Industrial Customers of Northwest Utilities engaged in discussions about inter-jurisdictional cost allocations. These discussions began in December 2004 and continued into 2005. Meanwhile, the broader MSP has continued, including discussions by

representatives of PacifiCorp and parties from various states that PacifiCorp serves. Studies of several inter-jurisdictional cost allocation methods have been performed, including the Revised Protocol and an alternative called the "Hybrid Method". These studies have been performed using PacifiCorp's "GRID" model.

Q. Was an agreement reached in the discussions about allocation of PacifiCorp's costs to Washington State?

A. No.

Q. Have you personally participated in the MSP or the Washington State discussions?

A. No.

Q. Have you reviewed records of the discussions?

A. I have reviewed selected documents from the discussions of inter-jurisdictional cost allocation. However, I have not performed an extensive review.

Q. Have you examined the GRID model that PacifiCorp has developed?

A. I have briefly reviewed portions of the documentation for the GRID model. I have not directly used the model itself.

Q. Does your testimony on inter-jurisdictional cost allocation require in-depth technical knowledge of the MSP or PacifiCorp's GRID model?

A. No. The following portion of my testimony is based on the fundamental characteristics of PacifiCorp's electric resources, the retail loads it serves and the transmission linkages between PacifiCorp's Eastern control area and its Western control area. The following portion of my testimony is also based on certain key

assumptions that I understand were used to develop the Revised Protocol and that have been included in the GRID model studies.

Q. Can you briefly summarize the basic conceptual approach that the Revised Protocol uses to allocate PacifiCorp's power costs to individual states?

A. At a very high level, the Revised Protocol divides PacifiCorp's power costs into the two categories identified in Mr. Furman's pre-filed direct testimony. The first category includes costs that PacifiCorp considers "possible" to allocate to each "state that is directly responsible for them". The second category includes power costs that are aggregated together from across PacifiCorp's entire system. The aggregated power costs are then allocated to individual states based on factors such as each state's proportional share of total system peak demand and energy.

Q. Do you believe that the Revised Protocol accurately allocates power supply costs to the portions of PacifiCorp's multi-state service area that cause those costs?

A. No, I do not. The Revised Protocol aggregates power costs throughout all geographic areas of PacifiCorp's system into a single pool and then allocates those costs to states using a method that (1) is founded on a restrictive fundamental assumption, (2) involves complex calculations that obscure other questionable assumptions, and (3) applies allocation factors to spread an unnecessarily large proportion of PacifiCorp's total power costs across states that do not create the costs, including Washington State.

Q. What restrictive fundamental assumption is the Revised Protocol method based upon?

A. The Revised Protocol method assumes that PacifiCorp's power costs can only be separated into two basic categories – costs that can be directly assigned to specific states and (all other) costs that must be aggregated together and then allocated using allocation factors. This assumption is overly restrictive and does not reflect the actual characteristics of the PacifiCorp system.

Q. Please explain.

A. The Revised Protocol method basically assumes that PacifiCorp uses a single, unified portfolio of electric resources to serve its customers' needs on a system-wide basis. However, PacifiCorp actually uses what are essentially two distinct portfolios of resources to serve two different types of loads in two geographic regions.

Q. Why is this characteristic of PacifiCorp's system important?

A. As a general ratemaking principle, if the *types* and *causes* of costs that a utility incurs to provide retail electric service vary significantly, then each *type* of cost should be allocated to the customers who *cause* it, rather than aggregating the different types of costs together. However, rather than recognizing that PacifiCorp's resource portfolios have different types and causes of costs, the Revised Protocol method aggregates costs across both portfolios and then uses allocation factors to assign them to each state.

Q. You have described PacifiCorp as essentially having two distinct portfolios of electric resources. Can you describe the two portfolios?

A. Yes, in general terms. For the most part, one portfolio includes PacifiCorp's resources and retail electric customers located in its Western control area. This

portfolio includes the portions of PacifiCorp's system and the customers it serves in Washington, Oregon and California. It also includes PacifiCorp's share of the Jim Bridger power plant in Wyoming, which is part of PacifiCorp's Western control area. Let's call this Portfolio "P". The other portfolio basically includes PacifiCorp's resources and retail electric loads located in its Eastern control area. This portfolio includes the portions of PacifiCorp's system and the customers it serves in Utah and Idaho. Let's call this Portfolio "U".

Q. What about the portion of PacifiCorp's system and the customers it serves in Wyoming?

A. Prior to the merger that formed PacifiCorp, electric resources and retail loads located in Wyoming were part of Pacific Power & Light. With the exception of Wyoming, the other remaining portions of the Pacific Power & Light system are now within PacifiCorp's Western control area. However, after the merger, loads and most resources (e.g., except the Jim Bridger power plant) in Wyoming became part of PacifiCorp's Eastern control area. As a result, it may be reasonable to include Wyoming in Portfolio "P" or Portfolio "U", or perhaps include certain parts of it in both. The following portion of my testimony recognizes that the Jim Bridger power plant is part of the Western control area.

Q. Do you have a specific view about how Wyoming loads and resources should be recognized in the two resource portfolios that you have identified?

A. Not at this time. Resolving that question involves particulars that extend beyond the scope and level of detail of my testimony. Rather, the purpose of this section of my testimony is to describe the basic characteristics of PacifiCorp's electric

resource portfolios, and to propose an overall approach that can be used to more accurately allocate PacifiCorp's power costs to Washington State.

Q. Do the types and causes of PacifiCorp's power costs differ between its two portfolios of electric resources?

A. Yes. The differences include the following:

1. Retail electric loads (including customers in Washington State) served by Portfolio "P" are generally highest during the winter months, while retail electric loads served by Portfolio "U" are generally highest during the summer months.
2. A large majority of the existing resources in Portfolio "P" were acquired to serve loads in Portfolio "P", and a large majority of the existing resources in Portfolio "U" were acquired to serve loads in Portfolio "U".
3. New resources that PacifiCorp has recently acquired and plans to acquire in the near future are being located in close proximity to retail electric loads within each corresponding portfolio. For example, new peaking and base load generating resources that PacifiCorp recently added in Utah are needed to serve load growth in that state. In other words, the new resources in Utah and the loads they are being acquired to serve are both part of Portfolio "U".

Q. Hasn't PacifiCorp claimed that it uses a single, integrated portfolio of electric resources to serve all of its retail customers on a system-wide basis?

A. Yes, they have made that claim. However, for the purposes of allocating PacifiCorp's power costs, this statement is somewhat of an exaggeration. It does not recognize the fundamental differences between loads and resources in the two

portfolios described above. In addition, it does not recognize the physical characteristics and limitations of PacifiCorp's system that effectively separate the two resource portfolios.

Q. Can you provide an example of a physical characteristic of PacifiCorp's system that limits the use of PacifiCorp's resources as a single, fully integrated resource portfolio?

A. Yes. One basic characteristic is that PacifiCorp operates two separate control areas for its system. The Western control area includes PacifiCorp resources located in Washington, Oregon and California plus the Jim Bridger power plant in Wyoming, and the retail electric loads the company serves in Washington, Oregon and California. The Eastern control area includes PacifiCorp resources located in Utah, Idaho and Wyoming (except Jim Bridger), and the retail electric loads the company serves in those states.

Q. Does PacifiCorp have the ability to transfer power between its Eastern and Western control areas?

A. Yes. However, the amount of firm transmission capacity between the two control areas is limited. The direct pre-filed testimony of Gregory N. Duvall indicates that the maximum amount of transfer capability from East to West is 546 megawatts, and the maximum amount of transfer capability from West to East is 971 megawatts (net of 100 megawatts reserved for spinning reserves and 100 megawatts reserved for non-spinning reserves). Exhibit No. ____ (GND-1T pp. 5-6)

Q. Is all of the 546 megawatt maximum amount of transfer capability from PacifiCorp's Eastern control area to its Western control area available to help meet peak loads in the Western control area, including in Washington?

A. No. Mr. Duvall's pre-filed direct testimony includes an exhibit showing that 350 megawatts of the 546 megawatts is available during off-peak periods (i.e., light load hours), but not available during on-peak periods (i.e., heavy load hours). Exhibit No. ____ (GND-1T, Exhibit 2) This factor alone reduces the amount of transfer capability from the Eastern control area to meet peak loads in the Western control area to 196 megawatts.

Q. How does the remaining 196 megawatt amount of transfer capability from PacifiCorp's East control area to serve peak loads in its West control area compare with the company's retail electric peak loads in its West control area?

A. PacifiCorp's latest Integrated Resource Plan[1] shows peak retail electric loads of 4,288 megawatts for the West control area during fiscal year 2006. Therefore the 196 megawatts of peak transfer capability from east to west represents 4.6 percent of forecasted 2006 peak load in PacifiCorp's West control area. Put another way, PacifiCorp's Portfolio "U" can be planned upon to meet a maximum of roughly one-twentieth of the total peak retail load served by Portfolio "P".

Q. Is all of the 971 megawatt maximum amount of firm transfer capability from PacifiCorp's Western control area to its Eastern control area available more than one day in advance?

[1] (PacifiCorp 2004 IRP, Appendix C, p. 30).

A. No. Mr. Duvall's pre-filed direct testimony states that 441 megawatts of the 971 megawatt maximum amount is only available on a day-ahead firm basis. Exhibit No. ____ (GND-1T, p.5)

Q. Is transmission capacity that is only available on a day-ahead firm basis included when planning a utility's portfolio of resources to meet its retail electric customers' peak load requirements?

A. No. This would be an unsound approach to integrated resource planning and would violate reliability requirements. Therefore, the 441 megawatt amount should be deducted from the 971 megawatt amount. This reduces the mount of transfer capability from PacifiCorp's Western control area that can be planned upon to serve peak loads in its Eastern control area to 530 megawatts.

Q. How does the remaining 530 megawatt amount of planned transfer capability from PacifiCorp's Western control area to serve peak loads in its Eastern control area compare with the company's retail electric loads in its Eastern control area?

A. PacifiCorp's latest Integrated Resource Plan shows peak retail electric loads of 5,910 megawatts for the Eastern control area during fiscal year 2006.[2] This means that 530 megawatts of planned transfer capability from West to East represents 9.0 percent of forecasted 2006 peak load in PacifiCorp's Eastern control area. Put another way, PacifiCorp's Portfolio "P" can be planned upon to meet less than one tenth of the total peak retail load served by Portfolio "U".

[2](PacifiCorp 2004 IRP, Appendix C, p. 30).

Q. Was any of PacifiCorp's existing transfer capability between what are now its Western and Eastern control areas available prior to the merger?

A. Yes. For example, the Jim Bridger power plant in Wyoming was part of Pacific Power & Light's system prior to the merger with Utah Power. Pacific Power & Light held firm transmission capacity to move power from Jim Bridger to serve its retail electric customers' loads in Washington and Oregon. Today, Jim Bridger remains in what is now PacifiCorp's Western control area. The rest of PacifiCorp's Wyoming power supplies and its retail customer loads in Wyoming are included in what is now PacifiCorp's Eastern control area.

Q. What is the significance of this?

A. This example illustrates that a portion of the existing firm transfer capability between what are now PacifiCorp's Western and Eastern control areas was already controlled by Pacific Power & Light prior to the merger with Utah Power. In other words, portions of the existing transfer capability between the two control areas has been available for use to serve customers in Washington State since well before the merger that created PacifiCorp. Further, Pacific Power & Light previously used those portions of the transfer capability to provide the kinds of system integration benefits that PacifiCorp describes as having been made possible by its "unified" portfolio of resources.

Q. Does adding new power supply resources to Portfolio "U" (e.g., in Utah) automatically increase the amount of peak load that can be met in PacifiCorp's West control area (e.g., in Washington)?

A. Not to any significant degree. As described above, the amount of transfer capability from the Eastern control area to the Western control area is comparatively small. In addition, PacifiCorp has existing resources in Portfolio "U" that it already uses to transfer power from its East control area to its West control area. At most, new resources added to Portfolio "U" would only displace existing resources from Portfolio "U" that are already being used in this way.

Q. Does adding new power supply resources to Portfolio "P" (to serve load growth in Washington) automatically increase the amount of peak load that can be met in PacifiCorp's Eastern control area (e.g., in Utah)?

A. Not to any significant degree. As described above, the amount of transfer capability from the Western control area to the Eastern control areas is comparatively small. In addition, PacifiCorp has existing resources in Portfolio "P" that it already uses to generate power to transfer from its Western control area to its Eastern control area. At most, new resources added to Portfolio "P" would only displace existing resources from Portfolio "P" that are already being used in this way.

Q. Has new long-term firm transfer capability between PacifiCorp's Eastern control area and its Western control area been added since the merger?

A. No, I do not believe that a significant amount has been added.

Q. Can you please summarize your conclusions regarding how the physical characteristics and limitations of PacifiCorp's system effectively separate its two resource portfolios?

A. My conclusions about this topic include:

1. PacifiCorp operates two separate control areas that largely correspond to the company's two resource portfolios and the electrically isolated retail electric loads that each serves.
2. Firm transfer capability from PacifiCorp's Eastern control area is only available to meet about 4.6 percent of forecasted 2006 retail customer peak load in its Western control area. Firm transfer capability from PacifiCorp's Western control area is only available to meet about 9.0 percent of forecasted 2006 retail customer peak load in its Eastern control area.
3. A significant proportion of the usable, long-term firm transfer capability between what is now PacifiCorp's Western control area and its Eastern control area was already held by Pacific Power & Light prior to the merger with Utah Power.
4. The amount of long-term firm transfer capability between the two control areas was not significantly increased by the merger and has not been significantly increased since the merger.
5. Addition of new electric generating resources to Portfolio "P" does not materially increase the ability of Portfolio "P" to serve the peak needs of Portfolio "U". For example, adding new generation in Washington State does not materially increase PacifiCorp's ability to deliver power to its retail customers in Utah. Similarly, addition of new electric generating resources to Portfolio "U" does not materially increase the ability of Portfolio "U" to serve the peak needs of Portfolio "P". For example, adding new generation in Utah

does not materially increase PacifiCorp's ability to deliver power to its retail customers in Washington State.

Q. Near the beginning of this section of your testimony, you stated that the Revised Protocol method involves complex calculations. Please explain.

A. The Revised Protocol assumes that PacifiCorp has a single, unified portfolio of resources. As a result, the Revised Protocol lumps most of PacifiCorp's power costs, including costs for many resources from both portfolios, together before attempting to allocate them back to individual states. PacifiCorp has developed a highly elaborate model, known as the GRID model, to perform these calculations.

Q. Is use of an elaborate or complex model to allocate power costs undesirable?

A. Not necessarily. Added complexity may be justified when it produces greater accuracy and more reliable results. However, one of the risks created by adding unnecessary complexity is that key assumptions can be obscured within the model, and the impacts of those assumptions can also be obscured.

Q. Can you provide any examples of key assumptions that you believe have been embedded within the GRID model?

A. Yes. First, as I have mentioned, the GRID model begins with the fundamental, yet exaggerated, assumption that electric resources throughout PacifiCorp's entire system are part of a single integrated portfolio, and that costs for those resources must be aggregated together. However, other assumptions that are less obvious but produce significant impacts have also been included in the GRID model. Some of these assumptions expose retail electric customers in Washington State to costs and

risks associated with new resources that PacifiCorp is acquiring to serve load growth in other parts of its multi-state system.

Q. Please provide an example.

A. I can illustrate this using one of the new resources that PacifiCorp recently added to meet growing energy loads in its Portfolio "U", namely the Currant Creek Project in Utah. Currant Creek is a 525 megawatt combined-cycle combustion turbine project, fueled by natural gas. The Revised Protocol method assumes that costs for Currant Creek, including fuel costs, are rolled into the pot of power costs that are then spread across all of the states in PacifiCorp's system, including Washington.

Market prices for natural gas have recently risen dramatically, significantly increasing fuel costs for the Currant Creek project. For example, PacifiCorp's 2003 IRP used a forecast of natural gas prices that showed an annual average price in Utah during 2006 of $3.82 per MMBtu (PacifiCorp 2003 IRP Report, Appendix C, p.198). Assuming Currant Creek is operated as a mid-range generating facility with a 65 percent annual capacity factor and it uses an average of 7.2 MMBtu of natural gas to produce 1 megawatt-hour of electricity, the annual cost of natural gas for the project during 2006 was expected as of 2003 to be roughly $82.2 million. On October 27, 2005, settlement prices on the New York Mercantile Exchange (NYMEX) for natural gas futures for calendar year 2006 were $11.34 per MMBtu. After allowing for a geographic basis differential between the NYMEX Henry Hub and Utah delivery points, a conservatively low estimate for the cost of natural gas for the Currant Creek project during 2006 is now expected to be roughly $10.00 per MMBtu. This raises the expected cost of natural gas for Currant Creek during 2006

to $215.2 million in 2006. In other words, during the last couple of years, the expected cost of power during 2006 from just the Currant Creek Project has *increased* by about $133 million. This $133 million increase in expected annual fuel costs for the Currant Creek resource – alone – compares with system net power costs of $830 million proposed in PacifiCorp's filing.

This example (increased fuel costs for just one of the new resources PacifiCorp has recently added to serve its loads in Utah) illustrates how key assumptions embedded in the Revised Protocol can have large impacts on the allocation of PacifiCorp's power costs to Washington State.

Q. Are you aware of other concerns that have been identified regarding the assumptions and analysis used for the Revised Protocol?

A. Public Counsel witness Merton R. Lott describes a number of additional complexities and other concerns regarding the Revised Protocol method in his direct testimony. It is my understanding both commission staff and ICNU will File testimony identifying additional concerns with Revised Protocol

Q. Is a more accurate and straightforward method available for allocating power costs to Washington State?

A. Yes. In very simple terms, the method involves three basic steps. First, the method takes power costs that the Revised Protocol method aggregates together on a system-wide basis and instead assigns those costs to the two separate Portfolios "P" and "U" that I described earlier.

Second, the method allocates power costs from Portfolio "P" to Washington State and to the other portions of PacifiCorp's system that Portfolio "P" serves on a primary basis.

Third, the method calculates power costs to Washington State by adding (a) power costs that were allocated to Washington from Portfolio "P" and (b) power costs if any that are designated as Washington-specific.

Q. Under this alternative method, could transfers of power between Portfolio "P" and Portfolio "U" be recognized?

A. Yes. It is my understanding that several potential methods for recognizing and valuing inter-portfolio transfers of power have been identified during discussions on development of a Hybrid Method ordered by the Oregon Commission.

Q. Would use of this method for allocating power costs interfere with PacifiCorp's ability to realize efficiency gains from operating its overall system on an integrated basis?

A. No. PacifiCorp could continue to operate all of its electric resources and its system as is currently does.

Q. Has PacifiCorp provided the results of studies with the GRID model to allocate costs under the alternative method that you have described?

A. Not to my knowledge.

Q. Have you performed an analysis using the GRID model to allocate costs according to the method you recommend?

A. No. It is PacifiCorp's responsibility to demonstrate that its proposed method for allocating costs to customers in Washington State produces rates that are fair just

and reasonable. In my testimony above, I have described how the Revised Protocol method does not accurately allocate power costs to Washington State. I have also suggested that a more straightforward method should be used, one that I believe will more accurately allocate power costs to Washington State. In particular, the portfolio-based method I have outlined offers a more straightforward method for matching the *types* and *causes* of power costs for PacifiCorp's Portfolio "P".

Q. Do you have any recommendations about how the portfolio-based method you have described could be developed and evaluated?

A. One approach would be for PacifiCorp, Commission Staff, Public Counsel and other parties to commit to a good faith effort to more fully develop and evaluate a portfolio-based method for allocating PacifiCorp's power costs to Washington State. Perhaps the GRID model could be modified and used to support this effort.

Q. Would it be essential for parties representing each of the states that PacifiCorp serves to participate in this effort?

A. No, although parties representing one or more states, including those served from PacifiCorp's Portfolio "P" may wish to participate. If representatives of another state oppose considering a portfolio-based method as an alternative to the rolled-in, system-wide power cost assignment approach employed by the Revised Protocol method, then a Portfolio "P"-based method could be developed and used for Washington and any other states that find it to be a more accurate method. The primary concern for Washington State on this matter is that an accurate method be used to allocate PacifiCorp's power costs to Washington State.

V. PACIFICORP'S RESOURCE DECISION-MAKING PROCESSES MUST BE ADDRESSED AND INCENTIVES OF EMPLOYEES INVOLVED IN THOSE PROCESSES MUST BE PROPERLY ALIGNED BEFORE IMPLEMENTING A POWER COST ADJUSTMENT MECHANISM (PCAM) FOR PACIFICORP

Q. Why is PacifiCorp proposing a PCAM?

A. The direct pre-filed testimony of Donald R. Furman states that "PacifiCorp proposes: A new Power cost Adjustment Mechanism (PCAM) to deal with volatility in power costs" Exhibit No. ____ (DNF-1T, p. 19). Mr. Furman's testimony also claims that "Power cost volatility is largely outside the Company's control" Exhibit No. ____ (DNF-1T, p. 21).

Q. Do you agree that power cost volatility is largely outside PacifiCorp's ability to control?

A. I agree that the *prices* at which PacifiCorp buys and sells power in the wholesale market are (and should be) beyond its ability to control. However, I do not agree that variability in power *costs* is largely beyond PacifiCorp's ability to control.

Q. Please explain why you have distinguished between volatility in wholesale market prices for power and variability in PacifiCorp's power costs.

A. Simply put, price multiplied by quantity equals cost. Volatility in wholesale market prices for power is one factor that can contribute to variability in PacifiCorp's power costs. However, the *quantity* of power that PacifiCorp buys and sells at market prices is another factor that drives variability of its net power costs. PacifiCorp has within its control the ability to limit variability in its net power costs by limiting the quantity of power it needs to buy and sell, even though (and especially when) wholesale market prices for power may be volatile.

Q. Earlier, in the first and second sections of your testimony, you stated that in its evaluations of candidate resources, PacifiCorp should analyze net impacts on cost, risk, environmental impacts or other objectives for the company's overall resource portfolio. You also noted that PacifiCorp incorporates similar objectives in its IRP analyses. Is limiting variability in net power costs related to any of those objectives?

A. Yes. Limiting variability in PacifiCorp's net power costs is a key component of the objective of managing of risk for its resource portfolio.

Q. Can PacifiCorp limit the quantity of power that it must buy and sell at wholesale market prices, and if so, how?

A. Yes it can, to a significant extent. Several processes are available for use by utilities like PacifiCorp to help them make decisions and take actions to control variability in the quantity of power that they must buy and sell at volatile wholesale market prices. These processes include the following:

1. Integrated Resource Planning (IRP),
2. Long-term resource acquisition, and
3. Energy risk management.

Q. How can Integrated Resource Planning help PacifiCorp make decisions that limit the quantity of power it must buy and sell at volatile wholesale market prices?

A. An IRP process can be used to address resource adequacy, including the question of what quantity of firm, long-term resources the utility should include in its electric

resource portfolio. Once a resource adequacy standard has been selected, a long-term resource strategy is developed to meet the standard.

For example, in its 2003 IRP, PacifiCorp selected a resource adequacy standard that limits the extent to which the company plans to make short-term market purchases to serve its retail electric customers' needs. PacifiCorp then used the resource adequacy standard as a basis for developing a resource strategy that relies mainly on long-term electric resources. PacifiCorp reached similar conclusions in its 2004 IRP.

Q. Please provide another example to illustrate how an IRP can help a utility make decisions that limit its need to buy and sell power at volatile wholesale market prices.

A. An IRP can also be used to evaluate how adding different types of electric resources would affect overall portfolio performance, including risks associated with short-term purchases and sales of wholesale power at market prices. For instance, if a particular type of resource such as hydroelectric generation already makes up the majority of the utility's portfolio, an IRP can help the utility identify other types of long-term resources that limit the need to buy or sell power in the wholesale market when output from its existing hydro resources varies.

Q. The second process you identified above is long-term resource acquisition. How can resource acquisition decisions limit the quantity of power PacifiCorp will need to buy and sell at volatile market prices?

A. When evaluating resource acquisition opportunities, PacifiCorp can assess how different candidate resources would affect its resource portfolio, including impacts

on quantities of market purchases and sales of power. For example, if PacifiCorp acquires a year-round resource to meet a need that only exists during one season (e.g., winter), then the amount of surplus power that it must sell during the rest of the year is increased. In this situation, a winter-only resource would better enable PacifiCorp to limit its need to sell surplus power. In the first part of my testimony, I describe other advantages of evaluating new resource candidates in terms of their impacts on the utility's overall resource portfolio.

Q. Please describe how the third process, energy risk management, can help limit PacifiCorp's need to purchase and sell power at volatile wholesale market prices.

A. The Energy risk management processes looks forward with a short-term perspective typically of one or two years. It includes three components: 1) evaluation of portfolio positions (e.g., *expected* surpluses and/or deficits); 2) portfolio risk exposures (e.g., potential *variability* in surpluses and deficits) and 3) portfolio hedging strategies (e.g., forward power purchases to fill deficits) from more of a short-term perspective, typically looking forward over the next one to two years. A useful way to view this process is that it starts with the portfolio that has been configured in the IRP and resource acquisition processes, and then helps manage use of that portfolio for actual service to the utility's retail electric customers. Most utilities use rigorous energy risk management processes that help them limit their need to purchase and sell power at volatile wholesale market prices.

Q. Are energy risk management techniques used to limit the impacts of other factors besides volatile wholesale market prices for power?

A. Yes. Energy risk management can also help the utility use its portfolio of electric resources to respond to variability in its retail electric customers' loads (e.g., due to fluctuating temperatures), variability in output from its generating resources (e.g., due to hydroelectric conditions or unplanned outages), and volatility in short-term market prices for fuels (e.g., natural gas) used in its generating facilities.

Q. Do PacifiCorp's witnesses identify these types of factors?

A. Yes. The pre-filed direct testimony of Mark T. Widmer identifies several similar factors and suggests that they cause variability in PacifiCorp's net power costs (NPC), "Deviations from NPC in rates are primarily related to factors not controllable by the Company. For example, hydro conditions, weather conditions, wholesale market prices for natural gas and electricity and the timing of forced outages are not controllable." Exhibit No. ____ (MTW-1T, p. 30)

Q. If PacifiCorp cannot control fluctuations in factors such as hydroelectric conditions, does that mean that it also has no ability to limit the impacts of fluctuating hydro conditions on its power costs?

A. Testimony by PacifiCorp's witnesses could easily be interpreted as leading to that conclusion. However, such a conclusion would be incorrect. For example, while I agree that PacifiCorp cannot control how much water will be available for hydroelectric generation in a given year, I do not agree that PacifiCorp has no ability to limit negative impacts of lower than normal hydro conditions.

Q. Do PacifiCorp's witnesses identify and describe the three processes that you have identified as being available to limit variability in the company's net power costs?

A. Not in any significant detail. Instead, several PacifiCorp witnesses reiterate the claim that power costs are largely beyond the company's ability to control. As a result, PacifiCorp's ability to control variability in its power costs is under-emphasized and the expected degree of variability in power costs is over-stated.

Q. How is the preceding discussion related to PacifiCorp's proposed PCAM?

A. The preceding portion of my testimony is relevant for two reasons:

1. It demonstrates that the company has under-stated its ability to limit variability in its net power costs, and
2. It identifies three key resource decision-making processes – IRP, resource acquisition and energy risk management – that should be addressed before implementing a PCAM.

Q. Why should these processes be addressed before implementing a PCAM?

A. IRP, resource acquisition and energy risk management represent three key processes that PacifiCorp can use to meet the needs of its retail electric customers, including limiting variability in its net power costs. If PacifiCorp performs these processes well, its net power costs will be less variable and the dollar amounts that would need to flow through the PCAM mechanism will be reduced. Therefore, prior to implementing a PCAM, these processes should be addressed to ensure that PacifiCorp's resource decision-making properly limits variability in its net power costs.

Q. Does PacifiCorp's proposed allocation of variances in its net power costs have any bearing on the need to address its resource decision-making processes?

A. Yes. PacifiCorp, proposes to allocate 90 percent of increases or decreases in its net power costs to its retail electric customers in Washington State, and allocate the remaining 10 percent to company shareholders. In other words, customers would assume a large majority of the risk associated with variability in PacifiCorp's net power costs.

Q. Can you make any observations about how effectively PacifiCorp has been using each of the three resource decision-making processes to limit variability in its net power costs?

A. In its recent IRP processes, PacifiCorp has performed fairly extensive and rigorous analyses of risks, particularly the risk of variability in costs for its overall resource portfolio. So PacifiCorp has been doing good work on this topic in its recent IRPs. By comparison, the process that PacifiCorp has been using to acquire new long-term resources falls far short of adequately addressing impacts of candidate resources on the company's overall resource portfolio, including variability in net power costs. Therefore, more attention and improvement is needed to long-term resource acquisition than to IRP. Direct testimony by PacifiCorp witnesses provides little information that can be used to determine how well its energy risk management process is functioning to limit variability in net power costs. Significantly more information about PacifiCorp's energy risk management process is needed to determine whether it is adequately limiting variability in the company's net power costs.

Q. How do you recommend that PacifiCorp's resource decision-making processes be addressed?

A. First, PacifiCorp should more clearly acknowledge that it has a fundamental responsibility to limit variability in its net power costs.

Second, PacifiCorp should demonstrate how its IRP, resource acquisition and energy risk management processes are designed to meet the needs of the company's retail electric customers, including limiting excessive variability in its net power costs.

Finally, PacifiCorp's resource decisions should be made more transparent, including subjecting them to external review and scrutiny to verify that proper consideration was given to meeting customer needs, including limiting variability in the company's net power costs.

Q. Can you provide a specific example of a topic that should be addressed?

A. Yes. Allocating 90 percent of variances in PacifiCorp's net power costs to retail electric customers would cause them to bear by far the largest share of the consequences of PacifiCorp's energy risk management decisions. Therefore, the policies and practices that PacifiCorp uses for its energy risk management and short-term energy trading activities will need to be modified to explicitly meet the needs and interests of the company's retail electric customers.

Q. Why do the incentives of employees involved in PacifiCorp's energy resource decision-making need to be properly aligned?

A. Insulating PacifiCorp shareholders from 90 percent of the variability in the company's power costs may create incentives for employees to pursue resource decisions or take actions that involve unnecessarily large risks. For example, to the extent that PacifiCorp's energy risk management and trading employees stand to

receive bonuses for disposing of surplus power, those employees could naturally be interested in seeing the company acquire new resources that create or add to (e.g. seasonal) surpluses in the resource portfolio. This could lead to acquisition of new resources that (a) increase PacifiCorp's need to engage in portfolio hedging and short-term trading (and therefore create opportunities for larger employee bonuses), while (b) increasing variability in PacifiCorp's net power costs.

Q. Can anything be done to avoid conflicts of interest like this?

A. This could be dealt with in part by ensuring that the processes PacifiCorp uses to plan and acquires resources are properly focused on meeting the needs of the company's retail electric customers. This would include demonstrating that evaluation of new resource acquisition opportunities includes proper consideration of impacts on variability in PacifiCorp's net power costs.

Another step that should be taken would be to structure the incentive compensation program for employees (i.e., those involved in resource decision-making) to align their incentives with the needs and interests of PacifiCorp's retail electric customers.

Q. Does this conclude your testimony?

A. Yes.