BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

IN THE MATTER OF THE PETITION OF AVISTA CORPORATION, d/b/a AVISTA UTILITIES, FOR CONTINUATION OF THE COMPANY'S ENERGY RECOVERY MECHANISM, WITH CERTAIN MODIFICATIONS

DOCKET NO. UE-060181

DIRECT TESTIMONY OF STEVEN G. JOHNSON (SGJ-1T)

ON BEHALF OF

PUBLIC COUNSEL

APRIL 21, 2006

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I. INTRODUCTION

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

A. My name is Steven Johnson. I am employed as a Regulatory Analyst for the Public Counsel Section, Washington State Attorney General's Office. My business address is 900 4th Avenue, Suite 2000, Seattle, Washington 98164-1012.

Q. Please briefly describe your educational background and professional experience.

A. I have a Bachelor of Science Degree in Chemistry from The Evergreen State College and a Master of Public Administration from The Evans School at the University of Washington. I have been employed as a Regulatory Analyst with Public Counsel Section of the Washington State Attorney General's Office for one year. Prior to my employment with Public Counsel, I was employed at Puget Sound Energy as a Transmission Resource Analyst (merchant transmission planning) for approximately two and a half years including an internship. I have appeared before the Commission for Public Counsel in several Open Meetings and as a witness in the settlement panel for the PacifiCorp/MidAmerican merger. *In the Matter of the Joint Application of MidAmerican Energy Holdings Company and PacifiCorp, d/b/a Pacific Power & Light Company For an Order Authorizing Proposed Transaction*, Docket No. UE-051090.

Q. For whom are you testifying?

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

Q. What is the purpose of your testimony?

A. My testimony responds to the Avista filing in this docket of a request to modify its Energy Recovery Mechanism (ERM).

Q. Are there issues from the Avista rate case order that you are not addressing in this testimony?

A. Yes. In the rate case, Public Counsel had raised issues regarding the inclusion of certain common costs assigned to net production in the retail revenue credit factor and the "production property adjustment." The issues were not finally resolved in the rate case order. *WUTC v. Avista Corporation*, Docket Nos. UE-050482, UG-050483, Order No. 05, ¶¶ 78-83. I do not address either of these issues. The production property adjustment is a general rate case adjustment, because the current proceeding is not a general rate case, it is an inappropriate place to change this adjustment. However, it remains Public Counsel's position that this general rate case adjustment (production factor) is different than the retail revenue credit adjustment in the ERM. Public Counsel recognizes the two items do deal with similar issues. Thus, if and when the Commission adopts a production factor adjustment for Avista similar to that used in PSE general rate cases, then accommodations will have to be made in the ERM mechanisms to account for this fact. Such accommodations are currently included within PSE's PCA mechanism and create no difficulty in processing PSE's PCA. These are issues that are primarily related to ratemaking accounting, rather than to the design of the ERM itself, which is the focus of my testimony. While Public Counsel believes that the issues should ultimately be addressed, that review can be better conducted in the course of a full rate case.

Q. Please provide an overview of your testimony.

A. My testimony begins with a summary of my recommended changes to the ERM. I then describe the purpose and background of the ERM and review the principles a properly designed power cost adjustment mechanism (PCA) should address. Next, I review the Company's proposed changes to the ERM. Finally, in the Issues and Recommendation section, I discuss each of my recommended changes to the ERM in more detail.

II. SUMMARY OF RECOMMENDATIONS

Q. Could you please summarize your recommendations in this case?

A. I have eight recommendations:

- The deadband should be reduced from $9 million to $6 million.
- Power costs from $6 million to $12 million over the baseline would be shared 50/50 between ratepayers and the Company.
- Above $12 million the sharing band should remain 90/10 ratepayer/Company.
- All transmission costs for delivering power to Avista's system should be included in the ERM. The variable transmission costs, generally described as wheeling revenue and expense, should be included in the net power costs portion of the ERM and, correspondingly, Company-owned transmission plant costs should be included in the retail revenue credit after approval in a general rate case.
- Only the amount of new long-term power contracts that are at or below the authorized proforma net power cost should be included in the net power supply costs. Once reviewed and approved in a general rate case, the full cost of a new long-term power contract should be included in the proforma retail revenue credit of the ERM. Contracts with terms greater than 2-years should be considered long-term contracts.
- An adjustment for major thermal plant outages should be included in the ERM.
- Brokerage fees should be included in the net power cost portion of the ERM.

III. ERM PURPOSE AND REVIEW CRITERIA

Q. How was the ERM created?

A. The ERM was created by agreement in 2002 between Avista, the Commission Staff, Industrial Customers of Northwest Utilities (ICNU), and Public Counsel and approved by the Commission. *WUTC v. Avista Corporation*, Fifth Supplemental Order, Docket No. UE-011595, ¶¶ 34-40. The settling parties agreed that a review of the ERM should begin on or before December 31, 2006. *Id.,* ¶ 7.

Q. What is the purpose of the ERM?

A. The ERM was intended to allow recovery of short-term variations in net power costs beyond Avista's control or influence, within the ordinary range of variation of hydro. It was not designed to address extraordinary costs. *Id.,* ¶ 37-39.

Q. What principles should be applied in reviewing the ERM?

A. On April 17, in its final order in the PacifiCorp general rate case, the Commission reviewed the principles for establishing a properly designed power cost adjustment mechanism:

- The purpose is to recognize variability in the cost of operating *existing* power supply resources as a result of abnormal weather conditions that are out of a utility's control. Ratepayers understand the connection between weather and rates;[1]
- Power cost adjustment mechanisms are *short-run* accounting procedures to address *short-run* cost changes resulting from unusual weather;[2]
- It is not appropriate to include new resources in a power cost adjustment mechanism. New resources must be considered in general rate cases or power cost only rate cases;[3]

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[1] *WUTC v. Puget Sound Power & Light Co*., Docket U-81-41, Sixth Supplemental Order at 21-22 (Dec. 1988) (PSE ECAC*); Petition of Washington Water Power for PCA Mechanism*, Docket U-88-2363-P, First Supplemental Order Denying Petition at 8 (Sept. 1989); *WUTC v. Avista Corp.*, Dockets UE-991606 & UG-991607, Third Supplemental Order at 50, 52 (Sept. 2000).
[2] *Petition of Washington Water Power for PCA Mechanism*, Docket U-88-2363-P, First Supplemental Order Denying Petition at 8 (Sept. 1989); *WUTC v. Avista Corp.*, Dockets UE-991606 & UG-991607, Third Supplemental Order at 50, 52 (Sept. 2000).
[3] *WUTC v. Puget Sound Power & Light Co*., Docket U-81-41, Sixth Supplemental Order at 22 (Dec. 1988) (PSE ECAC).

- Ratepayers should receive the benefit of a reduction in cost of capital, as a power cost adjustment introduces rate instability for ratepayers and earnings stability for stockholders,[4] and;
- Power cost adjustment mechanisms should not interfere with least cost planning, conservation or other regulatory goals.[5] *WUTC v. PacifiCorp*, Docket Nos. UE-050684 & UE-050412, Order Nos. 03 and 04, ¶ 91. (emphasis in original) (PacifiCorp order)

In addition, the Commission endorsed the principle that:

> [P]ower cost recovery mechanisms should also apportion risk equitably between ratepayers and shareholders. In striking that balance, we consider risks allocated through the normalization process, a utility's financial condition, and other circumstances affecting a utility's ability to recover its prudent expenditures. *Deadbands and sharing bands are useful mechanisms, not only to allocate risk, but to motivate management to effectively manage or even reduce power costs.* Id., ¶ 96 (emphasis added).

I will apply these principles to the Avista ERM Proposals and demonstrate how my recommendations are consistent with these principles.

Q. Please provide a short review of the structure the ERM.

A. The ERM is intended to measure and allow partial recovery of the variability in short-run power costs beyond the utility's control induced by abnormal weather conditions. The mechanism can do this if it measures the utility's overall variability in power supply costs. The ERM tracks two different types of costs separately, (1) variable production costs , and (2) fixed production costs.

The change in variable power costs are tracked on a monthly basis by comparing the actual variable power expenses recorded in the accounts to the authorized net power cost set in a rate case. If hydro production is low due to weather the variable power

[4] *WUTC v. Puget Sound Power & Light Co*., Docket U-81-41, Sixth Supplemental Order, (Dec. 1988) at 20 (PSE ECAC); *Petition of Washington Water Power for PCA Mechanism,* Docket U-88-2363-P, First Supplemental Order Denying Petition at 8 (Sept. 1989); *WUTC v. Avista Corp.*, Dockets UE-991606 & UG-991607, Third Supplemental Order at 50, 52 (Sept. 2000).
[5] *WUTC v. Puget Sound Power & Light Co*., Docket U-81-41, Sixth Supplemental Order at 23 (Dec. 1988) (PSE ECAC).

expenses might well be higher. The amount they are above the authorized net power cost is recorded and applied to the deadband and sharing bands.

The fixed power costs are tracked in the retail revenue credit along with the variable power costs from the general rate case. These power costs are tracked on a unit cost basis. The fixed power costs are divided by the total authorized load determined in a rate case to derive a $/MW unit cost coupled with the unit cost of the variable power supply expenses from the rate case. If load is above authorized level because of weather or load growth the number of extra MW of load is multiplied by the unit cost and the dollar amount is credited toward ratepayers through the deadband and sharing band mechanism. This allows for the tracking of variable costs due to weather that are out of the utility's control and prevents the over-collection of the fixed power costs.

In this way the variability related to short term fluctuations in the total unit cost of power supply can be tracked. In such a mechanism it is essential that all variable power supply costs be included in the net power costs and all the fixed production costs be included in the retail revenue credit because absent the full inclusion of both variable and fixed costs in these calculations the ERM cannot measure whether total power supply costs are increasing or decreasing. Exclusion of fixed costs or any material portion of the fixed costs would result in an overstatement of the actual impact of an increase in the nominal variable costs.

As an explanation assume that an increased load is served by either the short-term purchase of power or increased usage of an existing power plant contracted or owned. Under this scenario, nominal variable costs would increase. Since these would most likely be at the incremental cost level the increased load would most likely increase the net variable cost on a unit basis. But as the variable embedded unit cost of power is only a portion of total power costs on a unit basis the increase in total power supply costs would be less on a unit basis or nonexistent.

IV. AVIST'S PROPOSED CHANGES TO THE ERM

Q. Please provide a review of how the ERM Mechanism tracks costs?

A. Avista has proposed elimination of the existing $9 million deadband. It would be replaced with a 90% ratepayer/ 10% Company sharing arrangement. All net power costs that exceed the ERM authorized level combined with the retail revenue credit adjustment, would be applied to the sharing band. (Exhibit No. __ (KON-IT) p. 12, ll. 6-7). Under the current deadband, Avista absorbs the first $9 million of combined costs above authorized levels and retains for shareholders the first $9 million below the authorized levels. In its proposal, Avista makes no guarantee or commitment to reduce the cost of capital in exchange for the shifting of risk to the ratepayers.

Avista's only other recommendation is the inclusion of a portion of the transmission costs. Avista witness Mr. William Johnson states, "In response to Public Counsel's concerns [in Docket No. UE-050482], the Company is proposing to add transmission revenues and expenses to the ERM." (Exhibit No. __ (WGJ-1T), p. 4, ll. 5-6). Mr. Johnson goes on to propose including transmission revenue in FERC Account 456.100 and transmission expense contained in FERC Account 565 (Exhibit No. __ (WGJ-1T), p. 4, ll. 6-8). While these accounts contain "Wheeling" revenue and expenses, he does not include the cost of Company-owned transmission rate base and associated expenses as recommended by Public Counsel Witness Mert Lott in Docket No. UE-050482, Exhibit No. 281, (MRL-1T), p. 75, ll.1-3.

V. ISSUES AND RECOMMENDATIONS

Q. What changes to the deadband and sharing bands do you propose?

A. I recommend a deadband and two sharing bands, all of which are symmetrical.

- The first $6 million above or below the net power cost (after the retail revenue credit adjustment) should be absorbed or kept, respectively, by the Company. This is a $3 million reduction of revenue at risk in the deadband.
- Additional costs between $6 million and $12 million would be shared 50/50 between the ratepayer and the Company. Likewise, reductions in costs from $6 million down to $12 million should be shared 50/50.
- Additional costs above the $12 million band would be shared 90/10 between the ratepayer and the Company while reductions in costs beyond $12 million should also be shared 90/10 between the ratepayer and the Company.

Q. Why do you recommend against Avista's proposal to eliminate the deadband?

A. As I noted above, the Commission's PacifiCorp order states that a PCA should apportion risk equitably between ratepayers and shareholders, and further observes that deadbands are useful mechanisms to do this. *Id.*, ¶ 96. The complete elimination of Avista's deadband runs afoul of this principle and puts ratepayers at risk for inadequate risk management efforts, shifting existing exogenous risk to ratepayers.

When the Company is planning to meet next year's loads it faces balancing an entire year's loads with its resources. If the Company perceives a power supply shortage or a price risk in meeting that load it should try to engage in hedging activities to mitigate that risk. But hedging activities cost money because the Company will be paying a third party to take on risk. It is important to have a significant amount of money at risk to the Company to provide an incentive to engage in mitigating the risk that the Company can have influence over. Under the Company proposal to eliminate the deadband and replace it with a 90/10 sharing band, Avista would be at risk for only $900,000 for excess cost up to $9 million, a ninety percent reduction in its current level of exposure and a corresponding increase in ratepayers' risk. The Company would only be at risk for $1.2 million for excess cost up to $12 million. This compares to an at-risk amount of $9 million for power costs of $12 million under my recommendations.[6] Compared to a total authorized net power cost of $105 million, neither $900,000 or $1.2 million is a significant amount of money[7].

Q. Are there other reasons you oppose the Company's proposal to eliminate the Deadband?

A. Yes. In his testimony, Kelly Norwood states: "Recent experience has repeatedly shown that the net power costs included in base rates have been too low, and because of the $9 million deadband, the Company is continuing to absorb $9 million per year in costs, prior to being able to defer costs for recovery." (Exhibit No. __ (KON-1T), p. 6, ll.10-12). Avista, however, agreed to this level of power costs in the recent rate case settlement to which Public Counsel was not a party. If power costs are not being set correctly they should be changed. Avista is engaging in circular logic in arguing that the deadband needs to be changed because the power costs are set incorrectly. Mr. Norwood states, "Avista agreed to natural gas prices for gas-fired generation of $7.25/MMBTU as part of the Settlement package, knowing that the forward price of natural gas at the time was greater." (Exhibit No. __ (KON-1T), p. 4, ll. 5-7). It is not appropriate for Avista to agree to setting levels for one portion of the ERM and then use that agreement, now asserted to be incorrect, to alter a different feature of the ERM which has a different function, namely, keeping the Company motivated by a risk/incentive deadband to minimize power costs. The proper approach is to set the net

[6] 100 percent of the first $6 million plus 50 percent of the next $6 million for a total of $9 million.
[7] Monthly power cost deferral report for the month of March, 2006, p. 19, l. 14.

power costs correctly in a rate case so all the features of the ERM can work in balance. Avista can address this concern in its next general rate proceeding.

Q. Are there other Company arguments for the elimination of the dead band that you disagree with?

A. Yes. Mr. Norwood's belief that Avista could achieve "increased financial stability, through elimination of the deadband…" (Exhibit No. __ (KON 1T) p. 7, l. 3) amounts to a directional bet on future hydro conditions. I strongly recommend the Commission not engage in point-of-view alterations of the ERM design based on guesses about what short-term hydro production levels will be. The assertion that reducing the deadband will allow Avista more revenue recovery and improved financial health is driven by the assumption that net power costs in the near future will be similar to the conditions which drove costs in the last three and one half years -- namely that hydro conditions will be below average. Its important to remember that the reduction in the "at risk" deadband is also a reduction in the deadband amount the Company may keep when the net power costs are below the authorized levels. Under my proposed $6 million deadband, for example, the shareholders are allowed to keep the first $6 million of reduced costs. Thus, in good hydro years, with costs below authorized levels, the elimination of the deadband could cost the Company shareholders $6 million, weakening the Company's financial condition relative to my proposal.

This is not merely theoretical. The 2006 ERM monthly reports to date indicate how hydro levels can change and alter net power costs. The March ERM monthly report has an accumulative positive (surplus) of over $5 million and Avista has indicated that hydro levels are above normal for the October 05 - October 06 water year.[8] Mr. Norwood states, "Repeatedly absorbing the $9 million deadband every year

[8] Monthly power cost deferral report for the month of March, 2006, p. 19, l. 14; Avista's Response to ICNU's Data Request No. 1.22.

is undermining the Company's ability to regain its financial health." (Exhibit No. __ (KON-1T), p. 6 l.16-17). The glimpse into year 2006 provided by the 2006 ERM Monthly reports should remind Commission that the last three and one half years of experience with the ERM may not necessarily be predictive. The Commission has approved a 50 year stream flow data average for establishing hydro normalization[9]. Altering the sharing bands based on a short-term view of hydro production would be an ineffective and inappropriate way to attempt to bolster Avista's financial health or balance risks between ratepayers and Avista.

Q. How did you arrive at the $6 million deadband and the 50/50 sharing band?

A. I compared PSE's return on ratebase that is at risk in PSE's PCA sharing bands with Avista's return on ratebase that is at risk in Avista's ERM sharing bands--scaled in proportion to the size of each Company's respective ratebase.

Q. Why did you use PSE's PCA sharing band as a comparison?

A. Public Counsel was a party to the settlement that created the PSE PCA. Public Counsel views the PSE PCA as a reasonably designed PCA with an equitable apportionment of risk. While Avista and PSE are not identical companies, the risk apportionment in the PSE PCA does provide an example of a reasonable sharing of risk against which to measure other proposals.

Q. Please explain how the comparison was done?

A. To scale Avista's sharing bands to PSE's sharing bands, I divided Avista's total rate base by PSE's total rate base and then multiplied PSE's sharing bands by that ratio. On this basis, Avista's deadband would be $6 million. As noted, the 50/50 band comparable to PSE in Avista's case is for costs from $6 million to $12 million. Finally, the comparable level for Avista for the 90/10 sharing is for costs above $12 million.

[9] *WUTC v. Avista Corporation*, Docket Nos. UE-050682 & UG-050483, Order No. 05, ¶¶ 118-126. *WUTC v PSE*, Docket UE-040640 & UE-040641, Order No. 6.

Q. Is it possible to evaluate the comparable impact of these sharing bands in terms of the Company's return?

A. Yes. The effect on the equity return for a $6 million deadband would be a 1.2 percentage point reduction in the *allowed* return on equity. Because of the scaling to PSE's ratebase, it is the same as the allowed return on equity at risk in PSE's sharing bands. This would reduce the allowed return to 9.2% from 10.4%. By comparison Avista's proposal to replace the deadband with a 90/10 sharing band puts only .12 percentage points of their allowed return on equity at risk through the $6 million range. This only reduces the allowed return on equity to 10.28% from 10.4%. In Avista's proposal, Avista's return on rate base at risk is .12 percentage points or one-tenth the return on ratebase at risk faced by PSE (1.2) and one-tenth the return on ratebase at risk in my recommended deadband for Avista.

If excess power costs reach $12 million, under Avista's proposal there is still only a .24 percentage point change in equity return. This only reduces the allowed return from 10.4% to 10.16%. The return on ratebase at risk in the Avista proposal is not significant enough to function as a meaningful incentive to control costs. It also shifts far too much risk to the ratepayer with no corresponding commitment to reduction in the cost of capital that would benefit the ratepayer.

By contrast, with the sharing bands I recommend the excess power costs of $12 million would reduce the rate of return on rate base 1.8 percentage points to 8.6%. This makes the Public Counsel proposal for Avista comparable with rate of return at risk under PSE's sharing bands.

Again, it is also important to recall that, since sharing bands are symmetrical for power cost reductions of $12 million the Company could earn a return on equity of 12.2%.

Q. What transmission cost does Public Counsel propose to be included in the ERM?

A. Public Counsel recommends inclusion of all *variable* transmission expense and revenue in net power cost. These are expenses in purchasing transmission service from others and revenues from sales to others of various transmission services on Avista's system. Avista Witness Mr. William Johnson agrees that these expenses and revenues should be included in net power cost (Exhibit No.__ (WGJ-1T), p. 4, ll.s 5-6).

In addition to these variable costs, however, I also recommend that Company-owned transmission plant used to deliver power to Avista's system (including the interconnection costs) as well as that used to provide access to the market for Avista's excess power should be included in the retail revenue credit portion of the ERM. The retail revenue credit contains the fixed portion of production costs. It should include all associated transmission expenses including depreciation, O&M, insurance and property taxes. By including both variable and fixed costs of power production, the overall costs of power production can be tracked. Thereby, even when variable net power costs increase, the ERM can track a decline in the per-unit cost of fixed power production costs in the retail revenue credit and provide a credit in ratepayers favor. The inclusion of both variable and fixed transmission guarantee that overall variations in the power costs are properly captured.

Q. Does this differ from the Company's proposal on transmission?

A. Unfortunately, Avista's proposal does not include all of the transmission costs as I pointed out above. Mr. Johnson has only proposed inclusion of the variable transmission expenses and revenues in the net power costs, not the fixed Company-owned transmission plant expense in the retail revenue credit.

Q. How does your proposal better meet the principles set out in the PacifiCorp order?

A. The inclusion of both the variable and the fixed portion of transmission expense meets two principles set out by the Commission in the PacifiCorp order. *PacifiCorp Order,* ¶ 91, ¶ 96. First, the Commission stated that a PCA "should not interfere with least cost planning". *Id.* To meet this principle, Avista's ERM should avoid creating a differential ratemaking incentive between two resource choices. This could lead to Avista being in the position of choosing between a resource mix that is least cost and a higher cost resource (to the ratepayers) that has more advantageous regulatory treatment for the Company. This can be avoided by treating substitutes equally. A generation resource distant from load coupled with transmission is an economic substitute for generation close to load. Since generation resources are included in the retail revenue credit, transmission assets should also be included in the retail revenue credit so that either choice the Company makes affects the ERM in the same way.

When load is above the authorized levels in the ERM, either due to abnormal weather or load growth (both beyond the Company's control), the additional revenue collected on production costs is refunded in ratepayer's favor in the retail revenue credit. If fixed transmission plant expenses are not included in the retail revenue credit, the Company can retain the additional revenue from increased load. This is not the case with generation production plant assets which are included in the retail revenue credit and for which a refund for increased load is provided. Note also that the variable cost for generation production is included in the net power costs and under Company's proposal (and Public Counsel's) the variable cost of transmission would also be included.

The second Commission principle applicable here is that a PCA should capture the "variability in the cost of operating *existing* power supply resources as a result of abnormal weather conditions that are out of the utility's control." *Id.*, ¶ 91. Avista has some control over purchasing wheeling or building transmission. Avista Witness William Johnson pointed out in Avista's last rate case that BPA rates have increased by 18%. (Docket UE-050482, Exhibit No. 181, (WGJ-1T), p. 9, ll. 16-18). Avista's choice to build transmission should be include in the retail revenue credit just as the variable wheeling costs/revenue are included in the net power cost. Both these expenses need to be included in the ERM accounting in order to capture the overall net change in costs.

Q. What regulatory review do you suggest for the inclusion of transmission plant in the retail revenue credit?

A. The Commission clearly states: "It is not appropriate to include new resources in a power cost adjustment mechanism. New resources must be considered in general rate cases or power cost only rate cases." *Id.*, ¶ 91. In accordance with this principle, I recommend that Avista's new transmission assets should first be reviewed in a general rate case. Once approved, they can be included in the retail revenue credit factor.

Q. What is the principle for determining which transmission assets to include?

A. Once the Commission determines transmission should be included in the retail revenue credit via review in a general rate case, there are three acceptable methods for determining which transmission assets to include in the retail revenue credit. Transmission used to set transmission rates at FERC could be used. Another method is to use transmission that Avista has recommended to be operated by an RTO or other transmission organization. The third option is to include all 230kV and larger transmission lines. This is my recommendation. This option offers the Commission an easily administered "bright line" test. Avista's annual report to the Commission could serve as one source for identifying these lines.

Q. Are there new resources whose method for being included in the ERM is inappropriate?

A. Yes. Currently under the ERM new power supply contracts of both short-term and long-term duration pass through into the net power supply expenses. This is in direct conflict with the Commission principle that new resources must be considered in general rate cases.

Q. Which type of contracts should be included in the ERM net power supply expenses and which should be set into the authorized net power costs after review in a general rate case?

A. The ERM should not be and does not need to be a replacement for a general rate case prudency review of new resources affecting long-term power cost. I recommend the Commission interpret "new resources" to refer to new or renewed power purchase contracts of longer than 24 months. This cut off is similar to the one used in the PSE PCA and is generally the longest-term contracts trading floors purchase. Again, these would be subject to review in a general rate cases before complete inclusion in the ERM.

In order to treat least cost decisions about how to meet load similarly, I recommend that the some of the cost of long-term power contracts should be included in the net power costs. The maximum amount that should flow through the net power costs from new long-term contracts (including the amount of additional transmission needed to deliver the power) should be the lower of the embedded cost or the average market rate during the term of the contract. The full cost of the contract can be included in rates after approval in a general rate case.

My concern under the current mechanism has been that Avista could pass long-term contracts through the ERM without proper regulatory review by the Commission.

This provides an uneven incentive for Avista to purchase contracts over plant. Such long-term contracts are not short-term variations in power costs that are intended to be captured in the ERM. However, denying the flow through of new contract cost up to the authorized net power costs could place Avista in a regulatory squeeze. If entering a long-term contract replaced short-term buying it would affect the cost in the net power supply accounts. I do not wish to recommend a regulatory review that may unduly hinder least cost planning and decision making. Letting the long-term contract costs, that are below the authorized net power costs, flow through the net power cost accounts allows the Company to recover a large portion of the trade-off between short-term purchased power and the long-term contract costs. I would also note that during at least some seasons or load shapes the new contract may create surpluses to sell to the market which would flow through the net power cost as revenue offsetting expense.

Q. How should major plant outage costs be treated?

A. I recommend that the three base load fuel fired plants, Kettle Falls, Colstrip 3 and 4, and Coyote Springs 2 be treated uniquely with respect to outages. Plant outages that do not exceed the availability factor set in a general rate case do not require any unique treatment. However, for plant outages that exceed the availability factor established in rates, the fixed O&M costs set in rates and a portion of the ratebase of the plant should be removed from the ERM variable costs (net power costs). They would be recoverable in the next general rate case. The purpose is not to punish the Company for outages beyond their control but to require them to demonstrate (1) that fixed O & M costs set in rates were in fact incurred for the time the plant had an outage that reduced the availability factor below that set in rates and (2) that the outage was beyond the control of the Company and therefore the rate base for the plant during the time of the excess outage should be recovered in rates. These items are not difficult for a prudently operated utility to demonstrate. With regard to the plant ratebase, the principle is to have a performance-based threshold -- the availability factor set in rates-- that requires a demonstration of good utility practice if the threshold is not met before plant ratebase can be recovered.

The percentage removed from the variable net power costs is derived by subtracting from 1 the actual availability divided by the proformed availability. The proformed fixed costs would be multiplied by this percentage and the resulting product removed from variable costs.

Q. What is your recommendation of brokerage fees?

A. While these amounts are relatively small, I recommend that brokerage fees for selling or buying power should be included in the net power supply costs. These fees vary with the amount of power bought and sold and are very short-term in nature. In this way they are consistent with the principles set forth in the PacifiCorp order.

Q. Does this conclude your testimony?

A. Yes.