Exhibit No. ___(RJF-15T)
Docket Nos. UE-050482 and UG-050483
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	**Docket No. UE-050482**
v.	)	**Docket No. UG-050483**
AVISTA CORPORATION,	)	*(consolidated)*
Respondent.	)	

REBUTTAL TESTIMONY OF RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

September 22, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who filed direct testimony in this proceeding.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. I will respond to the Joint Direct Testimony of the Signing Parties in Support of the Settlement Agreement (the "Joint Testimony.")

Q. THE SIGNING PARTIES SUPPORT THE SETTLEMENT AGREEMENT. DO YOU?

A. Except for the rate spread provisions, which are addressed by Industrial Customers of Northwest Utilities' ("ICNU") witness Kathryn Iverson, I do not support the Settlement Agreement. In my rebuttal testimony, I will point out many serious problems, oversights, and concerns in the Settlement Agreement. I recommend the Commission reject the document, and decide this case based on the revenue requirement recommendations of ICNU and Public Counsel as applied to Avista's (or the "Company") direct case, or condition its approval on acceptance of additional adjustments that are proposed by Public Counsel and ICNU.

Q. ON PAGE 1 OF THE SIGNING PARTIES' TESTIMONY, IT IS STATED THAT THE SETTLEMENT AGREEMENT REPRESENTS A COMPROMISE AMONG DIFFERING POINTS OF VIEW. PLEASE COMMENT.

A. While the principal Signing Parties (Staff and the Company) may have differing points of view, the absence of support from intervenors representing electric ratepayer interests strongly suggests the "compromise" lacks balance. The Company has the duty to represent its investors, while Staff's role is to balance the interests of ratepayers *and* investors. In this mix, it appears that investors are well represented with two parties supporting their interests. However, no party who unambiguously represents the interests of electric consumers has signed the Settlement Agreement. For this reason alone, the Commission should reject the Settlement Agreement, or condition its approval based on including the adjustments contained in ICNU's testimony.[1/]

Q. DO YOU AGREE THAT THE SETTLEMENT AGREEMENT RECEIVED SIGNIFICANT SCRUTINY AND IS SUPPORTED BY SOUND ANALYSIS AND SUFFICIENT EVIDENCE, AS IS STATED ON PAGE 1 OF THE SIGNING PARTIES' TESTIMONY?

A. No. I will demonstrate many deficiencies in the Settlement Agreement stemming from a lack of consideration of certain critical issues. Most notably, I will show that there has been little consideration of many important power cost issues in the Settlement Agreement, and that unsound analysis underlies crucial aspects of the Settlement Agreement. In fact, an important element of the support given for the narrowing of the Energy Recovery Mechanism ("ERM") deadband is completely in error.

Q. ON PAGE 6 OF THE JOINT TESTIMONY, IT IS SUGGESTED THAT DISCOVERY WAS SUBSTANTIALLY COMPLETE BY THE TIME OF THE AUGUST 3, 2005 SETTLEMENT MEETING. DO YOU AGREE?

A. While discovery was well underway by that time, certain critical issues related to natural gas procurement had not been fully explored. Staff had propounded a series of data requests regarding natural gas procurement for Avista's electric operations, plant maintenance outages, and the CS2 acquisition. However, the

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1/ ICNU also supports many, but not all, of the adjustments proposed by Public Counsel. ICNU's posthearing briefing will identify the Public Counsel revenue requirement adjustments that ICNU supports.

answers were not mailed until August 22, 2005. Thus, it is unlikely any meaningful review of this information was possible by August 23, 2005. Because the Settlement Agreement deals with these issues, this is a serious problem.

Further, the Signing Parties did not have the advantage of having read the direct testimony of ICNU and Public Counsel when the settlement was negotiated. While it is understandable that the Company would prefer to avoid discussing issues raised by intervenors, it is puzzling that Staff would not wish to avail itself of the testimony of ratepayer representatives. This is particularly true when one considers that Staff has a responsibility to *balance* the interests of ratepayers and investors. Staff should not operate in a vacuum ignoring the input of ratepayer representatives.

Q. ON PAGE 7, IT IS SUGGESTED THAT MANY OF THE ISSUES AND ADJUSTMENTS IN THIS CASE RELATE TO ISSUES THAT HAVE ALREADY BEEN DECIDED BY THE COMMISSION. PLEASE COMMENT.

A. This is inaccurate, misleading, and not a fair representation of the Commission's past orders as regards very important issues concerning hydro normalization and natural gas pricing inputs. I will discuss this in more detail later.

1. <u>Elements of the Proposal</u>

Q. STARTING ON PAGE 9, THE SIGNING PARTIES DISCUSS THE ELEMENTS OF THEIR SETTLEMENT PROPOSAL. WHICH ISSUES WILL YOU ADDRESS?

A. I will discuss issues related to weather normalization, power cost modeling, gas price assumptions, and the ERM. I understand that ICNU witness Michael Gorman will address issues related to the rate of return and the Equity Building Mechanism for Avista.

Q. WHAT DOES THE SETTLEMENT AGREEMENT PROPOSE CONCERNING WEATHER NORMALIZATION?

A. The Signing Parties state:

> Some issues arose during the analysis of this case concerning the best method to be applied for weather normalization. *Because there was not adequate time during the settlement discussions to resolve those issues*, the Signing Parties agreed that the Company, Commission Staff and all other interested stakeholders will be invited to participate in a work group tasked with developing a mutually acceptable methodology for future cases.

Joint Testimony at 15-16 (emphasis added).

Q. IS THIS A REASONABLE TREATMENT OF THIS ISSUE?

A. It is cause for concern that the parties could not resolve this issue and decided to "study" it further. The implication is that the parties placed the goal of achieving an early settlement above the goal of obtaining the best possible outcome. There was certainly no reason why the Settlement Agreement had to be negotiated before adequate facts and analyses were available to the parties. There is no necessity for reaching a settlement prior to the deadline for filing of testimony. The parties could have prepared their testimony addressing all issues, and then pursued settlement discussions.

Further, there is no reason why the parties could not have "carved out" this issue and presented their positions to the Commission, having settled other issues.

Finally, as is apparent from the recent experience in the PacifiCorp case (Docket No. UE-032065), often little is accomplished when issues are tabled for later analysis in workshops. In that case, the issue of jurisdictional allocation was set aside for further "cooperative analysis." No resolution of the issue has emerged from that process, and parties are now litigating the issue in the current PacifiCorp proceeding (Docket No. UE-050684).

Q. ATTACHMENT A OF THE SETTLEMENT AGREEMENT CONTAINS APPROXIMATELY $1 MILLION IN POWER SUPPLY COST ADJUSTMENTS. IS THIS REASONABLE?

A. No. In my direct testimony I identified $14.4 million in power supply cost adjustments. These adjustments are either ignored in the Settlement Agreement and supporting Joint Testimony, or replaced with adjustments that are improper, inadequate, and/or incorrect. Further, at least one major adjustment contained in the Settlement Agreement, the CS2 fuel (gas) price update, should be rejected by the Commission on both practical and policy grounds.

Q. PLEASE DISCUSS THE CS2 FUEL PRICE UPDATE IN MORE DETAIL.

A. This adjustment really is purported to address two unrelated issues: an update to the cost of gas for Coyote Springs 2 from $5.94/dth to $7.25/dth, and an adjustment to use a 50-year hydro study:

> The next line, entitled "CS2 Fuel ($7.25/dth)," reflects updating the AURORA power supply run using a more recent fuel price for the Coyote Springs 2 natural gas combustion turbine generator. Because it was a factor incorporated into the AURORA model run, this adjustment also reflects the generation impact associated with using the Staff's 50-year hydro normalization methodology, which is the same methodology the Staff used and the Commission accepted in the most recent Puget Sound Energy general rate case, Docket Nos. UG-040640 and UE-040641.

Joint Testimony at 18.

The Signing Parties contend that both of these adjustments are supported by the Commission's decision in the recent Puget Sound Energy ("PSE") case; this is misleading at the very best.

Q. PLEASE DISCUSS THE 50-YEAR HYDRO STUDY.

A. First, the proposed adjustment does not even reflect the reduction to power costs that would result from use of the 50 water year study. Rather, the CS2 gas adjustment was developed by comparing two separate runs (both made using the 50 water year input) with changes to gas prices. The adjustment was then subtracted from the results of the original 60 water year study. So the adjustment was computed by deducting the difference between two 50-year studies from a 60-year study. What is missing is the adjustment to go from 60 years to 50 years in the first place. Consequently, it is quite misleading for the Joint Testimony to suggest that they have even implemented the 50-year study. In the end, the modeling is a mish-mash of 50 and 60-year studies, but does not reflect the impact of going to a pure 50-year study.

Second, I addressed the issue of the water year studies in substantial depth in my direct testimony, so I will not repeat that here. In my direct testimony, I pointed out that the Commission did not consider the hydro study period to be a settled matter even in the PSE case, and that it invited parties to further analyze the issue. I further pointed out that the "filtered water approach" used in the most recent PacifiCorp case (Docket No. UE-032065) would produce substantially different results.

The signing parties contend that the Settlement Agreement uses "Staff's 50-year hydro normalization methodology, which is the same methodology the Staff used and the Commission accepted in the most recent Puget Sound Energy general rate case, Docket Nos. UG-040640 and UE-040641." Joint Testimony at

18. However, the same could be said of the 40-year "filtered water" study ICNU recommends. It was the methodology the Staff used and the Commission accepted in the 2003 PacifiCorp general rate case. It is particularly troubling that given the disparity in the outcome of these two "Staff endorsed/Commission accepted" methods, Staff was unwilling to agree to bring the matter before the Commission. It appears completely arbitrary as to what method Staff considers reasonable for hydro normalization. This is particularly true in the case of Avista, which, as I discussed in my direct testimony, has both an ERM and has been allowed to defer excess power costs in the past. These two conditions were the very underpinning of the Staff "filtered water" proposal in the 2003 PacifiCorp case.

Q. DISCUSS THE CS2 GAS PRICE UPDATE.

A. Again, the Signing Parties suggest that allowing the Company to update its gas prices using a 90-day rolling average for the period ended September 30, 2004, is in keeping with the Commission precedent in the PSE case (Docket Nos. UG-040640 and UE-040641). I find this surprising for two reasons. First, the Commission clearly indicated in the PSE order that its adoption of the 90-day rolling average was not the last word on the subject. Indeed, the Commission expressed hope that work would continue in developing better methods for gas price forecasting:

> Determination of an appropriate "average price" or "benchmark price" that PSE will pay for fuel gas during the rate year is an exercise in its infancy. It is no older than the [Power Cost Adjustment ("PCA")] mechanism itself, which was approved less than three years ago. It appears from our record that some progress has been made in developing more objective approaches

> to the problem, and we hope that effort by Staff, PSE, and others will continue.

WUTC v. PacifiCorp, Docket Nos. UG-040640, UE-040641, UE-031471, and UE-032043, Order No. 06, ¶ 116 (Feb. 18, 2005).

While the Commission hoped that the efforts of Staff and other parties would continue to develop this issue, Staff apparently ignored that direction in order to bring this case to a premature settlement.

Second, while the Signing Parties "took comfort" in the erroneous "PSE precedent," they completely ignored a far more important Commission decision in yet another recent PSE case. In Docket No. UE-031725, the Commission rejected as imprudent the very gas purchasing strategy assumed to underlie the CS2 gas price adjustment.

Q. PLEASE EXPLAIN.

A. For the use of a 90-day rolling average computed some 120 days before the rate effective period to be accurate, one must assume that the Company makes virtually no forward purchases of gas, and that it is totally committed to a purely short term gas acquisition strategy. Literally, one must assume either that all gas purchased for 2006 by Avista was based on short-term forward strips for the 90-day period ending July 29, 2005, or that somehow, the 90-day rolling average is the forecast of the actual market price of gas in 2006. In either case, it must be assumed that Avista makes no long-term forward gas purchases. However, in PSE Docket No. UE-031725, the Commission investigated that company's purchasing practices and was very critical of a purely short-term purchasing strategy.

Q. PLEASE ELABORATE.

A. Docket No. UE-031725 was a case in which PSE requested changes to its tariffs to reflect costs of energy under its PCA. The major issue in that case concerned PSE's management of the Tenaska gas costs. In 1997, PSE requested permission to buy out of the Tenska contract, projecting savings over the years ahead. As it turned out, the savings never materialized. The Commission ended up making a substantial disallowance because it found that PSE did not prudently manage its Tenaska gas costs. While this case was quite complex, the salient feature of the Commission's decision was the finding that PSE had used a strictly short-term purchasing strategy for gas, rather than rely on longer-term purchasing strategies:

> In any event, PSE's assumption about the market did not materialize. Thus, while PSE was advised to go long on gas for Tenaska, the approach it adopted reflected continued complete reliance on market timing.

WUTC v. PSE, Docket No. UE-031725, Order No. 14, ¶ 49 (May 13, 2004).

> Since 2002, PSE has upgraded its risk management tools and capabilities "to reduce its exposure to spot market uncertainty." PSE states that "In early 2003 the Company developed a dollar-cost averaging strategy that helps the Company protect against volatility in wholesale markets." PSE has considered locking in long-term supply but argues it has not been able to do so "at fixed prices that justify such a step."

Id. at ¶ 64 (internal footnotes omitted).

> PSE stated then in response to questions from the Commission that the Company did not intend to lock-in long-term contracts at the prices available in 1997. PSE stated that it intended to "go to market" to obtain gas to meet the plant's requirements.

Id. at ¶ 73.

> The evidence does show, however, that PSE managed gas acquisition primarily for the short-term bottom line for shareholders. PSE failed to develop and implement a gas-

> purchasing plan that took into account the Company's obligation to manage its gas supply with an eye to securing savings for customers over the longer term.

Id. at ¶ 88.

> By the time of the test-year, it was obvious in the marketplace, and should have been clear to PSE, that any prudent policy for gas acquisition must spread the risk of price volatility to significantly dampen its potential effects on total costs. This was evident from the advice PSE received from experts it employed, from its own review of its gas-purchasing practices, and from other cases at the Commission. It is clear to us that during the test year PSE did not have a prudent purchasing strategy in place. Instead of developing a comprehensive strategy and a balanced approach considering opportunities in short-term, intermediate-term, and long-term gas markets, PSE simply continued its practice of buying in the short-term market. Even though the Company recognized the need for an alternative strategy, it did not develop and implement one.

Id. at ¶ 91.

Q. THERE WAS A DISSENTING OPINION IN DOCKET NO. UE-031725. DID ALL OF THE COMMISSIONERS AGREE WITH THE COMMENTS CONCERNING THE IMPRUDENCE OF PSE'S PURELY SHORT-TERM PURCHASING STRATEGY?

A. Yes. In the dissenting opinion, Commissioner Oshie agreed with the majority as regards the issue of imprudence, but disagreed with respect to the remedy. While he supported the disallowance, he also recommended eliminating the return on the Tenaska regulatory asset. On the issue of prudence, the dissenting opinion stated as follows:

> Regrettably, the savings anticipated [from the Tenaska contract buyout] have not been realized for reasons directly related to the Company's failure to react reasonably to a rapidly changing and volatile natural gas market and the risks attendant. In short, the natural gas market changed dramatically between 1997 and 2003, yet the Company's purchasing strategy unabatedly trod the same path, as if the changing world would have no affect upon it.
>
> The current situation, whereby the regulatory asset is not producing the savings upon which its creation was predicated, has

> resulted in part from the Company's imprudent management of fuel acquisition since the energy crisis in 2000 and 2001. *Because the Company did not develop and implement a fuel acquisition strategy for Tenaska to protect against the known risks of exclusive reliance on short-term markets after market prices abated in the second half of 2001, it lost the opportunity to mitigate the gas prices it faces in the market today, which again are high and may go higher yet. Indeed, the facts of this case show a persistent failure on PSE's part, even after the energy crisis, to recognize the need for a balanced approach to gas acquisition for Tenaska including taking advantage of opportunities in the long-term market, as well as in the short-term market.*

Id. at ¶¶ 141-42 (emphasis added).

Q. TIE THIS TO THE SETTLEMENT AGREEMENT.

A. In this proceeding, the Signing Parties would embed a purely short-term purchasing strategy into the Avista power cost study. The assumption made by the Signing Parties is that Avista would (and arguably *should*) rely solely on short-term gas for the test period. Currently, gas prices have increased substantially, and the perils of such a short-term strategy are quite obvious. In effect, the Signing Parties assume the proper purchasing strategy for Avista is one the Commission has already found to be imprudent. If the Commission accepts this aspect of the Settlement Agreement, in effect, it will be endorsing a short-term purchasing strategy. This may make it much more difficult to invoke a prudence disallowance at a later time. This clearly runs counter to the Commission's view of prudent gas purchasing in Docket No. UE-031725. As I will discuss later, when coupled with the proposal to narrow the ERM deadband to $3.0 million, this aspect of the Settlement Agreement will likely place ratepayers at risk for recovery of substantial gas cost increases stemming from Avista's lack of a long-term gas acquisition strategy.

Q. IS THE PROPOSED CS2 GAS PRICE ADJUSTMENT CONSISTENT WITH AVISTA'S ACTUAL GAS PURCHASES TO DATE?

A. No. Exhibit No.___(RJF-16) is a copy of the Company's response to ICNU Data Request No. 5.3. This Table shows actual purchases made to date by Avista. While the information confirms Avista's total lack of long-term forward purchases, it also shows the Company has made substantial purchases at prices below the $7.25/dth price. Indeed, the average price for all forward purchases made to date was $6.85/dth. Consequently, the assumed price of $7.25/dth is inconsistent with actual purchases and is therefore not a known and measurable change.

Q. THE SIGNING PARTIES CONTEND THAT THE CS2 ACQUISITION WAS PRUDENT. PLEASE COMMENT.

A. It appears that this finding would be binding on the Commission if the Settlement Agreement is accepted. While the Signing Parties contend that many different prudence issues were examined, the analysis of the gas purchasing strategy for CS2 again contradicts the Commission's views as stated in Docket No. UE-031725. The Joint Testimony states as follows:

> **Q. Did Staff consider the impact of natural gas prices in its evaluation of CS2?**
>
> A. Staff noted that CS2 is fueled by contracts with TransCanada Gas Transmission Northwest for transmission on a mileage based rate and suppliers in AECO-C but did not include any review of the future gas fuel cost since there is no specific commodity contract in place. *Like many gas turbines, CS2 is fueled by commodity deals which include month ahead, year ahead and other products. In the current climate of energy markets, this is not surprising. The fuel price estimate used in the production cost model, Aurora, is estimated on a three-month rolling average of NYMEX strips,* which after adjusting for basin

> differentials, are used as a predictor of spot gas prices in Sumas, AECO, Rockies and San Juan gas markets. This method was recommended in the final Commission Order in a recent electric general rate case for PSE, Docket No. UG-040640/UE-040641 and is acceptable to Staff for this case.

Joint Testimony at 23-24 (emphasis added). Basically, the Staff findings concerning the prudence of CS2 completely ignore the Commission's view that a purely short-term gas acquisition strategy is imprudent.

Q. IS IT ACCURATE TO SUGGEST THAT A PURELY SHORT-TERM GAS ACQUISITION STRATEGY IS THE NORM FOR COMBINED CYCLE UNITS?

A. No. PacifiCorp, for example, has a long-term contract for its Hermiston plant. The fuel cost for that unit, as shown in the PacifiCorp filing in UE-050684, is $3.3/MMBtu. See Exhibit No.___(RJF-17). This is far less than half the figures used in the Settlement Agreement for CS2.

Q. SHOULD THE COMMISSION ACCEPT THE CS2 FUEL PRICE ADJUSTMENT CONTAINED IN THE SETTLEMENT AGREEMENT?

A. No. The Commission should reject this adjustment and continue to use the gas prices filed by the Company in its direct case. While that also assumes a purely short-term purchasing strategy, it would at least place the Company at risk for its reliance on a short-term strategy.

Q. THERE WERE A NUMBER OF OTHER POWER SUPPLY COST ADJUSTMENTS IN THE SETTLEMENT AGREEMENT. DO YOU AGREE WITH THOSE ADJUSTMENTS?

A. I agree with the CS2 Transportation Adjustment, as it merely corrects an error in the original filing.

I disagree with the Colstrip maintenance adjustment, however. The Joint Testimony describes this as adjusting "costs associated with Colstrip utilizing a maintenance schedule more closely tied to historical planned outages of the plant." Joint Testimony at 19. This adjustment is a substitute for the adjustment I proposed related to the Colstrip planned outages, as shown on Table 1 of my direct testimony. The Signing Parties' version of this adjustment used in the Settlement Agreement is not realistic.

Q. PLEASE EXPLAIN.

A. The Company originally assumed that the Colstrip planned outages would be spread out evenly throughout the year, much like unplanned, or forced, outages. In the Settlement Agreement, the Signing Parties assumed that 20% of the planned outage days would occur in March, 30% each in April and May, and 20% in June. However, this is not a reasonable representation of either history, as claimed in the Joint Testimony, or of expected maintenance for Colstrip for 2006. Exhibit No.___(RJF-18) shows the actual and forecast planned outages for Colstrip from 2000-2006. See also Exhibit No.___(RJF-11).

This table shows that for the entire period 2000-2006 (no maintenance was planned for 2005), the actual distribution would be 8% for March, 29% for April, 40% for May, 22% for June, and 1% for July. Thus, the Signing Parties' adjustment overstates the amount of planned maintenance in both March and April and understates the amount in May and June.

Even if one looks only at the historical period, 2000-2004, similar results emerge. The planned outage days in March are substantially overstated, while May and June are understated in the Signing Parties' adjustment. Consequently, it is simply wrong to assert that the maintenance schedule assumed in the model is a good representation of history.

Q. IS THE PROPOSED PLANNED OUTAGE SCHEDULE A GOOD REPRESENTATION OF THE 2006 TEST YEAR?

A. No. In 2006, 84% of the planned outage days will occur in May and June and only 16% in April. Thus, the Signing Parties planned outage schedule is completely at odds with the actual plan for the test year.

Q. ARE THERE ANY OTHER REASONS WHY THE PLANNED OUTAGE SCHEDULE USED BY THE SIGNING PARTIES SHOULD NOT BE USED?

A. Yes. For purposes of setting normalized rates, historical patterns of planned outages are inappropriate in a fundamentals based model such as Aurora. Aurora develops its own market price forecast for setting normalized rates. These forecasts may differ from historical price patterns, particularly as regards the annual shape of prices. Under normalized conditions, planners should attempt to plan outages to minimize costs. Normalized rates should assume that planners do succeed in minimizing costs and should maximize planned outages in months when normalized market prices are lowest. Because market prices are lowest in May and June, those months should be the time when the Colstrip outages are scheduled. As a result, I believe my original adjustment is much more reasonable in the context of the Aurora model and is further supported by the actual 2006 schedule.

Q. IS THERE ANY OTHER REASON WHY THE COMMISSION SHOULD REJECT THE SIGNING PARTIES' PROPOSED COLSTRIP ADJUSTMENT?

A. This adjustment was estimated outside of the Aurora model. In contrast, my adjustment was based on a rerun of the model. Consequently, my adjustment should be more realistic.

Q. DOES THE SETTLEMENT AGREEMENT ADDRESS THE OTHER POWER SUPPLY COST ISSUES YOU RAISED IN YOUR DIRECT TESTIMONY?

A. No. As I pointed out in my direct testimony, the document does not address issues related to the Colstrip upgrade and outage rates, the planned outages of resources not owned by Avista, hydro shaping, or bidding factors. Because these are all legitimate issues the Commission should consider, I urge rejection of the Settlement Agreement.

2. <u>ERM Deadband</u>

Q. DO YOU AGREE WITH THE PROPOSAL TO NARROW THE ERM DEADBAND?

A. No. I already discussed this issue in my direct testimony. However, I will address it further in the context of the CS2 gas price adjustment discussed in the Joint Testimony, and the justification for this proposal contained in the Joint Testimony.

Q. YOU HAVE ALREADY DISCUSSED WHY THE SETTLEMENT AGREEMENT'S TREATMENT OF CS2 FUEL PRICES IS INCONSISTENT WITH THE COMMISSION'S VIEWS AS EXPRESSED IN DOCKET NO. UE-031725. PLEASE ELABORATE ON WHY THE DEADBAND PROPOSAL RUNS CONTRARY TO THAT DECISION.

A. One of the strongest points the Commission made in its order in UE-031725 was its view that ratepayers should not shoulder risks that are more appropriately borne by investors. In narrowing the deadband, the Signing Parties would increase the risks assigned to ratepayers and place more reliance on the prudence standard of cost recovery, as prudence would be the only major standard that the utility would have to meet in obtaining recovery of the great majority of its power supply costs. The Commission has already criticized over reliance on prudence as regards power cost matters in its order in Docket No. UE-031725:

> All parties couch their arguments in terms of prudence, but the Company argues that prudence is independent of the various "benefit-caps" urged by the other parties to limit recovery. *We think prudence matters, obviously, but is not dispositive on a stand-alone basis, either. Using prudence alone, at least as articulated by the Company in this instance, would completely sever the present from the past, giving no weight to the underlying reason and expectations around which the regulatory asset was created. The Company would have us look only at whether its decisions were prudent during the test period. If they were, then all costs would be allowed—gas costs, return of the regulatory asset, and return on the regulatory asset (all, however, subject to other mechanisms such as the PCA) regardless of whether the costs produce the benefits intended, or any benefits at all. This approach places too much risk on the ratepayers, under the specific facts of this case.*

Docket No. UE-031725, Order No. 14 at ¶ 83 (emphasis added).

My reading of that passage is that in regards to fuel and power supply cost matters, the Commission has stated it does not consider the prudence standard alone. The alternative to prudence (as discussed in Paragraphs 84 and 85 of the order in Docket No. UE-031725) is the used and useful standard, whereby investors assume the full risk associated with the decisions made by the managers they appoint. The Commission rejected sole reliance on the used and useful standard as well, but instead adopted a "hybrid approach." In my view, this "hybrid" approach would not support the proposal to narrow the deadband.

Under the existing deadband and sharing mechanism, investors were at risk for $9.0 million in power supply costs in the event the Company failed to forecast those costs accurately or to acquire power at prices low enough to meet their forecast. Conversely, if the Company was successful and enjoyed power supply costs less than projected, it would reap the first $9.0 million in benefit.

In proposing to narrow the deadband, the Signing Parties now seek to assign 2/3 of these power supply risks to ratepayers instead of shareholders. Naturally, the narrowing of the deadband does not eliminate risk, it merely assigns the risk to ratepayers (who can do nothing about it), and takes it out of the hands of management (who have the duty to manage the Company along with the risks it faces). Consequently, the reasoning contained in the Joint Testimony at page 26, which asserts that the "changes in costs included in the ERM are driven primarily by factors that are beyond the Company's control," is completely specious. Ratepayers have *no* control over Avista's power supply costs, while the Company most certainly has control over its resource acquisitions, purchasing strategies, and the timing of rate case filings in situations where power supply costs exceed those already included in rates. In Docket No. UE-031725, the Commission clearly articulated its view that a purely short-term purchasing strategy was imprudent, and that there is a limit on the amount of risk ratepayers should bear. I am amazed that Staff would enter into a settlement that completely ignores both of these very strong statements by the Commission.

Q. A SUBSTANTIAL PORTION OF THE LIMITED JUSTIFICATION FOR NARROWING THE ERM DEADBAND WAS THE ARGUMENT THAT SMALL CHANGES IN GAS PRICES OR HYDRO LEVELS WOULD CAUSE THE COMPANY TO EXCEED THE DEADBAND. PLEASE COMMENT.

A. These statements reveal that the Signing Parties did not properly consider the implications of the proposal to narrow the deadband. For example, the Joint Testimony states as follows:

> In addition, Avista also relies on significant natural gas purchases to supply fuel for its natural gas fired thermal units. A $1.00/dth change in the cost of natural gas to run Coyote would equal approximately $15.7 million on an annual basis, or $10.2 million for the Washington jurisdiction, which would exceed the $9.0 million deadband.

Joint Testimony at 26. This statement is completely misleading if not blatantly erroneous. The reason is that it ignores the fact that if gas prices increase, wholesale power prices will increase as well. In the Aurora run designed to implement the CS2 fuel adjustment, gas prices were increased by much more than $1.28/dth. However, Washington jurisdictional power costs increased by approximately $3.6 million. The reason is that when gas prices increased for CS2, they also increase for all other suppliers in the wholesale market. This results in increased market prices. Because Avista is a net seller in the market, these higher prices offset most of the increase in the cost to run Coyote Springs. Consequently, this justification for narrowing the ERM is simply wrong, based on the Company's own Aurora study.

Q. IS THERE ANOTHER EXAMPLE OF THIS SAME PROBLEM?

A. Yes. On page 26 of the Joint Testimony we find this statement (footnote omitted):

> As a hydro-based utility, Avista serves approximately 50% of its customers' load requirements with hydroelectric generation. Because of this heavy reliance on hydro, it takes only a 7% change in hydroelectric generation within the year to fill the $9.0 million deadband. That is, a 7% change in hydro, up or down, would cause the Company to either absorb $9.0 million or benefit by $9.0 million.

Again, this statement contradicts the results of the Aurora model. Based on my regression analysis of Aurora outputs, a 7% change in hydro would produce a $7.45 million change in Washington jurisdictional power supply costs. The Signing Parties' testimony exaggerates the significance of this problem. Thus, the proposal to narrow the deadband is supported by faulty analysis.

Q. WHATEVER THE SENSITIVITY TO HYDRO CONDITIONS OR GAS PRICES, IS NARROWING THE DEADBAND THE CORRECT POLICY FOR DEALING WITH VOLATILE POWER COSTS?

A. No. Ironically, by narrowing the deadband, the Commission would be sending the Company exactly the wrong message. In fact, it would be legitimizing a "victim" mentality that suggests the management of a utility is helpless to deal with changes in costs. It would suggest that the management of the utility is nothing more than a bystander, totally at the mercy of the whims of the markets. The truth is just the opposite. Utilities have the long-term ability to select their resource mix. If gas is expensive and volatile, and hydro unpredictable, coal or wind powered resources may be attractive options to diversify Avista's portfolio. However, by assuring full recovery of nearly all fuel and purchased expenses, the Commission is giving the Company the incentive to do nothing. Rather than exploring for new resource options to balance its portfolio and manage its risk, the Company will know that it can simply pass-through energy costs to consumers.

Consequently, the perceived risk of investment in new resources will likely be higher than the risk of volatile power supply costs. In the end, narrowing the ERM deadband will provide a far greater obstacle to dealing with the problem of volatile power supply costs because it will reduce the incentive of management to reduce risks for investors.

3. <u>Continuation of the ERM</u>

Q. WHAT IS YOUR RECOMMENDATION AS REGARDS THE ERM?

A. I continue to recommend elimination of the ERM at the end of 2005. There is yet one more flaw in the Settlement Agreement and the Joint Testimony in that both documents simply assume that continuation of the ERM is appropriate without any justification. I urge the Commission to consider the issue of regulatory and policy implications of the ERM in this docket.

Q. IS RETENTION OF THE ERM A GOOD POLICY DECISION?

A. No. There are many policy concerns created by the ERM. A major problem with the ERM is that in the current environment, it creates disincentives to maintain or increase investment in generation, as mentioned above.

Any pass-through mechanism provides a utility with an incentive to purchase wholesale energy instead of increasing (or even retaining) investment in generation. The reason for this is that by decreasing generation investment, return requirements decrease, thereby reducing the need for base rate increases. If there is a pass-through mechanism for fuel and purchased power, the utility may prefer to simply minimize investment and instead purchase high cost fuel and energy in the market.

Such situations do not always arise from to the decision to build new generating capacity or make purchases. In fact, many types of efficiency improvements requiring capital investment may be avoided when an automatic adjustment clause is present. Finally, the investments in question may not even involve generating capacity. Transmission upgrades might also be minimized at the expense of higher purchased power costs, given the presence of the ERM.

Q. DOES THE ERM CREATE OTHER DISINCENTIVES FOR EFFICIENCY?

A. Yes. The ERM causes major differences between the revenue effects of different kinds of resources and the accounting treatment of certain kinds of costs. Generally, variable power supply expenses are passed through in the ERM, while investments are not. Without the ERM, the Company will have the incentive to minimize costs between rate cases, and would naturally select the lowest cost resources. With the ERM, the Company may have a financial incentive to select resources that are afforded full pass-through recovery, irrespective of total cost.

As just one example, consider a situation where Avista might have an unfavorable coal-supply contract, or had a supplier default on a contract. In both cases, the Company would likely incur legal expenses to undertake litigation with the supplier. However, with an ERM, legal expenses are not a pass-through, while fuel and purchased power are.[2/] In both cases, the Company would have much less incentive to undertake the litigation necessary to obtain relief with the ERM in place.

[2/] This is not purely hypothetical. I have been involved in cases where utilities requested to include legal fees in fuel cost recovery because absent this, they did not have the incentive to mount legal challenges of fuel supply contracts.

I am also aware of cases in which a utility settled a lawsuit related to nuclear plant construction by offering the complainant an attractive long-term power contract.[3/] In such cases, the settlement to the litigation could result in higher power costs for ratepayers, particularly for a utility with pass-through accounting.

As another example, consider outage costs. Outages can be reduced through a program of preventive maintenance and other "best practices." However, outage costs are largely a pass-through under the ERM, while the higher O&M expenses associated with reducing outages are not. Consequently, the Company has little incentive to incur the additional costs needed to minimize outages.

Ultimately, sensitivity to cost is simply not as great when costs are passed through to customers. The prices paid for purchased power become much less important to shareholders when the ratepayers are responsible for paying all or a significant portion of these costs between rate cases. The self-interest of shareholders is perhaps the greatest regulatory force of all. Regulatory lag *between* rate cases creates pressure on the part of management to minimize costs. This provides incentives to minimize outages and use the least cost power supply strategy.

Rate cases are intended to provide sufficient time to examine costs, and prudence, reasonableness, and accounting issues can be fully explored. Under the ERM review process there is little opportunity to review the components of actual

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3/ These cases were related to the PacifiCorp contract with Sacramento Municipal Utility District, and litigation over the South Texas Project between Houston Lighting and Power and Central Power and Light Company.

power supply costs. As a result, there is great danger that ratepayers will pay for costs that are not fair, just, and reasonable ratemaking expenses.

Q. HAVE OTHER UTILITY EXECUTIVES EXPRESSED VIEWS REGRADING PASS-TRHOUGH MECHANISMS THAT CORROBORATE YOUR COMMENTS ABOVE?

A. Yes. PacifiCorp had a similar pass-through mechanism in Utah until 1990. However, that Company requested elimination of its Energy Balancing Account ("EBA"). Re Utah Power & Light, Utah Public Service Commission Docket No. 90-035-06. In his May 1990 testimony before the Utah Commission, PacifiCorp witness Verl R. Topham testified that elimination of the then existing EBA was necessary for several reasons. Mr. Topham argued that the EBA impeded the ability of management to respond appropriately to competition and to "manage the Company." Exhibit No.___(RJF-19) at 5:5-22. Mr. Topham further argued that an EBA had the unintended tendency to benefit or penalize customers as actual retail loads fluctuated from test period loads. He also stated that it raised questions about retroactive ratemaking. Id. at 5:23 – 6:2.

Q. DID MR. TOPHAM DISCUSS THE REASONS BEHIND THE REQUEST TO ELIMINATE THE EBA IN UTAH?

A. Yes. At that time, the Company was concerned about the need to *reduce* prices due to declining fuel costs. Mr. Topham testified that from March 1988 to May 1990, changes in EBA collections resulted in substantial price reductions. This ran counter to PacifiCorp's goal of "price stability." Id. at 12:24 – 14:1.

Q. DID MR. TOPHAM INDICATE THAT THE MANAGEMENT OF THE UTILITY, NOT THE CUSTOMERS SHOULD BEAR POWER COSTS RISKS?

A. Yes. The following question and answer is included in Mr. Topham's testimony:

> Q. The EBA is a mechanism which places the risk of fluctuating power costs on the customer. If the EBA were terminated, this risk of fluctuating power costs would be placed on the Company. Why is the Company willing to accept this risk?
>
> A. The Company is willing to accept this risk because we believe the risk is manageable. *The Company believes in placing the risk of management practices on those that make the business decisions – management – not customers.*

Id. at 14:17-26 (emphasis added.)

Utilities in the Northwest have tended to use pass-through mechanisms as a tool in situations of rising costs and price volatility, while abandoning them when times are better. It should not be lost on the Commission that the 1990s (when the above mentioned Utah case took place) were characterized by falling fuel and wholesale power prices, while the present day is one of rising and volatile costs. Now the Signing Parties seek to place the ever greater risks of *increasing* commodity prices on ratepayers—not management or shareholders. However, it would not be a surprise at all, if in a few years, when power supply costs moderate, Avista might seek to end its pass-through mechanism, in the hopes of retaining price reductions between rate cases.

Q. DOES MR. TOPHAM'S TESTIMONY CORROBORATE ANY OTHER COMMENTS YOU MADE EARLIER?

A. Yes. Mr. Topham testified that certain kinds of transactions would likely be evaluated on the basis of their impact on the EBA. Id. at 15:13-22. Mr. Topham also testified that the presence of an EBA would make it less attractive for the Company to acquire new resources. Id. at 16:8 – 17:1. He indicated the EBA could create situations where it would be less advantageous for the Company to reduce overall costs, if it meant decreasing eligible costs at the expense of increasing some other type of cost. Id. at 17:4-23. Overall, Mr. Topham's arguments against the use of a pass-through mechanism are as true today as when they were written fifteen years ago.

Q. IS THERE ANOTHER, MORE RECENT, EXAMPLE OF AN EXECUTIVE OF ANOTHER REGIONAL UTILITY PROVIDING TESTIMONY AGAINST PASS-THROUGH MECHANISMS FOR POWER COSTS?

A. Yes, in Oregon Docket No. UE 113, Ms. Pamela Lesh testified that Portland General Electric Company ("PGE") dislikes true-up mechanisms because they reduce incentives for management and the concept of rate finality is violated:

> Philosophically, we dislike the idea of a true-up. Even with use of variance sharing, the true-up weakens the utility's incentives to manage its business and it seriously detracts from the value customers receive in knowing that the price they pay for electricity used today is the actual price. Few people would be willing to buy an airline ticket if, several weeks after the flight, the airline could send another bill - or a refund check for that matter - based on the final count of seats taken in the plane or some such set of actual inputs. People generally like price certainty. *Until our customers have a choice of products, we would prefer not to require all to choose an electricity product that does not include price finality as a feature.*

Exhibit No.___(RJF-20) at 2 (Re PGE, OPUC Docket No. UE 113, PGE/100, Pollock-Lesh/13 (Aug. 16, 2000)) (emphasis added).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.