Exhibit No. ___(RJF-1T)
Docket Nos. UE-050482 and UG-050483
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

DIRECT TESTIMONY OF RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

(Confidential Information Removed and Empty Spaces Blacked Out)

August 26, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU"). My qualifications are presented in Exhibit No.___(RJF-2).

Q. WHAT KIND OF CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design, and energy cost recovery issues.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses Avista's (or the "Company") Aurora model study of normalized power supply cost for the pro-forma period, January 2006 to December 2006. I identify a number of problems in the Aurora study that overstate the Company's revenue requirement. I also address the Company's proposed changes to the Energy Recovery Mechanism ("ERM") and certain other revenue requirements issues.

Q. DOES ICNU SUPPORT THE STIPULATION BETWEEN AVISTA, THE STAFF, NWIGU, AND THE ENERGY PROJECT (THE "SIGNING PARTIES")?

A. No. The Stipulation provides modest reductions to the Avista requested rate increase that are inadequate to address all of the issues that impact Avista's overall revenue requirements. However, the Signing Parties have not yet filed testimony supporting the Stipulation, and discovery regarding the Stipulation has not been completed at this time. Further, the Stipulation documents do not provide workpapers or further details regarding many of the adjustments utilized in the Stipulation. I expect those issues will be explained in more detail in the testimony filed by the Signing Parties. Consequently, ICNU will file additional testimony regarding the Stipulation on September 22, 2006.

In this testimony, I will primarily address Avista's original request in this case because it appears that many (if not most) of the issues that I address are common to both the Stipulation and the Avista requested increase. When possible, I will then compare my results to the results obtained in the Stipulation to demonstrate that the Stipulation is inadequate.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Table 1 summarizes my recommended test year power supply costs and other revenue requirement adjustments. My major findings and recommendations are as follows:

1. **Avista's request for $125.96 million in (Total Company) power supply costs is substantially overstated. I recommend a number of adjustments, resulting in a reduction to Washington power supply costs. Table 1, below, summarizes the impact of each of my proposed adjustments. I also show the Power Supply Costs used in the Stipulation. As Table 1**

shows, my adjustments are substantially greater than the minimal power supply cost reductions built into the Stipulation.

2. **The hydro modeling issues confronting the Commission in this case include the question of which and how many water years should be modeled in the power cost study. In the past two major electric rate cases (Puget Sound Energy, Inc. ("PSE") Docket No. UE-040641 and PacifiCorp Docket No. UE-032065), the Staff proposed (and the Commission accepted) two diametrically opposed hydro modeling premises. The Commission should use this case to clarify its policy regarding hydro generation modeling.**

3. **I recommend that the Commission adopt the hydro modeling method applied in the PacifiCorp case because it is a more appropriate technique for Avista. In the PacifiCorp case, the Commission adopted a modeling method proposed by Staff witness Buckley that excluded outlier water years in the 40 year study. Applying this method to Avista results in a reduction to power supply costs as shown in Table 1. Attachment A to the Stipulation does not identify any water year adjustment in the Stipulation.**

4. **Irrespective of the modeling approach or water years selected by the Commission, the Commission should remove the 1973 and 1974 water years from the power cost study. The Aurora model produces spurious results for those years that bias the overall power supply costs estimates. It appears that this problem has been ignored in the Stipulation.**

5. **Avista's modeling of hydro resources is flawed because it uses a five-year average hydro shape to determine the hourly dispatch of hydro resources. In actual practice, dispatchers attempt to maximize hydro revenues by scheduling output to coincide with periods of highest market prices. It appears that the Stipulation does not consider this issue. Correcting this problem reduces power costs by the amount shown in Table 1.**

6. **Avista's modeling of the Colstrip plant overstates power costs by using unreasonable assumptions regarding planned outages and overall outage rates. Avista further ignores capacity upgrades for these units scheduled to occur during the rate effective period. The impact of these adjustments is shown in Table 1. While Attachment A to the Stipulation shows an adjustment for Colstrip maintenance, the amount of the assumed adjustment is inadequate and unexplained.**

7. **The Aurora database overstates power costs further by use of unrealistic outage schedule assumptions for other regional power plants. It appears that the Stipulation does not address this issue. Correction of this problem reduces power costs by the amount shown in Table 1.**

8. The Commission should reject the "bidding factors" applied by the Company in the Aurora model. The purpose of bidding factors is to force the model to replicate the results of Avista's forward curve. However, forward curves present just one more forecast methodology which changes over time. There is no reason to elevate the significance of the forward curve over the model result. The Stipulation appears to utilize the same bidding factors as the Avista filing. Table 1 shows the impact of this adjustment.

9. Avista has made pro-forma adjustments related to wheeling expense and the Kaiser DES contract. These adjustments are based on unrepresentative data and/or are unsupported by the Company. Again, these issues are apparently not addressed in the Stipulation. Reversing these adjustments results in further power supply cost reductions shown in Table 1.

10. I recommend the Commission reject the Stipulation proposal to narrow the ERM deadband to $3.0 million and instead terminate the ERM at the end of 2005. I recommend the Commission clarify the requirements for Avista to file deferral applications in situations where power costs variations are substantial.

Table 1
Summary of Recommended Adjustments
$1000

	Total Company	Washington Jurisdiction
		65.16%
I. Aurora Power Supply Cost Issues:	-$21,510	-$14,016
1 1939-1978 Year "Filtered Hydro"	-$8,346	-$5,438
2 Hydro Shaping	-$4,260	-$2,776
3 Colstrip Capacity	-$2,197	-$1,432
4 Colstrip Planned Outages	-$2,521	-$1,643
5 Colstrip Outage Rate	-$1,220	-$795
6 Generic Plant Maintenance	-$550	-$358
7 Bidding Factors	-$2,416	-$1,574
II. Other Power Supply Cost Issues:	-$519	-$338
1 Wheeling Expense	-$200	-$130
2 Kaiser DES Contract	-$319	-$208
Total Power Supply Cost Adjustments:	-$22,029	-$14,354
Avista Request	$125,959	$82,075
Total ICNU Recommended Power Supply Costs	$103,930	$67,721
Stipulation Adjustments	-$1,521	-$991
Total Stipulation Power Supply Costs	$124,438	$81,084
Rate Base Adjustment (Increase - Colstrip Upgrade)	$1,945	$1,267
Depreciation Adjustment (Increase - Colstrip Upgrade)	$100	$65

II. POWER SUPPLY COST ISSUES

Q. WHAT ARE "POWER SUPPLY COSTS" AND WHY ARE THEY IMPORTANT TO THIS PROCEEDING?

A. Power supply costs are the variable production costs related to fuel and purchased power expenses, net of power sales revenue. The Avista calculation also includes transmission wheeling revenues and expenses, rents, water supply costs, and other expenses related to power supply. *See* Exhibit No.___(WGJ-2). Power supply costs comprise a substantial portion of the overall revenue requirement, and thus, are a significant component of Avista's proposed base rates. In this case, the Company requested an increase of $28.5 million in power supply costs compared to its last general rate case. *See* Exhibit No.___(WGJ-1T) at 5, Table 1. This amounts to nearly 80% of the overall original requested increase of $35.8 million. Thus, power supply costs are a substantial component of the overall rate increase and warrant substantial analysis by the Commission. As shown on Table 1, above, the Stipulation reduces overall power supply costs by less than $1 million for the Washington jurisdiction. I will demonstrate that the Stipulation has failed to address many power supply cost issues adequately, and as a result, overstates the allowance for power supply costs.

Q. HOW DOES AVISTA ESTIMATE POWER SUPPLY COSTS?

A. The Company uses the Aurora model, a PC based software product licensed from EPIS Inc. Avista's use of the Aurora model warrants extra scrutiny by the Commission because this is the first case in which Avista has used the model to set rates.

Q. HAVE YOU BECOME FAMILIAR WITH THE AURORA MODEL?

A. Yes. ICNU obtained a license from EPIS to utilize the Aurora model in this proceeding. I received training from EPIS regarding use of the model in July 2005. I also obtained additional support from Avista and EPIS regarding operation of the model via various telephone conversations and email correspondences. I also have extensive experience working with other power supply models, including PacifiCorp's PD-Mac and GRID models, Portland General Electric Company's ("PGE") Monet model, and numerous other industry standard models such as PROMOD and PROSCREEN.

1. <u>Hydro Generation Modeling</u>

Q. DISCUSS THE SIGNIFICANCE OF HYDROELECTRIC RESOURCES TO AVISTA'S POWER SUPPLY COSTS.

A. Hydro resources supply 52.5% of Avista's system load. *See* Exhibit No.___(CGK-3). As a result, modeling of all aspects of hydro generation is critical to the development of sound estimates of normalized power supply costs for the Company. A critical element in determining Avista's power supply costs is the proper technique for normalization of hydro generation. There are a number of issues surrounding this topic, the most important being the determination of what constitutes a proper set of water years for use in simulating Avista's power costs.

Q. PLEASE EXPLAIN THE CONCEPT OF "WATER YEAR" SIMULATIONS.

A. The annual supply of hydro electric energy is a function of snowpack, snowmelt, run off, and precipitation in the mountains surrounding the river systems that host the dams operated by Avista and other regional utilities. As a result, the availability of hydro generation is largely a matter of weather and geological factors. Because weather is subject to fluctuation over time, hydro generation varies substantially from year to year. As a result, it is important to develop power supply cost estimates that reflect the variations in hydro generation over time. This has typically been done by hydro-dependent utilities through use of simulation models that estimate power supply costs as a function of available hydro generation and many other inputs. The most common approach has been to simulate historical water conditions over a large number of years, averaging the final results of the individual water year scenarios. This methodology develops an "expected value" power supply cost.

Q. DOES USE OF MULTIPLE WATER YEAR SCENARIOS GIVE RISE TO ANY SPECIAL ISSUES FOR COMPANIES SUCH AS AVISTA?

A. Yes. As early as the 1970s, multiple water year scenarios were used by utilities in Washington to estimate power supply costs for rate case purposes.[1/] The question of how many, and which water years are required to provide a reasonable simulation has been an issue in many previous proceedings before the WUTC. In this case, Avista has requested a 60 water year study encompassing the period 1929 to 1988. Selection of different water year periods (for example, 40 or 50 years) provides somewhat different power supply cost results. Indeed, Mr. Kalich demonstrates a potential difference of more than $9 million depending on whether a 40, 50 or 60 year period is used. *See* Exhibit No.___(CGK-1T) at 7. This issue

[1/] I recall this from my employment with Puget Sound Power and Light in the late 1970s.

is obviously quite important and has been litigated in cases for many years before the WUTC.

Q. GIVEN THE IMPORTANCE OF THIS ISSUE, AND THE NUMBER OF TIMES IT HAS BEEN LITIGATED IN THE PAST, HAS THE COMMISSION ESTABLISHED A CLEAR PRECEDENT?

A. No. In fact, there are a variety of past decisions that support differing approaches regarding this issue. Based on prior cases one could find at least some support for a 40, 50, or 60 water year period. Further, Commission decisions in the most recent cases have adopted methods that differ substantially in their underlying premises and assumptions.

Q. PLEASE ELABORATE

A. Traditionally, Avista used a 40-year rolling average in hydro modeling. However, in Cause No. U-85-36 the Company requested a 50-year rolling average (1929-1978). In that case, the Commission rejected the Company proposal and affirmed the 40-year rolling average (1939-1978). It appears that the 1985 case was Avista's last fully litigated general rate proceeding to address this issue. Thus, one might conclude that for Avista, the Commission's precedent remains use of a 40-year rolling average.

The use of the 40-year rolling average was reaffirmed by the Commission in its order in a 1992 PSE case:

> The Commission accepts the Commission Staff position, and directs the company to continue to use a 40-year rolling average. The Commission believes that the parties spent far too much time revisiting this issue. They repeated arguments and evidence that they have presented in previous rate cases. [Staff witness] Mr. Winterfield's presentation in Docket No. U-89-2688-T demonstrated convincingly that the cumulative error would be less under a 40-year rolling average than under the company's

> proposal. While a rolling average may not be the most precise estimate, errors tend to offset one another as the method is applied over time. The evidence presented in this proceeding does not persuade the Commission that hydro availability is subject to cycles or trends. The company is put on notice that this will remain the Commission's position on this issue unless and until a clear and convincing argument supports a superior alternative.

WUTC v. Puget Sound Power & Light Co., Docket Nos. UE-921262, UE-920433, and UE-920499, Eleventh Supp. Order at 43 (Sept. 21, 1993).[2/]

Undaunted by this strong precedent, in its 1999 case, Avista requested a 60-year hydro study (1929-1988). WUTC v. Avista, WUTC Docket No. UE-991606, Third Supp. Order at ¶ 146 (Sept. 29, 2000). The Commission approved a settlement agreement that utilized the average of the 60-year and 40-year (1949-1988) studies. Id. at ¶ 147; Exhibit No.___(CGK-1T) at 4. While settlements generally do not constitute precedent, the outcome of the 1999 case certainly suggests recent Commission acceptance of both the 40 and 60 year studies. However, more recent cases involving PSE and PacifiCorp prove even more contradictory.

Q. DISCUSS THE PSE CASE.

A. In PSE Docket No. UE-040641, that company proposed use of the 60 water year study (1928 to 1987), while Staff witness Dr. Yohannes K.G. Mariam recommended a 50 water year study (1928 to 1977). Both witness supported their position on the basis that the proposed period was normally distributed and showed no statistically significant time trend. Both witnesses presented substantial statistical analysis supporting their contentions. Dr. Mariam presented

2/ Avista was also a party to that proceeding.

an argument that up to date "rule curves" were not used in developing the last ten years of the 60-year study, and thus, recommended against inclusion of those data. Ultimately, the Commission accepted the 50-year study proposed by Dr. Mariam in place of the 60-year study proposed by PSE.

Q. IS THE PSE ORDER THE FINAL WORD REGARDING THIS ISSUE?

A. No. In its order, the Commission also stated as follows:

> We are mindful, however, of Dr. Dubin's testimony that all available data should be examined, and Mr. Schoenbeck's testimony that the Commission should use all available 120 years of available data if it elects not to use the 40-year rolling average. In this case, ICNU did not demonstrate that data for the period 1879 to 1928 was verified or verifiable. Nor did it suggest a detailed methodology for using such data, which would take into account such factors as the non generation uses of the river system. We encourage the parties to continue their discussions of this subject and their efforts to develop even more rigorous tools for hydro normalization.

<u>WUTC v. PSE</u>, Docket Nos. UG-040640, UE-040641, UE-031471, and UE-032043, Order No. 06 at ¶ 131 (Feb. 18, 2005) (internal citations omitted).

Further, the most recent PacifiCorp case provides a much different approach to hydro normalization that must be considered in the context of this proceeding.

Q. DISCUSS THE 2004 PACIFICORP CASE.

A. In Docket No. UE-032065, PacifiCorp filed its request using a 40 water year study (1939-1978), based on existing precedent for that Company. However, Staff witness Buckley recommended use of a 40-year "filtered water" study, where "outlier" water years, those more than one standard deviation beyond the mean annual generation, were excluded. Mr. Buckley's basis for this proposal was the fact that utilities would request deferrals or Power Cost Adjustment mechanisms ("PCAs") in situations where extreme hydro conditions occurred:

> **Q. Why does Staff propose a different methodology at this time for this PacifiCorp?**
>
> **A.** Two factors led Staff to conclude that an alternative approach is appropriate. The first is the recent, very real tendency for the regulated electric utilities to request rate relief when higher than expected actual power supply expenses occur due to "unforeseen" events. Bad water years and their effect on actual power supply costs have been cited as one of the unforeseen events.
>
> * * *
>
> Two of the three regulated electric utilities now have some form of power cost adjustment mechanism. A Washington islanding or stand-alone approach may include some form of hydro adjustment to address the variability in generation from hydro resources in the Western Control Area. Such a hydro adjustment would address the more significant variations in water conditions throughout the region. It is therefore unnecessary, and even incorrect, to include the power supply costs associated with all water year conditions in the determination of the base power supply costs when a hydro adjustment mechanism exists. The effects on power supply expense of water years above or below some level can be addressed in the mechanism.
>
> * * *
>
> *There is no need to burden Washington customers with rates designed to recover long-term extremes in power supply costs due to stream flow variations.* In the event an extreme year occurs that adversely affects power costs between now and the next general rate case, the Company can make a filing to recover those costs. The adoption of this water year methodology is also appropriate under any scenario. Whether through a hydro adjustment mechanism or [through] a separate filing requesting relief from drought conditions, it may be in the best interests of customers to see the cost effects of stream flow variations. *Embedding the effects of the more extreme stream flow conditions is tantamount to paying an insurance premium and then hoping the Company will have sufficient funds to pay the claim.*

WUTC v. PacifiCorp, WUTC Docket No. UE-032065, Direct Testimony of Alan P. Buckley at 124-27 (July 2, 2004) (emphasis added). Exhibit No.___(RJF-3) presents a complete copy of the pertinent pages of Mr. Buckley's testimony.

Q. HOW DOES STAFF WITNESS BUCKLEY'S ARGUMENT COMPARE TO THAT PRESENTED BY DR. MIRIAM IN THE PSE CASE?

A. The two witnesses present concepts and arguments that are substantially at odds. Aside from differing on the 40 and 50 water year studies, Mr. Buckley testified that extreme conditions should be excluded from the development of normalized rates. Dr. Miriam testified it was crucial to include all of the extreme events:

> In Docket No. UE-921262, Staff recommended using the most recent 40 water years. Public Counsel conducted a statistical significance test between the data that contained stream flow records for the period 1928-47 (20 years) and 1948-87 (40 years). The data for the first period are characterized by abnormally low water years. As a result, the mean from these two time periods were found to be statistically different. Staff and Public Counsel recommended excluding the period 1928-1932 that contained relatively low hydro years. *The critical period of 1928-1932 defines how much hydro system energy should be considered firm under a worst case scenario.*
>
> *In this proceeding, Staff did not divide or group the data into two periods because the critical time periods have to be included in modeling the hydroelectric system. Inclusion of critical hydro years is similar to assuming a design or coldest day in history when planning for gas*. Based on time series statistical analysis, Staff concluded that the data is normally distributed and showed no trend (trendless). Thus, there are no grounds to exclude critical periods or to divide the data into separate groups. Consequently, Staff did not analyze the most recent 40-water years for use in hydroelectric modeling.

WUTC v. PSE, WUTC Docket Nos. UG-040640, UE-040641, UE-031471, and UE-032043, Direct Testimony of Yohannes K. G. Mariam at 24-25 (Sept. 23, 2004) (emphasis added).

While Mr. Buckley testified that rates should not be designed to recover long term extremes, Dr. Miriam considers inclusion of "worst case scenario" essential.

Q. EXPLAIN THE SIGNIFICANCE OF THIS.

A. In contrast to Mr. Buckley's position that the extreme conditions should be excluded, Dr. Mariam was adamant that extreme events should be included in the hydro modeling period employed. In this regard, Dr. Mariam would apparently make no distinction between a Company with a PCA (or an ERM) and one that does not have such a mechanism. Further, Mr. Buckley recommended a 40 water year study (1939-1978) while Dr. Mariam included the years 1929-1938 in his recommended 50 water year study (1929-1978). Dr. Mariam's insistence on the inclusion of the first ten years is significant because that period encompasses the second worst multi-year drought in the Northwest in the past 250 years. This is demonstrated in Exhibit No.___(RJF-4) at 23. This exhibit is a copy of an academic paper entitled "*Columbia River Flow and Drought Since 1750*." Ironically, Mr. Buckley did not even consider the first ten years of the period, and then excluded all subsequent observations that departed by more than one standard deviation from the mean.

Clearly, the Staff positions in the two prior cases (both conducted at nearly the same time) are diametrically opposed. This case presents the Commission with the opportunity to decide among these competing theories.

Q. DID THE COMMISSION ACCEPT THE STAFF PROPOSAL IN THE PACIFICORP CASE?

A. Yes. However, the PacifiCorp case resulted in a contested settlement between Staff and the Company. In the Stipulation, the Company agreed to Staff's proposed hydro normalization adjustment. While the Stipulation was opposed by ICNU and Public Counsel, to my knowledge, no party opposed the hydro normalization adjustment. Appendix B to the Stipulation Document in the PacifiCorp case clearly identified the fact that "extraordinary" hydro years were excluded from the normalization.

Q. DOES THE FACT THAT THE COMMISSION'S ADOPTION OF THE STAFF'S "FILTERED WATER" APPROACH OCCURRED IN THE CONTEXT OF A SETTLED CASE DIMINISH ITS PRECEDENTIAL VALUE?

A. Certainly settled cases generally do not provide as clear a precedent as a fully litigated case. However, as noted above, the case was contested and fully litigated by certain parties. Further, in its first order approving the Stipulation in PacifiCorp's general rate case, the Commission chose to amend the Stipulation in its treatment of certain deferred costs. WUTC v. PacifiCorp, WUTC Docket No. UE-032065, Order No. 06 (Oct. 27, 2004). Thus, the Commission can reject treatments contained in settlement agreements when it does not agree with them. Finally, the Commission was certainly aware of the issue, and the premise underlying the Staff proposal. Had the Commission believed Mr. Buckley's hydro normalization was incorrect, the Commission could have modified it. Ultimately, the PSE case, the PacifiCorp case, and prior Avista cases leave the question of the Commission's preference regarding this issue unsettled. Further, in the PSE case, the Commission invited parties to continue to analyze the issue. Therefore, this case provides the Commission the opportunity to clarify its position regarding hydro normalization, and to select between the two competing theories presented by Staff in 2004.

Q. DOES THE STIPULATION SPEAK TO THIS ISSUE?

A. No. There is no reference in the Stipulation or in Attachment A to any adjustment for a different water year period. Consequently, it appears that the Stipulation uses Avista's requested 60-year study.

Q. WHAT QUESTIONS SHOULD THE COMMISSION ADDRESS IN THIS PROCEEDING AS REGARDS THE ISSUE OF HYDRO NORMALIZATION?

A. There are two important issues. First, the Commission must decide whether outlier water years are to be included or excluded from the normalization procedure. Second, the issue of which and how many water years to include must be decided as well. If the Commission merely accepts the Stipulation without addressing this issue, many open questions will remain for future cases. Further, ratepayers will be charged costs well above reasonable levels.

Q. SHOULD THE COMMISSION EXCLUDE OUTLIER WATTER YEARS FROM THE NORMALIZATION PROCEDURE AS MR. BUCKLEY RECOMMENDED IN DOCKET NO. UE-032065?

A. Yes. Mr. Buckley's proposal was a sensible recommendation given the Commission's current regulatory policies and practices as applied to Avista. Indeed, because Avista already has a power cost adjustment mechanism (the ERM) and has been granted the right to defer excess power costs in prior years (while neither was true for PacifiCorp), Mr. Buckley's proposal is far more appropriate in this case than it was for PacifiCorp.

Q. EXPLAIN THE NEXUS BETWEEN DEFERRALS OF EXCESSIVE POWER COSTS AND THE HYDRO NORMALIZATION TECHNIQUE.

A. Putting aside, for the moment, the issue of the ERM, the option of a utility being allowed to defer excess power costs in extreme event water years (e.g., multi-year droughts) necessitates the exclusion of such water years in the hydro normalization procedure to eliminate a potential problem of double recovery.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE THIS?

A. Table 2 presents a hypothetical example to explain this problem. In the example, the utility uses a power cost model to compute normalized power costs on the basis of five different hydro generation scenarios. The table shows a hypothetical company that has an average of 500 megawatts ("MWs") of hydro, and replacement power costs $30/MWh. It shows that under normalized ratemaking customers are charged $100 million per year as the average cost of power based on average hydro over a five-year period (simplified from the 40, 50, or 60 years actually used). Over five years, the results would all average out and customers would pay the total actual cost of power supply costs, $500 million. The $500 million figure includes both good and bad hydro years. The normalized cost of $100 million is lower than the cost of power in below average hydro years, but higher than the cost of power in good hydro years. By using the average value, a "premium" is built into the normalized cost of power in good years that provides a form of "insurance" against bad hydro years.

Assume now that year five is the worst hydro year and the utility requests a deferral to allow it to ultimately recover the additional power costs. If regulators allow the Company to have a deferral in a bad hydro year, they get the benefit of the "premium" built in during the good years, and then effectively charge the actual cost in year five. Under this scenario, ratepayers pay the normalized cost of power ($100 million) for the first four years and the actual cost of power in year five. The total cost of power to customers in that scenario is $526 million, resulting in an overcharge to customers of $26 million over the five year period.

Table 2
Example of Overcollection Problem

Year	Hydro Avg. mW	NPC M$	Normalized Ratepayer Cost	Ratepayer Cost Cost with Deferral Y 5
1	600	73.7	100.0	100.0
2	550	86.9	100.0	100.0
3	500	100.0	100.0	100.0
4	450	113.1	100.0	100.0
5	400	126.3	100.0	126.3
Avg.	500	100.0	100.0	
Total Ratepayer Cost		500	500.0	526.3
			Overcollection	26.3

In the example above, the higher than normal costs of a bad hydro year ($26 million) are averaged into rates every year. However, instead of getting a "free pass" when the bad hydro year actually arrives, customers are now required to pay for bad hydro conditions as well. When above normal hydro conditions occur, customers pay the normalized cost and the company keeps the savings. When below normal hydro conditions occur, the company requests a change to the rules of the game and asks for recovery of its total cost. This is a "heads I win, tails you lose" type of hydro normalization process.

Q. GIVEN THE PROBLEM ILLUSTRATED ABOVE, WHY WOULD REGULATORS ALLOW DEFERRALS IN POOR HYDRO YEARS?

A. While regulators may be concerned about the inequity of the situation, the reality is that financial exigencies may force the Commission to approve a deferral. This illustrates the problem alluded to by Mr. Buckley in his PacifiCorp testimony that customers pay the "insurance premium" hoping the Company will be able to "honor the claim."

Q. THE ABOVE EXAMPLE ASSUMES THE COMMISSION WILL ALLOW DEFERRALS IN EXTREME HYDRO CONDITIONS. HOW DOES YOUR ANALYSIS CHANGE WHEN THE ERM IS CONSIDERED?

A. The ERM was not intended to deal with extraordinary deviations in power costs, only ordinary ones, as I will discuss shortly. However, it is ICNU's recommendation that the Commission terminate the ERM, as will also be discussed later in this testimony. Therefore, the above example is pertinent as deferrals will replace the ERM in extreme circumstances.

Further, the presence of an ERM merely pre-specifies the rate treatment of costs related to hydro (and all other) sources of variation. Fundamentally, the ERM shifts power supply risks away from the utility, onto the customer. Because of this, it is even less appropriate for customers to be assigned the risk of extreme hydro events in base rates. This was precisely Staff witness Buckley's premise in Docket No. UE-032065.

Finally, there is a general opposition to ERM or other PCA type mechanisms by regulators and ratepayer advocates. It is no coincidence that the

ERM first materialized in 2002, in the aftermath of the Western Power Crisis, and a period of poor hydro conditions. It would not be at all surprising if the Company were to suggest elimination of the ERM in period of favorable power cost and hydro conditions. Given the general antipathy of ratepayers for cost plus ratemaking, it would not be out of the question for the ERM to be eliminated at such a time. In this sense, the deferral example above is pertinent again because the ERM may be thought of as being little more than a structured deferral scheme that extends over a number of years, and is requested by utilities when times are bad, but eliminated when times are good.

Q. WHAT IS THE IMPACT OF USING THE "FILTERED WATER" METHODOLOGY IN THIS CASE?

A. Exhibit No.___(RJF-5) shows the Aurora model power cost results based on the filtered and non-filtered approach. Overall, 12 different scenarios are presented. Mr. Buckley's approach, using the 1939-1978 data would result in power supply costs $8.3 million less than the Company 60-year (1929-1988) proposal.

Q. WHAT HYDRO NORMALIZATION METHODOLOGY DO YOU RECOMMEND?

A. From a policy perspective, Mr. Buckley's PacifiCorp proposal makes far more sense for Avista than Dr. Mariam's methodology from the PSE case. Avista already has an ERM, and has in the past been granted a substantial power cost deferral in a period of poor hydro and high power prices.[3/] Dr. Mariam's approach would exclude recent data, but specifically includes data from one of worst multi-year droughts in the past 250 years. Consequently, I recommend the

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[3/] Avista accrued $217,803,712 in deferred energy costs to Account 186, "Miscellaneous Deferred Debits," from July 2000 through December 2001, pursuant to the Commission's orders in Docket Nos. UE-000972 and UE-010395.

Commission apply the same methodology for Avista as it accepted in the PacifiCorp case, using the 1939-1978 water year data, filtered to remove water years more than one standard deviation beyond the mean. The results of this analysis are shown Table 1.

Q. DO YOU FIND FURTHER SUPPORT FOR THE FILTERED WATER CONCEPT IN THE COMMISSION ORDER IN DOCKET NO. UE-011595?

A. Yes. In that Order, Paragraphs 38 and 39 state as follows:

> We also clarified through colloquy with the witnesses, that the ERM is intended to address only the ordinary variations in power costs that may occur going forward, not extraordinary costs. Mr. Norwood, for example, testified that:
>
>> if you had a 100-million-dollar situation, then it would operate just as is shown here, and that is the first nine million would be absorbed by the Company. There would be a 90 percent deferral for any amount above that, and once you hit the 27.8-million trigger, we would file with the Commission to adjust rates. If the balance continues to grow, then it would be up to the Company then to come to the Commission to say that we have an extreme extraordinary situation and request the appropriate relief at that point in time, but that would be outside of this ERM mechanism. It could be done in the context of a general rate case or request for some kind of emergency relief.
>
> In a similar vein, Mr. Elgin testified that:
>
>> The ERM is designed to deal with the expected normal variability of hydro. If you look at Exhibit 16, this was the prosym modeling of the water records that the Company has, and the ERM is a mechanism designed to deal with those variations in hydros and the expenses on the Company, and this is a modeling of that. From Staff's perspective, this settlement agreement does not deal with extraordinary circumstances that we dealt with in 2000, 2001 period that gave rise to the existing deferrals. . . This settlement does not deal with those conditions. It just can't. Those impacts and costs are too big, and we have to deal with that on the cases and the circumstances as they arise,

> and this is how staff would view this settlement operation, the operation of this settlement document.
>
> *TR. 184-85.* There is nothing in the Settlement Stipulation that precludes the Company from seeking relief from extraordinary or other circumstances that call for modification of the ERM. Indeed, paragraph 4(c) on page 7of the Settlement Stipulation provides that Avista may seek to modify the ERM "on or before December 31, 2006."

WUTC v. Avista, WUTC Docket No. UE-011595, Fifth Supp. Order at ¶¶ 38-39 (June 18, 2002).

From this passage, it is clear that the ERM was intended to deal only with *ordinary variations* in power costs, while more extreme situations were expected to be dealt with in deferrals or via rate cases. This strongly suggests that Dr. Mariam's concept from the PSE case of building into rates extreme conditions is out of step with the Commission's existing regulatory treatment of Avista. Overall, this passage in the Commission's order bolsters the argument for use of the filtered water method because only that approach recognizes the likelihood that the Commission may find it necessary to grant power cost deferrals in extreme circumstances.

Q. CAN YOU DEMONSTRATE THAT THE RESULTS OF YOUR RECOMMENDED APPROACH ARE CONSISTENT WITH OTHER REASONABLE APPROACHES?

A. Yes. Exhibit No.__(RJF-5) also demonstrates that the filtered water approach for the period 1939-1978 produces results quite comparable to those that would result from use of the 50-year period (filtered) advocated by Dr. Mariam in the PSE case (1929-1978) and the results for the more recent 40-year period (1949-1988) whether filtered or not. Once the filtering technique is applied, there is less difference between the results of the various scenarios than exists when the raw data itself is applied. This is another advantage of the methodology in that it makes the decision as to which time period to use less significant.

2. Water Year Period

Q. BASED ON YOUR PRIOR TESTIMONY, IT APPEARS YOU SUPPORT THE USE OF THE 40 WATER YEAR PERIOD FROM 1939-1978. WHY DID YOU SELECT THAT PERIOD?

A. Frankly, I am not terribly concerned whether the 40-year period from 1939 to 1978 is used or the 40-year period from 1949-1988 is used, particularly if filtering is applied. As noted in Exhibit No.___(RJF-4), the 1949-1988 period is one that was free of multi-year droughts, thus the filtering technique makes little difference, as can be seen in Exhibit No.___(RJF-5). However, Dr. Mariam contended in the PSE case that the last ten years of data (1979-1988) were not developed using proper rule curves. In this case, Mr. Kalich argues this problem is insignificant. However, to avoid entanglement in this controversy, I don't object to exclusion of the last ten years of data. Because the ten-year period from 1929-1938 included the second worst multi-year drought in the past 250 years, these years should be excluded in any case. Further, examination of the full pool of available stream flow data and generation data from 1879 to 2004 supports use of the 40-year (1939-1978) study.

Q. IN THE PSE CASE, ICNU ALSO DISCUSSED USE OF THE ENTIRE POOL OF AVAILABLE STREAM FLOW DATA (1879 TO PRESENT). HOWEVER, THE COMMISSION HAD SOME CONCERNS WITH THE APPLICATION OF THIS DATA. HAVE YOU PERFORMED AN ANALYSIS THAT WOULD ADDRESS THE COMMISSION'S CONCERN?

A. Yes. In the PSE case, ICNU witness Mr. Schoenbeck testified that if the 40-year average data was not used, then entire range of available data from 1879 should be used. The Commission questioned whether the data could be verified, and whether it could account for non-generation factors. The Commission also noted that a methodology for application of the data had not been presented. I have performed a detailed analysis of all available 1879 to 2004 stream flow and generation data to address the issues that concerned the Commission.

Q. REGARDING VERIFICATION, WHAT DATA IS AVAILABLE FOR THE LONG-TERM RECORD?

A. I used data referenced by Mr. Kalich in his Exhibit No.___(CGK-2). This provides data for stream flow at the Dalles from 1879, for Priest Rapids from 1918, from the Spokane River from 1892, and from Clark Fork from 1929. This data is available from the United States Geological Survey and there should be no *a priori* reason to doubt its validity. By performing regression analysis, I determined that all these stream flows were all highly correlated. Because the data for the Dalles was available for the longest period, I correlated Priest Rapids, Spokane and Clark Fork to the Dalles. The correlation coefficients for all three data series were .90 to .97 indicating excellent agreement. This high degree of correlation is to be expected as the four systems are obviously impacted by essentially the same climatic conditions. This analysis supports the consistency of this data and provides a degree of verification of some of the early data.

Further, Exhibit No.___(RJF-4) reports on the use of tree ring data (calibrated over the period 1931-1987) to reconstruct the stream flow at the Dalles from 1750 to 1987. These data were calibrated against the recorded data from 1931 to 1987, and then used to recreate historical stream flows. Overall the tree ring analysis tends to confirm the early stream flow data in that it shows exceptionally high flows in the 1880s and lower flows in the 1890s. This is a key finding because it is the high flow periods of the 1880s that tend to increase the average stream flows over the 126-year period.

Q. HOW DID YOU DEAL WITH THE PROBLEM OF NON-GENERATION USES OF WATER IN YOUR ANALYSIS?

A. Avista provided annual generation (based on the Northwest Power Pool model that incorporates non-generation uses into the energy production calculation) for Mid-Columbia, Clark Fork, and Spokane from 1929 to 1988. This data was extremely well correlated to the annual stream flows. Thus, I developed a linear regression model relating annual energy production to stream flows.

Q. HOW DID YOU DEVELOP GENERATION FOR THE PERIOD 1879 TO 2004?

A. In every single case where actual data was available, I used it. Otherwise, I used the regression models to fill in missing data for stream flow and hydro generation. For the period where annual generation was already available (1929-1988 and 2000-2004), I used the actual data generation data. For years where actual generation or stream flow data was not available, I used the equations relating the stream flows at Priest Rapids, Clark Fork and Spokane to the Dalles, to fill in any missing years. For example, for Spokane, I only needed to apply the Spokane vs. Dalles regression for 1879-1917. Using the actual or regression annual stream flows for each source I then applied the stream flow vs. generation regressions to develop annual generation years for the period 1879 to 2004 when actual data was not available.

Q. GIVEN THE ANNUAL GENERATION, HOW DID YOU ESTIMATE POWER COSTS?

A. Aurora results for 1929-1988 were applied directly for those years,[4/] and then used to develop a regression between power cost and annual hydro energy. Again the two series were highly correlated (r = .97) and showed no significant evidence of non-linearity. This process allowed me to develop annual power costs each year for the period 1879 to 2004, using Aurora output results for 1929 to 1988 and the equation for the remaining years. Naturally, one might run the model for the entire period, however, given the high degree of correlation between the model results and annual hydro generation, the impact should be minimal.

Q. WHAT WERE THE RESULTS OF THIS ANALYSIS?

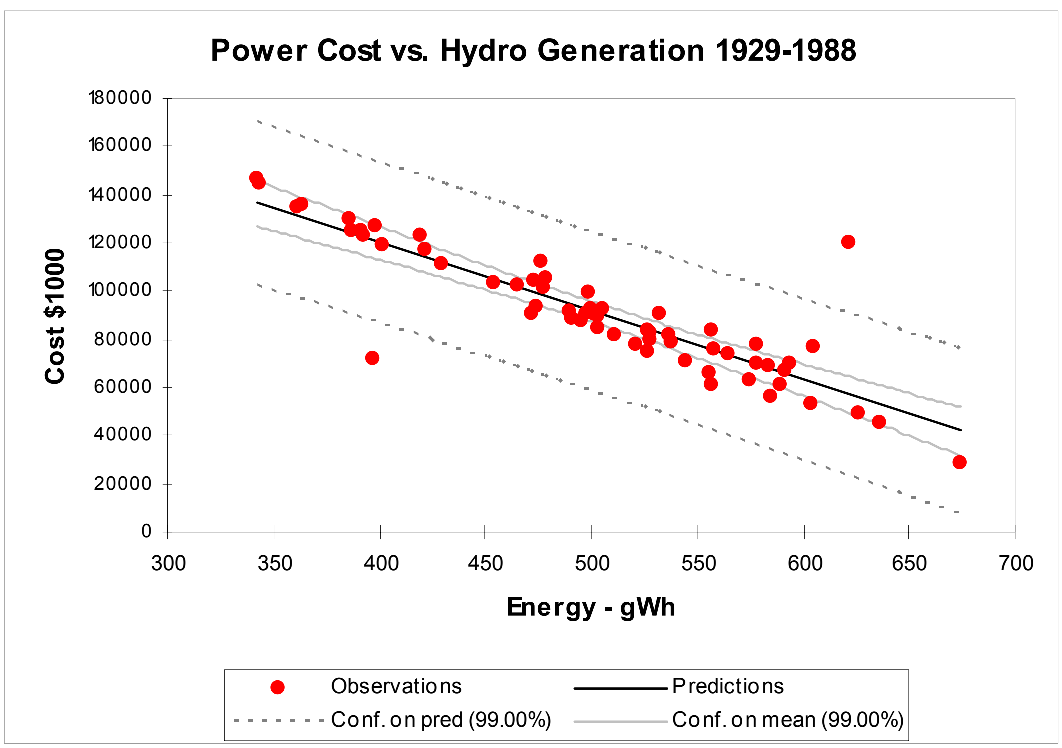
A. The 126 year study is also shown on Exhibit No.___(RJF-5). A summary of the study is shown in Exhibit No.___(RJF-6). The analysis demonstrates that using the entire 126-year record would predict power cost results in Aurora for Avista of $85.6 million, a level essentially identical to the traditional 40-year (1939-1978) result. This strongly suggests that whether the Commission decides to use the filtered water approach or not, use of the 40-year study (1939-1978) is very

[4/] The years 1973 and 1974 were excluded, however, for reasons to be discussed later.

reasonable, as it provides for a level of generation that is comparable to that which would likely result if a much longer record of data (including very bad droughts and very wet periods) were used. While I do not recommend the 126-year study, per se, it certainly supports the reasonableness of my recommended 40-year study.

Q. HAVE YOU DISCOVERED ANY PROBLEMS IN THE AURORA MODEL AS A RESULT OF YOUR INVESTIGATION OF HYDRO MODELING?

A. Yes. As part of my analysis, I examined the annual power supply cost results from Aurora for the period 1929 to 1988. In examining the data, it became apparent that the results for two years, 1973 and 1974, were extremely anomalous, falling far outside the realm of reasonable results for the model in scenarios with comparable hydro levels. The chart below vividly illustrates that these two years are extreme outliers in the Aurora model.



Q. DO THESE ANOMALOUS DATA POINTS RESULT IN AN INCREASE TO POWER COSTS?

A. Yes. These data points result in $172,000 higher cost if the 60-year (unfiltered) series is used, and $220,000 higher cost if the 50-year (unfiltered) series is used. Because 1973 and 1974 correspond to extreme water years as well, elimination of this problem has no impact on the filtered model results. If the Commission decides against the use of a filtered approach, this correction should be made to whatever model data period it selects. As in the case of water year modeling in general, it appears that the Stipulation does not consider this issue.

3. <u>Hydro Shaping</u>

Q. HOW DOES AURORA SHAPE THE HOURLY OUTPUT OF HYDRO RESOURCES?

A. In Aurora, hydro output is shaped to parallel hourly load inputs. However, Avista has modified that technique for its own resources and uses an average monthly shape based on five years of historical data. In both cases, these assumptions are out of step with actual operation.

Q. PLEASE ELABORATE.

A. Hydro plant operation is impacted by a variety of factors, but to the extent possible, dispatchers attempt to utilize hydro to minimize cost. Thus, the operation of hydro will be affected by both loads and market prices. In general, operators try to maximize the revenue produced by hydro plants (the sum of hourly hydro outputs and hourly market prices). In Aurora, Avista fails to capture these dynamics. Instead, Avista's own hydro resources are scheduled based solely on *historical* shapes. For non-Avista hydro resources, Aurora simply follows hourly loads, ignoring market prices.[5/]

While neither assumption is realistic, given Avista's heavy dependence on hydro generation, it is clear that the former is the most troubling. Because the supply of hydro in the market as a whole is a much smaller fraction of total supply than is the case for Avista, the most significant problem is Avista's treatment of hydro for its own resources.

Q. [redacted]

5/ In theory, market prices would tend to follow loads. However, market prices derived from Aurora often do not do so. This may be due to variety of factors, including transmission constraints, or must run requirements.

[redacted]

Q. ARE THERE CONSTRAINTS THAT PREVENT THE COMPANY FROM TAKING MAXIMUM ADVANTAGE OF ITS HYDRO RESOURCES?

A. I am certain that there are. However, the same is true of virtually every other resource available to the Company. Despite this, operators continue to do their best to optimize the dispatch of all units.

Q. IS THERE ANY LOGICAL REASON WHY THE HYDRO DISPATCH SHOULD FOLLOW HISTORICAL HOURLY SHAPES, WHILE THERMAL UNITS ARE DISPATCHED ON THE BASIS OF THE TRADING CURVE?

A. No. All units have operational constraints that limit their flexibility. Still, the system dispatcher does the best job possible to minimize cost. Considering that hydro is Avista's most important and lowest cost resource, it would be just as reasonable for the Company to dispatch the much higher cost Colstrip or Coyote Springs units on the basis of historical profiles. Yet the Company allows Aurora to instead follow its built-in optimization logic and perform a trading curve dispatch for these and all other thermal plants. It should apply the same cost-minimization principle to the dispatch of hydro resources as it does for thermal plants.

Q. DO INDUSTRY STANDARD MODELS ASSUME OPTIMAL DISPATCH OF HYDRO PLANTS?

A. Yes. I have studied virtually all of the major utility industry standard models during the course of my career. I also developed production cost models used by many utilities for development of avoided costs for Public Utility Regulatory Policy Act compliance in the early 1980s. All of the major production cost models in use by the industry over the last 25 years model optimal dispatch of hydro, and in fact, all types of resources. There are two reasons that models develop optimal solutions, even when they may not be fully attainable in practice. <u>First</u>, utilities have a responsibility to regulators to minimize costs for ratepayers. Industry standard models assume this responsibility is met. <u>Second</u>, in a modeling context, cost minimization is an objective standard. While it may not be met perfectly in practice, building logic into models that systematically assumes costs are not minimized is even more problematical and ultimately becomes much too subjective. For example, should we assume in the model that economic dispatch is 100%, 95%, 80%, or less successful? Where would one draw the line? It becomes a very slippery slope once one begins to assume that performance of the system dispatcher will be systematically deficient. In that case, one may as well simply ask the Commission to arbitrarily inflate all power cost estimates to make up for sub-par performance. Regulators have never made such assumptions in the past, and they never should do so in the future.

In cases where it is systematically impossible to optimize the dispatch for a given resource, the proper modeling approach is to identify the cause, and insert additional logic to simulate the applicable constraints. Consequently, most models develop a "constrained" optimal dispatch.

Q. IS THIS ISSUE ADDRESSED IN THE STIPULATION?

A. No. None of the adjustments identified in Attachment A address this problem.

Q. HOW COULD ONE PROPERLY MODEL AVISTA'S HYDRO UNITS IN AURORA?

A. The most common approach used in industry standard production cost models is to develop logic to optimize the dispatch of hydro based on hourly market prices. For example, in GRID, PacifiCorp dispatches hydro in two parts. Non-discretionary hydro is dispatched around the clock (representing minimum loadings, run of river, or other operating constraints). The remaining discretionary hydro energy is dispatched to minimize cost. Exhibit No.___(RJF-7) is a copy of a graph showing the PacifiCorp methodology.

PGE also recently modified its own model, Monet, to use a similar optimization approach for hydro in place of the use of historical shapes. This was the result of a settlement in Oregon Public Utility Commission ("OPUC") Docket No. UE 149. In that proceeding, the circumstances were quite similar, and I pointed out similar deficiencies in the Monet model logic. As part of that settlement, PGE worked with the parties (myself included) in workshops to develop logic to simulate the economic dispatch of its hydro resources.

Q. HAVE YOU DEVELOPED AN ANALYSIS THAT APPLIES THIS OPTIMIZATION LOGIC TO AURORA?

A. Yes. I used the hourly Aurora output data to develop a re-dispatch of the Avista hydro based on the PacifiCorp GRID and PGE Monet optimization techniques. The monthly non-discretionary energy was based on the monthly minimum hydro capacity from the five-year average shapes developed by the Company. The peak hydro capacity was based on the peak monthly output based on the same data. I "turned on" the discretionary hydro when market prices reached a trigger price. The trigger price was varied to use most (but not all) of the available discretionary energy. Any "fine-tuning" needed to match total monthly energy available was done by adjusting the non-discretionary energy. This modified logic decreases 2006 power costs by the amount shown in Table 1. Exhibit No.___(RJF-8) summarizes the results of this analysis.

Q. DO THESE STRATEGIES ACCOUNT FOR RESERVES OR OTHER ANCILLARY SERVICES?

A. Yes. The maximum monthly hydro generation is still well below the actual capacity of the individual units. This indicates that there is always some reserve capacity available from the hydro plants for spinning reserve and other ancillary services. Further, the monthly minimum and maximum capacities were the same as the Company's modeling used in Aurora which was based on the five-year average shapes. These shapes would also reflect reserve requirements.

Q. DID YOU APPLY THIS TECHNIQUE FOR ALL OF AVISTA'S HYDRO RESOURCES?

A. No. My review of logs for the Spokane resources indicates that their operation is typically much "flatter" than the Clark Fork resources. Further, the Mid-Columbia resources provide much less energy to Avista than the other hydro resources. For these reasons, I limited my hydro dispatch optimization to the Clark Fork resources. This simplifying assumption most certainly results in a conservative estimate. Finally, I made no attempt to optimize hydro dispatch for non-Avista resources. To do so might have some impact on wholesale market prices in Aurora. However, I expect any impacts of this would be minimal in relation to Avista's total power supply costs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS ISSUE?

A. I recommend that in this case the Commission accept my recommended adjustment for hydro modeling. For future cases, I recommend the Commission require the Company to develop a methodology to optimize hydro dispatch either within the Aurora model, or in an after the fact re-dispatch such as I performed.

4. Bidding Factors

Q. DO YOU AGREE WITH THE BIDDING FACTOR ADJUSTMENT PROPOSED BY MR. KALICH?

A. No. Mr. Kalich used the bidding factors to align market prices predicted by the Aurora model with actual forward curve results. While forward curves represent actual market results, they are not by themselves a perfect or always even a reliable indicator of future market prices. Indeed, a forward curve is out of date as soon as it is computed. Market prices change every hour of every trading day, and yesterday's forward curve is about as significant as yesterday's news. There is little reason to "force fit" the model results to forward curves when (as Mr. Kalich testifies) the annual difference between the results is only 4%.

Q. DOES THE FACT THAT THE AURORA MODEL FORWARD PRICES DO NOT EQUAL THE FORWARD CURVE INDICATE THERE IS SOMETHING WRONG WITH THE MODEL?

A. No. There may also be many valid reason why a forward curve would differ from the Aurora model predictions especially for purposes of setting normalized rates. Normalized rates will reflect normalized loads, fuel costs, plant availabilities, hydro conditions, etc. Actual forward curves reflect actual market knowledge of all normal and abnormal events that are expected to occur in the near future.

Further, Aurora is a fundamentals based model, while forward curves reflect not only the fundamentals of supply and demand, but also "market psychology." The latter factor can drive prices above or below levels predicted by a fundamentals based model depending on whether traders are more concerned about surplus or shortage conditions in the months ahead. Market prices, like stock prices, are driven by "greed and fear" while models reflect supply and demand. Normalized rates that may be in place for many years should not reflect ephemeral phenomena such as market psychology.

Finally, even if the discrepancy between the Aurora model predictions and the forward curve results is the result of some other type of input data problem or inaccurate modeling assumption, use of bidding factors may mask the problem and will not necessarily provide more accurate results.

For these reasons, I see no need for elevating the results of the forward curve over the Aurora model predictions by use of bidding factors. I recommend the Commission reverse the bidding factors used by Mr. Kalich, resulting in the adjustment shown on Table 1.

Q. IS THIS ISSUE ADDRESSED IN THE STIPULATION?

A. No. None of the adjustments listed in Attachment A address this issue.

5. <u>Colstrip Modeling</u>

Q. AFTER HYDRO, WHAT IS AVISTA'S MOST IMPORTANT RESOURCE?

A. Avista's 15% share of the Colstrip plant is its next most important resource considering its annual generation supply and cost.

Q. IS THE AVISTA MODELING OF COLSTRIP REALISTIC?

A. No. The Company ignores pending capacity uprates for the plant, uses unrealistic planned outage assumptions and overstated outage rates.

Q. DISCUSS THE CAPACITY UPGRADES FOR COLSTRIP.

A. In Avista's response to ICNU Data Request ("DR") No. 1.36, the Company stated: "The partners who own Colstrip 3 & 4 have plans to upgrade Colstrip 3 unit in 2006. The Company has not modeled the upgrade for this filing, nor has it included the expected capital costs associated with it." Exhibit No.___(RJF-10C) at 1. [redacted] __ at 2.

Q. DOES THIS APPEAR TO BE AN ECONOMIC CAPACITY UPGRADE?

A. Certainly. The economic analysis of this project (the Attachment to ICNU 1.36) showed a [redacted] payback, indicating the capital cost will be paid for [redacted] operation. Id. at 3.

Q. HOW SHOULD THIS UPGRADE BE MODELED IN AURORA?

A. So long as the capital costs for the project are included on a comparable basis, there is no reason not to annualize both upgrades to the start of 2006. Given the substantial economic benefit of the project, I would question the prudence of any delay in the completion of the project. Further, bids have already been received and a vendor has been recommended to the owners. These upgrades will be in effect during the likely rate effective period and should be reflected in the power cost study. Table 1 shows the impact of this adjustment on power supply expense as well as the impacts on ratebase and depreciation expense.

Q. DISCUSS THE MAINTENANCE OUTAGE MODELING USED FOR COLSTRIP.

A. The Company has assumed that the planned outages for Colstrip will occur with equal likelihood over every month of 2006. In effect, the Company has modeled Colstrip planned outages as if they were forced outages that occur at random. This is quite unrealistic because schedulers attempt to minimize cost by planning maintenance in periods where market prices and demands are low.

Q. DO YOU HAVE ANY EVIDENCE TO SUPPORT THIS CONTENTION?

A. Avista's responses to ICNU DR Nos. 4.9 and 4.10 show the actual and planned maintenance schedules for Colstrip for 2000 to 2004 and the planned schedule for 2006. Exhibit No.___(RJF-11). The data shows that the outages have nearly always been scheduled in the spring, with the majority of outages occurring in May and June.

Q. HOW DO YOU RECOMMEND THAT COLSTRIP OUTAGES BE MODELED?

A. For purposes of setting normalized rates, outages should be scheduled to coincide with periods of lowest wholesale market prices. For the 2006 study, this occurs in the months of May and June. Consequently, I model the Colstrip outages during those months. Table 1 shows the impact of this adjustment.

Q. DO YOU AGREE WITH THE COLSTRIP OUTAGE RATE ASSUMPTIONS USED IN AURORA?

A. No. The Company has used a five-year average for computing the Colstrip outage rates. However, as shown in Exhibit No.___(RJF-9), Colstrip availabilities have declined in the past several years. Based on the history of the plant, this decline appears anomalous. However, if the trend is indicative of a long-term decline in plant availability, it is a cause for concern. Colstrip Units 3 and 4 are relatively new generators, and should not be expected to show a decline in availability due to aging. Nothing in the Avista testimony justifies or even addresses the decline in Colstrip performance. The Commission should not reward the Company for a decline in the performance of its most important thermal resource.

Q. HOW DO YOU RECOMMEND THE COMMISSION MODEL COLSTRIP OUTAGE RATES?

A. To dampen the impact of recent poor performance, I recommend the Commission use a ten-year average availability for the plant. This produces a reduction to power supply costs in the amount shown in Table 1.

Q. DOES THE STIPULATION ADDRESS ANY OF THESE ISSUES RELATED TO COLSTRIP?

A. Attachment A lists a $481,000 adjustment related to "Colstrip Maintenance." The details of this adjustment are not provided in the Stipulation documents. I assume it will be explained in some detail in the Signing Parties testimony supporting the Stipulation. However, the size of this adjustment appears much too small to adequately address these issues.

6. <u>Other Power Supply Cost Issues</u>

Q. HAVE YOU IDENTIFIED ANY OTHER OUTAGE RATE DATA ISSUES IN AURORA?

A. Yes. Aurora uses "generic" data inputs for all generators in the Western Electrical Coordinating Council to provide a market-wide dispatch of power plants to derive wholesale prices. As in the case of Colstrip, the generic planned outage rate modeling is questionable. In the generic inputs, it is assumed that all power plant maintenance is scheduled during the months of March, April, May, September and October. These assumptions do not appear to be coordinated with the market price results of the model however, as low market price months such as June are assumed to have no planned outages. Further, in actual practice some planned outages do occur in other months. To address this issue, I have developed a more realistic scheduling of planned outages for the model, resulting in the adjustment shown on Table 1. As in the case of many other issues discussed above, the Stipulation is silent on this issue.

Q. DO YOU AGREE WITH AVISTA'S PROFORMA ADJUSTMENT FOR WHEELING EXPENSE RELATED TO SYSTEM SALES?

A. No. This adjustment is shown on page 87 of Mr. Johnson's workpapers, provided with the filing. Exhibit No.___(RJF-12). This adjustment is based on a five year average of this expense item. However, the figure for the year 2000 is more than double the amount of all subsequent years. The 2004 levels of this expense are only one-third of the 2000 level. I recommend exclusion of the year 2000 from the calculation as it appears unrepresentative of current conditions. This results in the adjustment shown on Table 1.

Q. DO YOU AGREE WITH THE PROFORMA ADJUSTMENT FOR THE KAISER DES CONTRACT?

A. The Company has simply failed to justify this adjustment. It appears on page 113 of Mr. Johnson's workpapers. Exhibit No.___(RJF-13C). In these workpapers, the projected 2006 level is compared to the 2004 actual. Notations on the workpapers and ICNU DR No. 4.5 indicate that the cause for the revenue reduction is a new contract with Kaiser. Id.; Exhibit No.___(RJF-14). While this appears to be a plausible explanation, the Company has not provided any workpapers showing how the 2006 figures are derived. Lacking further documentation, I recommend this adjustment be reversed, as shown on Table 1.

Q. ARE EITHER OF THE LAST TWO ADJUSTMENTS ADDRESSED IN THE STIPULATION?

A. That does not appear to be the case. While there are some transmission revenue and expense issues listed, they appear to be different issues.

Q. ATTACHMENT A TO THE STIPULATION DOES ADDRESS A NUMBER OF POWER SUPPLY ISSUES CONCERNING COYOTE SPRINGS FUEL COSTS, KETTLE FALLS FUEL COSTS, AND CERTAIN OTHER POWER SUPPLY COSTS. DO YOU AGREE WITH THESE ADJUSTMENTS?

A. Because the Stipulation does not provide workpaper support or any explanation of these adjustments, I cannot comment on these issues at this time. Again, I expect these issues will be explained more fully in the Signing Parties' testimony supporting the Stipulation.

III. ENERGY RECOVERY MECHANISM

Q. BRIEFLY EXPLAIN THE REASONS WHY THE ERM WAS IMPLEMENTED IN DOCKET NO. UE-011595.

A. The ERM was implemented as a result of a settlement between all parties to that case. At the time, Avista was suffering from serious financial setbacks due to the Western Power Crisis and poor hydro conditions. In its Order, the Commission cited the Staff memo supporting the Stipulation. The Staff memo (as quoted by the Commission in its Order in Docket No. UE-011595) discussed several circumstances that existed at the time and highlighted several benefits of the stipulation including the following:

- Resolves the uncertainty with respect to the Company's exposure to extraordinary power costs during 2000 and 2001.
- Implements an energy cost recovery mechanism, with an appropriate sharing of risk between shareholders and ratepayers, consistent with traditional rate base, rate of return regulation.
- Provides an orderly way for the Company to recognize in its financial statements the change from deferred power cost accounting to the proposed ERM.
- Provides an opportunity for the parties to review issues related to power supply recovery under the ERM in 2006.

- The Stipulation provides Avista with a reasonable opportunity to turn its financial situation around and to restore the investment community's faith in the Company.

- The ultimate goal is for Avista to regain an investment grade rating on its securities, which will translate into customer benefit.

Clearly, the ERM was implemented to resolve a severe financial situation the Company was experiencing at the time. This period of time was most certainly not "business as usual."

Q. PLEASE COMMENT ON AVISTA'S PROPOSAL TO ELIMINATE THE DEADBAND OF THE ERM AND THE STIPULATION PROPOSAL TO NARROW THE DEADBAND TO $3.0 MILLION PER YEAR.

A. These proposals are most certainly inconsistent with the circumstances and premises underlying the Stipulation in Docket No. UE-011595, and lack justification. There is no support provided with the Stipulation for narrowing the deadband, and there was very little support for eliminating the deadband in the Avista testimony. In fact, the primary justification for eliminating the deadband is found in Mr. Peterson's testimony. Mr. Peterson testifies as follows:

> The deadband was developed in conjunction with a settlement related to some fixed-price contracts that were entered into by Avista during the energy crisis of 2001 to provide natural gas for thermal generation. At the time of the settlement in May 2002, the forward price of natural gas was lower than the price in the contracts, and it was understood that, absent other changes in power supply-related costs, the Company would absorb a portion of the cost of the contracts through the deadband. The last remaining natural gas contract terminated on October 31, 2004. Therefore, this element related to the deadband no longer exists.

Exhibit No.___(RRP-1T) at 29 (Mar. 30, 2005).

This argument is unsound. Based on Mr. Peterson's testimony, it was expected the Company would absorb some of the costs of the above market contract in 2001, but that situation has now ended. However, this means that, unlike 2001, the Company will now have a *better* opportunity to recover its power costs than in the past. Consequently, Mr. Peterson's argument makes little sense.

Q. DOES MR. PETERSON OFFER ANY OTHER ARGUMENTS REGARDING THE PROPOSAL TO ELIMINATE THE DEADBAND?

A. The remainder of Mr. Peterson's limited justification concerns the volatility in power supply costs due to gas and hydro. However, this justification is questionable as well. During the power crisis and the settlement negotiations in Docket No. UE-011595, wholesale power costs appeared much more uncertain and volatile than today. Further, the hydro and gas uncertainty also existed at that time. The Commission Staff memo quoted above (which the Commission relied upon) stated the $9.0 million deadband resulted in an "appropriate sharing of risk between shareholders and ratepayers." Mr. Peterson has failed to demonstrate any significant change in circumstances since that time that would now render that sharing mechanism and deadband "inappropriate." Likewise, the Stipulation does not provide any explanation as to why a $3.0 million deadband is now appropriate.

Q. HAVE OTHER CIRCUMSTANCES RELATED TO THE COMMISSION'S APPROVAL OF THE ERM CHANGED SINCE THE STIPULATION IN DOCKET NO. UE-011595 WAS ADOPTED?

A. Yes. Two of the elements of the Stipulation discussed above were the goal of "restoring the financial community's faith" in the Company and allowing Avista the opportunity to "turn its financial situation around." Avista's financial conditions have improved substantially. As Mr. Malquist testifies: "We have been aggressively rebuilding our financial health…"[6/] and "the Company's financial performance has improved since 2001…."[7/] Mr. Malquist further testifies the Company may regain investment grade status in 2006.[8/] Because bad and worsening financial conditions were part of the circumstances that resulted in adoption of the original $9.0 million deadband, the currently improving financial conditions do not support elimination or even narrowing of the deadband. Indeed, just the opposite—they support widening of the deadband if not abandonment of the ERM.

Q. DISCUSS THE PROPOSAL TO ELIMINATE THE ERM DEADBAND IN THE CONTEXT OF ICNU'S SUPPORT FOR THE STIPULATION IN DOCKET NO. UE-011595.

A. This proposal illustrates why ICNU has a difficult time accepting proposals such as the ERM, and has been reluctant to do so in the past. While ICNU supported the ERM at a time when the Company's financial circumstances were dire, it was very concerned that "cost plus" ratemaking would not become so entrenched in the regulatory process so as to become a "way of life." Unfortunately, the Avista proposal and the subsequent narrowing of the deadband in the Stipulation does just that. It seeks to move away from the traditional concept of investors assuming the risks of operating the business, and towards the concept of socializing unfavorable outcomes. While Avista and the Signing Parties would have ratepayers absorb risks normally borne by shareholders, no rights of ownership or other compensation for these additional risks are conferred upon them. Having started down the path of "cost plus" ratemaking when times were

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6/ Exhibit No.___(MKM-1T) at 2.
7/ Id. at 3.
8/ Id.

bad, the Company and Signing Parties now seek to shift further risks onto customers even when times are improving. This is not in keeping with ICNU's understanding of the ERM when it was first implemented and ICNU strongly opposes this proposal.

Q. SHOULD THE ERM BE CONTINUED?

A. No. The ERM is not needed to allow Avista to have an opportunity to earn its allowed rate of return. Eliminating the ERM would place the responsibility for improvement of Avista's financial circumstances in the hands of management, rather than customers.

Q. IS IT ECONOMICALLY EFFICIENT FOR RATEPAYERS TO BEAR THE RISKS OF POWER COST VARIATIONS?

A. No. Ratepayers have no influence over the decisions that drive power cost variations. The overall price of power is certainly beyond the ratepayers' control. Investors, on the other hand, have the opportunity to develop a portfolio of investments to diversify their investment risks, thus eliminating exposure to the power cost risks of a single company such as Avista. As noted by Mr. Maury Galbraith of the OPUC Staff in a recent proceeding concerning power cost adjustments in Oregon, "It is much more efficient to have the financial markets diversify [Net Variable Power Costs] risk, than to allocate the risk to customers and have them bear it." Re PGE, OPUC Docket No. UE 165, Staff/100, Galbraith/9 (Feb. 14. 2005).

Q. HOW SHOULD THE COMMISSION DEAL WITH POWER COST VARIATIONS IN THE ABSENCE OF AN ERM?

A. As the Commission noted in its Order in Docket No. UE-011595, the Company has the option of filing deferral mechanisms in cases where extreme power cost variations occur. A reasonable approach for the Commission would be to allow deferrals in situations where hydro generation levels are expected to depart by more than one standard deviation from the mean. To be fair, such an approach should be required in cases where both hydro surpluses and deficits occur. By clarifying its position on this point, the process of dealing with hydro variations can be streamlined and regulatory uncertainty removed in the future.

For cases where power cost variations occur for other reasons, such as natural gas or wholesale power cost fluctuation, the Company always has the option of filing deferrals as well. The Commission has amply demonstrated in the past that it will allow such deferrals in extreme situations when circumstances warrant it.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.