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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-991606

REBUTTAL TESTIMONY OF KELLY O. NORWOOD

REPRESENTING AVISTA CORPORATION

WUTC
DOCKET NO. UE-991606
EXHIBIT # T-203
ADMIT ✓ W/D REJECT

I. INTRODUCTION/SUMMARY

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

A. My name is Kelly O. Norwood. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. Have you previously provided testimony in this proceeding?

A. Yes.

Q. Please summarize your rebuttal testimony?

A. My rebuttal testimony will address the power supply related adjustments proposed by Mr. Alan Buckley of the Commission Staff, Mr. Donald Schoenbeck of ICNU, and Mr. Jim Lazar of Public Counsel. I am sponsoring Exhibit Nos. ___ (KON-1) through ___ (KON-14), which I will introduce as I refer to them in my testimony. A table of contents for my rebuttal testimony is as follows:

A brief summary of the Company's response to the major adjustments proposed by Mr. Buckley of Commission Staff and Mr. Schoenbeck of ICNU is as follows:

Portland General Electric (PGE) Monetization Transaction

The Company's proposal in this case is to flow through to customers the revenue stream from the original PGE Capacity Sale Contract of approximately $12.1 million per year for the Washington jurisdiction (WA). Staff is recommending that the $145.0 million up-front payment associated with the PGE monetization transaction be used to offset certain expense and ratebase items, as opposed to the Company's proposal to include revenue based on the revenue stream of the original contract. The offset approach proposed by Staff would shift a significant amount of the benefits from the later years of the PGE Contract to the front. The Company does not agree with Staff's recommendation for the following primary reasons:

- The primary purpose of the PGE monetization transaction was to preserve the value of the original PGE sale contract.
- The Monetization Transaction was a financial arrangement and is considered a loan for tax purposes.
- PGE did not buy down the contract rate or buyout the contract. PGE continues to pay the same price per KW that was in the original contract.
- The monetization did not change the power delivery obligations by Avista. Avista continues to provide 150 MW of capacity under the new arrangement, and will continue to do so until December 31, 2016, the termination date of the original sales contract.
- The last two years of the original PGE Contract (2015 and 2016) were not monetized and remain in place per the original agreement.
- On a present value basis the annual amounts from the original contract that were monetized are essentially equivalent to the $145.0 million up-front payment.
- Staff's proposal represents a proposal to manage specific actions to be taken by the Company that involve financial decisions that should reside with the management of the utility.
- Staff's proposal would require an up-front write-off of $9.3 million (WA), and would reduce the Company's annual revenue requirement by approximately $11.4 million (WA).

Market Transaction Adjustment

The Company has proposed to exclude the gains and losses from short-term commercial trading activity from the ratemaking process, and reduce utility overhead costs by $306,000

(WA) related to this activity. Staff has proposed an adjustment to guarantee $3.5 million (WA) of margins annually to customers related to commercial trading activity. ICNU has proposed an adjustment to guarantee $4.2 million (WA) of margins annually to customers related to commercial trading activity. The Company does not agree with these recommendations for the following primary reasons:

- Commercial trading transactions are speculative in nature, are not dependent upon the Company's generating resources, and are unrelated to transactions to serve retail load or long-term wholesale obligations. Shareholder capital is placed at risk through the commercial transactions, and the gains and losses should be the responsibility of shareholders.
- Mr. Buckley has employed a methodology that is seriously flawed and will not provide a reasonable estimate of margins from commercial trading activity.
- ICNU has used a methodology that significantly overstates the estimated margins from commercial trading activity.
- Both parties have failed to recognize the costs associated with commercial trading transactions that should be netted against any estimate of margins.

<u>60 Year vs 40 Year Water Record</u>

The Company has proposed to use the actual streamflow conditions for the 60-year period 1929 to 1988 to represent average water conditions for hydroelectric generation. Staff has recommended the use of the 40-year period 1949 to 1988 based on a rolling 40-year average methodology. Staff's recommendation reduces the Company's annual revenue requirement by approximately $4.0 million (WA). The Company does not agree with this recommendation for the following primary reasons:

- The theory with the 40-year rolling average methodology is that the errors in random data in the near-term will be offset with errors in the opposite direction in the long-term. Because there are non-random variables involved in the normalization of hydroelectric generation, that will not remain constant over time, the offsets will not occur with the rolling average methodology as intended.
- The lower cumulative error related to the random data is dependent on the same methodology being applied for a very long period of time. There can be no assurance that this same methodology will be consistently applied in the long term.

- A review of the actual historical streamflow data shows that the 1949-88 40-year period recommended by Staff includes more years with water conditions above-average than below-average.
- We are not aware of any studies in the Northwest region that use the 1949-88 40-year period recommended by Staff.
- If the Commission rejects the use of the Company's proposed 60-year period, it should also reject Staff's proposed 40-year period, and adopt the 1939-1988 50-year period to normalize streamflow conditions for ratemaking purposes. This would result in a reduction in the Company's originally filed revenue requirement of approximately $2.4 million (WA).

Capacity Purchases

The Company has proposed expenses associated with short-term capacity purchases of $0.6 million (WA). Staff has recommended that all of the $0.6 million expense for short-term capacity purchases be eliminated in this case. The Company does not agree with this recommendation for the following primary reasons:

- Historically, the Company has consistently relied upon a combination of both short-term and long-term capacity resources to serve its firm load obligations.
- The Company has provided information that supports both the need for these short-term capacity purchases, as well as the reasonableness of the cost of the short-term capacity purchases.

Dispatch Credit

The Company is a net purchaser of short-term energy. In this case the Company has proposed an average short-term energy purchase price of $22.32/MWh for the proforma rate year. Staff has proposed to reduce the average short-term purchase price from the $22.32/MWh proposed by the Company to $18.83/MWh. Staff's recommendation reduces the Company's revenue requirement by approximately $1.1 million (WA). The Company does not agree with this recommendation for the following primary reasons:

- A comparison of both the Company's ($22.32) and Mr. Buckley's ($18.83) proposed short-term purchase prices with the current and expected future market prices shows that both of these proposals are well below where they should be.
- The Company's average short-term purchase price for 1999 was $27.54/MWh.
- At May 30, 2000 the short-term firm market prices at the Mid-Columbia and at the California-Oregon Border (COB), for the next year, are well over $30.00/MWh.
- In the recently completed Centralia sale docket there was a significant amount of discussion regarding wholesale market prices. For the 2000 to 2001 period the prices used by the various parties to the case ranged from approximately $26.00/MWh to $30.00/MWh.
- In Mr. Buckley's own testimony regarding the Potlatch Purchase Adjustment he uses a rate of $29.75/MWh, which he refers to as a "more representative market rate" for the 15 month period October 2000 through December 2001.
- Based on current and expected market prices for the near future, the Company has already significantly understated its power costs in this rate case. Any adjustment to market prices through this Dispatch Credit adjustment should be an increase in market prices, not a decrease as proposed by Staff.

Sale of Centralia/Centralia Replacement Power Costs

The Centralia generating project was sold to TECWA Power, Inc effective May 5, 2000. In this case the Company has proposed to remove the ownership and operating costs of Centralia, and to include the replacement power costs associated with the TransAlta replacement power purchase. In addition, the Company has proposed ratemaking treatment in this case related to the customer share of the gain on the sale of Centralia. Staff and ICNU have proposed to flow the gain on the sale of Centralia through to customers, but deny recovery of the replacement power costs associated with Centralia. These recommendations reduce the Company's revenue requirement by approximately $4.1 million (WA). The Company does not agree with these recommendations for the following primary reasons:

- The Company has demonstrated both the need for the replacement resource, and the reasonableness of the cost of the resource.
- It would be unreasonable for customers to enjoy the benefits of the gain on the sale of Centralia, and to require the Company to absorb the costs of the power to replace the resource.

II. PGE MONETIZATION TRANSACTION

Q Please begin with the first issue related to the Portland General Electric (PGE) Monetization Transaction. Do you have any opening comments related to this issue?

A Yes. There were a number of strong statements made by Mr. Buckley of the Commission Staff and Mr. Schoenbeck representing ICNU, that appeared to call into question the intentions of the Company regarding the PGE Monetization Transaction, especially statements made by Mr. Schoenbeck. Specifically, Mr. Schoenbeck makes accusations related to the Company concealing[1] information, and making a "direct effort to mislead this Commission."[2] Mr. Schoenbeck even makes a reference to honesty.[3] These statements and accusations made by Mr. Schoenbeck are uncalled for and are, in fact, unsubstantiated.

I want to make it clear that there was no intention on the part of the Company to "conceal" or hide anything from the Commission or the other parties to this case related to the PGE Monetization Transaction. I believe the facts provided below will bear that out.

The facts will show that there was no attempt on the Company's part to conceal the PGE Monetization Transaction from the Commission or the other parties, and that there was no attempt by the Company to retain benefits for shareholders at the expense of the Company's customers. In fact, the Company made public disclosure of this transaction and fully explained its planned proposal for retail ratemaking treatment related to this transaction in a filing with the FERC over 19 months ago.

Q What is the Company's proposal in this case related to the PGE Contract?

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[1] Schoenbeck, Page 4, Line 15.
[2] Schoenbeck, Page 14, Lines 17-18.
[3] Schoenbeck, Page 15, Line 10.

A The Company's proposal in this case is to flow through to customers the revenue stream from the original PGE Capacity Sale Contract. The proforma revenue for the rate year is $18.0 million.

In December 1998, the Company monetized or received an up-front payment of $145.0 million related to the future revenues from the PGE Contract for the period 1999 - 2014. Because the PGE Monetization Transaction was a financial arrangement to preserve the original revenue stream, the revenue stream proposed by the Company in this case for ratemaking purposes is that original revenue stream.

Q What is Staff's recommendation in this case related to the PGE Contract?

A Staff is recommending that the $145.0 million up-front payment associated with the monetization transaction be used to offset certain expense and ratebase items. The offset approach proposed by Staff would shift a significant amount of the benefits from the later years of the PGE Contract to the front (next several years), which would substantially reduce the benefits to customers in the later years.

Q Does the Company agree with Staff's recommendation?

A No. As I will explain in my testimony, the monetization transaction was a financial arrangement to preserve the original revenue stream. In fact, the transaction is considered a loan for tax purposes. PGE did not buy down the contract rate or buyout the contract. PGE continues to pay the same price per KW that was in the original contract. Avista continues to provide the same 150 MW of capacity over the term of the original agreement. The last two years of the original PGE Contract (2015 and 2016) were not monetized and remain in place per the original agreement. Staff's proposal represents a proposal to micro-manage the utility in proposing actions to be taken by the Company that involve financial decisions that should reside with the management of the utility. Furthermore, Staff's proposal would result in a write-off to the Company of $9.3 million. Staff provides no sound basis for its proposal to accelerate the PGE benefits, and its proposal to accelerate these benefits should be rejected.

Q Please briefly explain the original PGE Contract.

A In the original agreement dated June 26, 1992, Exhibit No. 170 in this Docket, the Company entered into a long-term contract to sell capacity to Portland General Electric (PGE). In the Agreement, Avista sold 50 megawatts (MW) of capacity to PGE from November 1992 through October 1994, and 150 MW from November 1994 through the end of the Agreement, December 31, 2016. The price each year for capacity was fixed by contract in the Agreement. The revenue from this original contract for the period 1998 through 2016 was as follows (in millions of dollars):

1998	$18.7	2005	$18.2	2011	$18.8
1999	$18.4	2006	$18.3	2012	$18.9
2000	$18.1	2007	$18.4	2013	$19.0
2001	$17.9	2008	$18.5	2014	$19.1
2002	$17.9	2009	$18.6	2015	$19.2
2003	$18.0	2010	$18.7	2016	$19.3
2004	$18.1				

The 176 MW Rathdrum simple-cycle combustion turbines were placed into service by the Company in January 1995 to serve the Company's system capacity needs, including the 150 MW PGE Capacity Sale. The annual costs associated with these units, as shown on Page 55 of Mr. Buckley's Exhibit No. ___ (APB-5), are approximately $9 million per year. A comparison of the $18 million/year revenues from the PGE Contract with the $9 million/year costs for the Rathdrum turbines shows a tremendous benefit for the Company and its customers of approximately $9 million/year.

In addition, the 176 MW of capacity from the Rathdrum turbines provide an additional 26 MW more capacity than the 150 MW PGE capacity sale, which results in significant additional value over and above the $9 million/year.

Q Please explain the change to the PGE Agreement that occurred effective January 1, 1999.

A The original PGE capacity sale Agreement included capacity sale prices of approximately $10 per kilowatt per month (KW-month) over the term of the Agreement ($10.00/KW-month x 150,000 KW x 12 months = $18.0 million). In 1998 these sale prices were well above market. PGE was acquired by Enron in 1997. PGE was pursuing the sale of generating assets, and there was an increasing probability of electric restructuring in Oregon. Avista viewed these changes as creating increased uncertainty related to receiving the full value of the above-market sales contract for the term of the agreement. In the later part of 1998 Avista negotiated an arrangement to "monetize" a major portion of the PGE Sales Contract, through an up-front payment.

Through the monetization transaction, the Company received an up-front payment of $145.0 million. The up-front payment covered contract revenues from January 1999 through December 2014. The capacity sales price in the original contract for the period January 1999 through December 2014 (16 years) was reduced from approximately $10/KW-month to a fixed price of $1.00.KW-month, or from $18.0 million to $1.8 million per year. The revenues to Avista for years 2015 and 2016, however, will be per the original capacity sale contract at approximately $10/KW-month.

Q Did the monetization transaction result in a negative impact to customers?

A No. The transaction locked in the value of the revenue stream from the original PGE Contract, and secured the benefits from this contract through year 2014.

Q Why did the Company propose in this case that the revenue stream from the original PGE Contract be included for ratemaking purposes in this case?

A There were several reasons. First, the primary purpose of the PGE monetization transaction was to preserve the value of the original PGE sale contract. The receipt of the up-front payment allowed the Company to capture that value now, and spread it back out over the monetization period (1999 through 2014). Capturing the value up-front reduced the risk that some of the value of the above-market contract would be lost at some point in the future.

Second, the Monetization Transaction was a financial arrangement and is considered a loan for tax purposes. PGE did not buy down the contract rate or buyout the contract. PGE continues to pay the same price per KW that was in the original contract. The monetization did not change the power delivery obligations by Avista. Avista continues to provide 150 MW of capacity under the new arrangement, and will continue to do so until December 31, 2016, the termination date of the original sales contract. The last two years of the original PGE Contract (2015 and 2016) were not monetized and remain in place per the original agreement. The risk associated with the future revenue stream was shifted away from Avista Utilities and its customers through this loan arrangement.

Third, the Company filed an application with the Federal Energy Regulatory Commission (FERC), on September 8, 1998, for approval of the contract assignment. In this filing the Company explained the planned retail ratemaking treatment for this transaction as follows:

> Further, both the accounting and ratemaking treatment of the proposed disposition in this Application will assure that all ratepayers, including retail ratepayers, are held harmless by the assignment. Under WWP's accounting and ratemaking proposal for the

> assignment, <u>the benefits of the Capacity Contract will continue to be passed on to customers in such a manner that the revenue requirement reduction from the assignment proposal equals the revenue requirement reduction from the existing Capacity Contract.</u>
>
> Specifically, WWP intends to record an amortization of a portion of the lump sum payment received to Account 447.74 (power sales) and an appropriate portion to Account 447.71 (transmission) through the year 2016. Revenue from the matching sale of capacity to EPMI discussed above of approximately $1.00/KW-month will also be recorded monthly in Accounts 447.74. <u>In addition to the amortization "revenues" to be recorded monthly in Accounts 447.74 and 447.71, WWP intends to reflect an additional revenue credit for ratemaking purposes so that the total booked "revenue" in the accounts reflected for ratemaking purposes is equivalent to the revenue that would have occurred absent the assignment of the contract</u>. (underscores added)

Thus, over 19 months ago, in September 1998, the Company explained that, under the new monetization arrangement, the revenues that would be proposed for retail ratemaking purposes would be equal to the revenue stream under the original contract.

A Notice of Filing was issued by the FERC on September 11, 1998 regarding the Company's filing. A copy of FERC's Notice as well as excerpts of pages from this filing are provided in Exhibit No. ___ (KON-1).

Fourth, the Company monetized the difference between the original contract rate of approximately $10.00/KW-month and the capacity price in the new arrangement of $1.00/KW-month, or approximately $16.2 million per year for 16 years (1999 – 2014). The present value of $16.2 million per year for 16 years at a discount rate of 7.83% is equal to $145.0 million. While some could differ on the appropriate discount rate to use, <u>on a present value basis the annual amounts from the original contract that were monetized are essentially equivalent to the $145.0 million up-front payment.</u>

This becomes a "pay-me-now" or "pay-me-later" issue. If customers were to receive more money up-front than proposed by the Company, they would receive less later. Because the

PGE Monetization Transaction was a financial arrangement to preserve the original revenue stream, the revenue stream proposed by the Company in this case for ratemaking purposes is that original revenue stream.

Q Did the Company record any "gain" to shareholders related to the PGE Monetization Transaction?

A No. The Company did not record a gain on its books for shareholders related to the PGE Monetization Transaction. The revenues associated with the up-front payment were deferred, and are being amortized over the 16-year monetization period 1999 – 2014.

Q On Page 16 of his testimony Mr. Buckley refers to a Company memo that "identified a potential for a benefit net present value of $32 million." Is there a $32 million benefit that is in some way not being reflected in this filing?

A No. The memo referred to by Mr. Buckley is dated May 11, 1998. This was in the early stages of developing the monetization arrangement which did not occur until December 1998. The assumptions in the memo were different than the actual terms that were finally agreed to in December, e.g., the assumed up-front payment in the memo was higher than the actual payment received under the terms of the agreement.

As I explained above, the present value of the $16.2 million per year revenue stream that was monetized for 16 years, at a discount rate of 7.83% is equal to $145.0 million. On a present value basis the annual amounts from the original contract that were monetized are essentially equivalent to the $145.0 million up-front payment.

Q Do you have any final comments regarding the ratemaking treatment proposed by the Company in this case related to the PGE Capacity Sale Agreement?

A Yes. The proposal filed by the Company in this case to continue to flow through to customers revenue equal to the revenue stream under the original PGE Contract is fully consistent with what Avista had committed to and had publicly disclosed in its filing with FERC over 19 months ago. A reference to the transaction was also included in the Company's 1998 10K and the notes to the Company's 1998 Annual Report, which were issued over a year ago. The Company did not attempt to conceal or hide information. Prior to filing this case, the Company had already publicly disclosed the transaction on three different occasions, in three different documents, including the specific retail ratemaking treatment that would be proposed related to the transaction.

The Company did not record a gain on its books for shareholders related to this transaction. The fact is the Company did not attempt to gain value for shareholders at the expense of customers through this transaction. Through a simple phone call or written request for information Mr. Schoenbeck could have been fully informed as to the circumstances surrounding the Company's PGE rate treatment proposal. There was no phone call or request for information by Mr. Schoenbeck. Instead, Mr. Schoenbeck drew his own conclusions without knowing the facts, and made statements and accusations in his testimony that are unsubstantiated and uncalled for.

Mr. Schoenbeck's recommendation related to disallowance of recovery of the regulatory fees in Washington, as well as his recommendation to deny the Company's request for a 25 basis point common equity adder should both be rejected. To penalize the Company would not be appropriate or reasonable.

Q Moving on to the specific ratemaking proposals in this case related to the PGE Contract revenue, Staff has proposed that the deferred PGE revenues be used to offset certain expense and ratebase items. Please explain why you do not agree with Staff's proposal?

A Staff's proposal should be rejected for several reasons. First, as has already been explained, the PGE Monetization Transaction was a financial arrangement to preserve the original revenue stream related to the original PGE Contract. The Company's proposal in this case continues to flow this original revenue stream through to customers. This revenue stream now, however, has a lower risk of being reduced in the future, because of the monetization transaction.

Second, Staff's proposal represents a proposal to micro-manage the utility in proposing actions to be taken by the Company that involve financial decisions that should reside with the management of the utility. For example, Staff has recommended that the Company spend approximately $55 million of the proceeds to buy out the balance of the Rathdrum Lease. This recommendation was made without any analysis of the costs or benefits associated with buying out the Lease. The Company's question and Staff's response to Avista Data Request No. 5 are as follows:

> Request:
> Provide any analysis or any other written material prepared by Staff related to Staff's proposal for Avista to buy out the Rathdrum lease.
>
> Response:
> With the exception of what is contained in Mr. Buckley's testimony and in the supporting workpapers, Staff did not prepare any analyses or other written material related to the proposal for Avista to buy out the Rathdrum lease.

These types of financial decisions should reside with the management of the utility.

Third, Staff has provided no sound basis for shifting a major portion of the benefits from the PGE Contract forward to the next 3 to 5 years. The PGE Monetization Transaction was a financial arrangement to preserve the original revenue stream. The revenue stream used for ratemaking purposes should be that original revenue stream.

Finally, certain components of the Staff's proposal are unreasonable. For example, the monetization transaction was executed in December 1998. Beginning in January 1999 the Company's revenues from the PGE Contract were reduced by approximately $16.2 million/year, from the approximate $18.0 million/year level to $1.8 million/year. In addition, the Company began amortizing the deferred revenue balance in January 1999 at an annualized rate of $8.865 million/year. The amortization of this revenue is necessary to partially offset the Company's revenue reduction of $16.2 million/year.

Staff's proposal is to credit to customers $143.4 million beginning October 1, 2000. The actual balance of deferred revenue at October 1, 2000 will be $129.5 million, because of the amortization that began in January 1999. The calculation of this balance is shown in Exhibit No. ___ (KON-2). Staff's proposal would require a write-off by the Company of $9.3 million (($143.4 - $129.5) x 66.99% WA share). The Company's decision to enter into the original PGE Contract has provided tremendous benefits for the Company's customers. A recommendation that requires the Company to write-off $9.3 million related to a transaction designed to preserve these benefits would be unreasonable and should be rejected.

Q If the Commission were to decide to shift the PGE benefits forward, what changes should be made to Staff's proposal?

A As a foundation in responding to this question, the Company's proposed rate making treatment related to the PGE Contract, and the proposed treatment by Staff are as shown below:

	Use of Deferred Revenue Balance (System 100%)	Approximate Annual Revenue Requirement[4] Increase/(Decrease) (WA 66.99%)
Avista Proposal:		
Original PGE Contract Revenue		**($12,058,000)**
Staff Proposal:		
PGE Contract Revenue (At $1.00/KW-Month)		($1,206,000)
Buyout Rathdrum Lease/Eliminate Lease Expense	($55,277,777)	($3,856,000)
Write-off WPI Contract Buyout/Eliminate Amortization	($5,046,868)	($796,000)
Reduce Potlatch Purchase Cost through 12/31/2001	($11,411,452)	(5,695,000)
Write-off DSM Balance/Eliminate Amortization	($31,957,000)	($6,128,000)
Amortize $26,600,000 over 16 years (ratebase reduction)	($39,707,000)	($5,785,000)
Total Staff Proposal	**($143,400,097)**	**($23,466,000)**
Change in Revenue Requirement (Staff vs Avista)		($11,408,000)

Staff's proposal uses $143.4 million of PGE deferred revenues to offset the ratebase and expense items shown above. Staff's proposal would reduce the Company's revenue requirement by approximately $11.4 million as compared to that proposed by the Company.

The original PGE revenue stream proposed by the Company, and an estimate of the annual benefits proposed by Staff for the next 16 years are illustrated in graphic form on Exhibit No. ___ (KON-3). As shown on this Exhibit, Staff's proposal would give Avista's customers more of the PGE Contract benefits up-front and less in later years.

[4] These figures are estimates. Final revenue requirement figures will be dependent upon other issues such as cost of capital, etc.

Q With this information as a foundation, now please explain the adjustments that should be made to Staff's proposal if the Commission were to decide to give customers more of the PGE benefits now and less later.

A If the Commission were to decide to front-load the PGE benefits, the following adjustments should be made:

1. The balance of PGE deferred revenues should be taken as of the beginning of the rate year, i.e., October 1, 2000. That amount is $129,486,000 (Exhibit No. ___ (KON-2)) as opposed to the $143,400,000 proposed by Staff.
2. The PGE deferred revenues should first be used to offset the Company's Ice Storm costs (if the Commission does not adopt Mr. McKenzie's proposal related to Ice Storm costs) and the $2.5 million Nez Perce Settlement payment.
3. The remaining balance of the PGE deferred revenues, after the offsets, should be credited to Avista's customers over a 14.25 year period as opposed to the 16 year period proposed by Staff.

Q Please explain the Company's first adjustment related to the deferred revenue balance at October 1, 2000.

A As explained earlier, beginning in January 1999 the Company's revenues from the PGE Contract were reduced by approximately $16.2 million/year. In addition, the Company began amortizing the deferred revenue balance in January 1999 at an annualized rate of $8.865 million/year (Exhibit No. ___ (KON-2)). The amortization of this revenue, as well as the time value of money on the up-front payment, is necessary to offset the Company's revenue reduction of $16.2 million/year. On Pages 18 and 19 of Mr. Buckley's testimony he discusses giving the Company the benefit of the "interest on the net cash balance" for the 21 month period January

1999 through September 2000. Mr. Buckley appears to have overlooked the $16.2 million reduction in revenues in his analysis.

The actual balance of deferred revenue at October 1, 2000 will be $129.5 million, not $143.4 million as proposed by Staff. Staff's proposal would require a write-off by the Company of $9.3 million (($143.4 - $129.5) x 66.99% WA share). The Company should not be required to incur a write-off related to this transaction that was made to preserve significant benefits for the Company and its customers.

Furthermore, Mr. Parvinen proposed two separate adjustments in his testimony to reflect unamortized balances at the beginning of what Staff referred to as the rate year, i.e, October 1, 2000. The proposed adjustments were for the Company's Investment in WNP-3 Exchange Power and the balance of the Company's investment in DSM. In explaining his adjustments, Mr. Parvinen argued that there are no additions being made to the balances – only an amortization of the balance – and therefore, the balance at the beginning of the rate year would be known. The Company has not objected to these proposed adjustments.

Similarly, the PGE deferred revenue balance is a regulatory asset. There are no additions being made to the balance – only an amortization of the balance – and therefore, the balance at the beginning of the rate year is known. Therefore, the PGE deferred balance of $129,486,000 at October 1, 2000 should be used in the calculation of any offsets.

Mr. Schoenbeck's recommendations related to the PGE transaction also do not reflect the amortization that began in January 1999, and the need for this amortization and the interest value on the up-front payment, to compensate the Company for the $16.2 million reduction in revenue beginning in January 1999. Mr. Schoenbeck's recommendation related to PGE should be rejected.

Q Please explain the Company's second adjustment to Staff's PGE Offset approach related to Ice Storm costs and the $2.5 million Nez Perce Settlement payment.

A As Mr. Falkner explained in his testimony, the Ice Storm costs were the result of an unusual weather event in the Company's service area. These costs were a necessary business expense for Avista to restore service to its customers following the Ice Storm, and it would be reasonable to provide recovery of these costs.

As explained earlier, the Company's decision to enter into the PGE Contract has provided a significant benefit. Staff has proposed to use the PGE deferred revenues to "clean up" certain expense and ratebase items, e.g., write-off the balance of the WPI PURPA contract buyout, write-off the DSM balance, etc. The significant benefit generated by the Company related to the PGE Contract provides an excellent avenue to provide recovery of the Ice Storm costs for the Company.

The Company is not proposing to recover the Ice Storm costs more than once. If the Commission chooses to use the PGE deferred revenues to cover the Ice Storm costs, the proposed adjustment by Mr. McKenzie to use a portion of the gain on the sale of Centralia to offset the Ice Storm costs should be eliminated, and the Ice Storm costs included in Mr. Falkner's Injuries and Damages Adjustment should be removed.

The total Ice Storm costs are $15,326,416 on a system basis, with $12,284,817 assigned to the Washington jurisdiction. If the PGE deferred revenues are used to cover the Ice Storm costs, removing the Ice Storm costs from the Injuries and Damages Adjustment would reduce the Company's revenue requirement by $2,047,470.

If the Commission rejects the Company's offset proposal related to Ice Storm, the Company requests that the Commission award shareholders 15% of the PGE deferred revenue balance at October 1, 2000, to provide shareholders with a meaningful benefit for creating this significant value for customers. The remaining 85% would accrue to customers through the proposed offsets. It appears that Mr. Buckley intended to provide shareholders with a portion of the benefits from the PGE Contract in his discussion on Pages 18 and 19, and in the Staff's response to Avista's Data Request No. 47 attached as Exhibit No. ___ (KON-4) (although his specific proposal would result in a write-off for shareholders, as explained earlier).

Granting the Company 15% of the balance at October 1, 2000 would provide the Company's shareholders a tangible benefit from the PGE Contract, and send a message to the Company that there can be financial benefits to shareholders as well as customers from creating this kind of significant benefit. Fifteen percent of the balance of PGE deferred revenues at October 1, 2000, for the Washington jurisdiction, would be $13,011,000.

With regard to the Nez Perce Settlement payment, the Company made a one time up-front payment to the Nez Perce Tribe of $2,500,000 and began amortizing the payment over 45 years beginning January 1999, per Mr. Falkner's testimony. If the Commission adopts the offset approach, the Company proposes to "clean up" this one-time item along with the Ice Storm costs, and some of the other offsets proposed by Staff. The balance at October 1, 2000 would be $2,402,800 on a system basis, and $1,609,600 for the Washington jurisdiction. Eliminating this balance with the PGE deferred revenues would reduce the Company's proposed revenue requirement by $37,217.

Q And finally, please explain the Company's third adjustment related to a 14.25 year amortization period.

A The PGE deferred revenue balance is related to the monetization of revenues from the PGE Contract for the 16 year period January 1999 through December 2014. Any amortization of the PGE deferred revenue balance should not extend beyond December 2014. The remaining term from the beginning of the rate year, October 1, 2000, is 14 years and three months.

Q What would be the resulting change in revenue requirement by incorporating the Company's adjustments to Staff's PGE revenue offset proposal?

A The table below compares the Company's originally proposed treatment in this case for the PGE Contract, and Staff's proposed PGE revenue offset approach including the Company's adjustments explained above.

	Use of Deferred Revenue Balance (System 100%)	Approximate Annual Revenue Requirement Increase/(Decrease) (WA 66.99%)
Avista Original Proposal:		
Original PGE Contract Revenue		**($12,058,000)**
Staff Offset Approach – Including Avista's Adjustments		
PGE Contract Revenue (At $1.00/KW-Month)		($1,206,000)
Buyout Rathdrum Lease/Eliminate Lease Expense	($55,277,777)	($3,856,000)
Write-off WPI Contract Buyout/Eliminate Amortization	($5,046,868)	($796,000)
Reduce Potlatch Purchase Cost through 12/31/2001	($11,411,452)	(5,695,000)
Write-off DSM Balance/Eliminate Amortization	($31,957,000)	($6,128,000)
Offset Ice Storm Costs	($15,326,416)	($2,047,000)
Write-off Nez Perce Payment	($2,402,800)	($37,000)
Amortize $5,401,000 over 14.25 years	($8,063,000)	($1,212,000)
Total Staff Proposal	**($129,485,313)**	**($20,977,000)**
Change in Revenue Requirement (Offset Approach vs Avista Filing)		($8,919,000)

The Offset approach, as adjusted by the Company, would reduce the Company's originally filed revenue requirement by approximately $8,919,000. Again the Offset approach would give Avista's customers more of the PGE Contract benefits up-front and less in later years.

Staff's proposed revenue offset approach should be rejected for the reasons explained above. In the event the Commission adopts the offset approach, however, the offsets should include the adjustments made by the Company.

III. MARKET TRANSACTION ADJUSTMENT

Q What is the Company's proposal in this case related to Market Transactions?

A The Company has proposed to exclude the gains and losses from short-term commercial trading activity (Market Transactions) from the ratemaking process. These transactions are speculative in nature, are not related to the operation of the Company's system resources or in serving retail load, among other reasons explained in my direct testimony. The Company has proposed to reduce the utility overhead costs charged to customers by $305,880 (WA share) annually, to reflect an allocation of overhead costs to this activity.

Q What is Staff's recommendation in this case related to Market Transactions?

A Staff has proposed an adjustment to guarantee $3,450,000 (WA share) of margins annually to customers related to commercial trading activity, and has eliminated the Company's proposed overhead cost reduction of $305,880.

Q Does the Company agree with Staff's recommended Market Transaction Adjustment?

A No. Mr. Buckley has attempted to estimate what he would consider to be a "normalized value" of commercial trading margins to be credited to retail customers by the Company. As I will explain below, the methodology that Mr. Buckley has chosen is seriously flawed and cannot be relied upon to provide even a rough estimate of margins from commercial trading activity. In his analysis, Mr. Buckley subtracts the same proforma Short-Term Sales and

Short-Term Purchase values from the actual sales and purchase values for each of the years 1996 through 1999. This methodology produces results that are completely unreliable and unusable.

Q Please explain.

A In my explanation I will refer to the specific numbers that Mr. Buckley used in his analysis. The analysis prepared by Mr. Buckley is duplicated below for ease of reference:

1996	Short-Term Sales		Short-Term Purchases
Actual Short-Term Totals	$103,329,504		$102,391,079
Less Staff Dispatch Model	**$4,853,700**		**$19,733,500**
Subtotal	$98,475,804		$82,657,579
Market Transaction Net Revenue		$15,818,225	

1997	Short-Term Sales		Short-Term Purchases
Actual Short-Term Totals	$191,202,936		$188,739,726
Less Staff Dispatch Model	**$4,853,700**		**$19,733,500**
Subtotal	$186,349,236		$169,006,226
Market Transaction Net Revenue		$17,343,010	

1998	Short-Term Sales		Short-Term Purchases
Actual Short-Term Totals	$354,264,000		$361,880,000
Less Staff Dispatch Model	**$4,853,700**		**$19,733,500**
Subtotal	$349,410,300		$342,146,500
Market Transaction Net Revenue		$7,263,800	

1999	Short-Term Sales		Short-Term Purchases
Actual Short-Term Totals	$387,228,688		$396,957,645
Less Staff Dispatch Model	**$4,853,700**		**$19,733,500**
Subtotal	$382,374,988		$377,224,145
Market Transaction Net Revenue		$5,150,843	

The figures labeled as Market Transaction Net Revenue represent Mr. Buckley's estimates of margins from commercial trading for each of the respective years. The problem with Mr. Buckley's analysis is that he has subtracted the identical Short-Term Sales and Short-Term Purchases figures each year from the Actual Short-Term Totals. These figures are shown in the boxes in the table above, i.e., $4,853,700 for Short-Term (ST) Sales and $19,733,500 for Short-Term (ST) Purchases.

The ST Sales ($4,853,700) and ST Purchases ($19,733,500) figures were determined based on Staff's Dispatch Model run in this proceeding, which included load obligations and resources available to Avista for the proforma rate year July 1, 2000 through June 30, 2001.

The ST Sales figure from the Dispatch Model represents the extent to which the Company would sell short-term surplus power from its system resources during that rate year into the short-term market. The ST Purchases figure from the Dispatch Model represents the extent to which the Company would rely on the short-term market purchases during the rate year to serve firm load obligations. Mr. Buckley failed to recognize the importance of the relationship of the ST Sales and ST Purchases figures in his analysis.

Q Please continue.

A The Staff's Dispatch Model run shows that on a net basis, the Company is a net purchaser from the short-term power market equal to $14,879,800 (purchases of $19,733,500 and sales of $4,853,700). The energy obligations (loads) for Avista and the energy resources available to the Company from the Dispatch Model run are as shown below:

	Staff Model Run Average Megawatts (Loads)/Resources
Firm Retail Load Obligations	(993)
Firm Wholesale Contract Obligations	(376)
Firm Contract Rights	363
Hydroelectric Generation	577
Thermal Generation	352
Net Surplus/(Deficiency)	(77)

The Dispatch Model run shows a deficiency, which means the Company must purchase from the short-term market during the rate year to serve its firm energy load obligations.

Q Why is the relationship of the ST Sales and ST Purchases figures so important in Mr. Buckley's estimates of margins from commercial trading?

A The relationship of the ST Sales of $4,853,700 and ST Purchases $19,733,500, resulting in net purchases of $14,879,800, is <u>unique to the load and resource balance</u> <u>for the proforma rate year July 1, 2000 through June 30, 2001</u>. Any change in the load/resource balance would change the relationship of the ST Sales and ST Purchases. For example, if a firm contract right of 100 average megawatts (aMW) were to be added to Staff's Dispatch Model run, it would result in the Company being 23 aMW surplus rather than 77 aMW deficient as shown below:

	Staff Original Model Run Average Megawatts (Loads)/Resources	Staff Run With Addl. 100 aMW Firm Rights Average Megawatts (Loads)/Resources
Firm Retail Load Obligations	(993)	(993)
Firm Wholesale Contract Obligations	(376)	(376)
Firm Contract Rights	363	**463**
Hydroelectric Generation	577	577
Thermal Generation	352	352
Net Surplus/(Deficiency)	(77)	23

This new load/resource balance would result in a very different relationship for ST Sales and ST Purchases. Rerunning Mr. Buckley's Dispatch Model run with the additional 100 aMW Contract Right results in ST Sales of $9,844,800 and ST Purchases of $6,990,100, which would make the Company a net seller of short-term energy equal to $2,854,700 instead of a net purchaser of $14,879,800. This is a swing in the ST Sales/ST Purchases relationship of $17,734,500.

The point to all of this is that the load/resource balance for each year is different, and will result in a different relationship for the ST Sales and ST Purchases. To the extent that any of the following items are different each year, it will result in a different ST Sales/ST Purchases relationship:

Firm Retail Load Obligations
Firm Wholesale Contract Obligations
Firm Contract Rights
Hydroelectric Generation
Thermal Generation
Short-Term Market Prices

Q How does this affect Mr. Buckley's analysis?

A As an example, we know that Hydroelectric Generation for the Company in 1997 was 695 aMW, which was one of the best water years on record. Plugging this known level of hydroelectric generation into the load/resource (L/R) balance used by Staff to develop its trading margin calculation for 1997 shows that the Company would have been a net seller of short-term energy of 41 aMW, all other things being equal, and not a net purchaser of 77 aMW:

	Staff Load/Resource Balance Average Megawatts (Loads)/Resources	Staff L/R Balance With 1997 Hydro Generation Average Megawatts (Loads)/Resources
Firm Retail Load Obligations	(993)	(993)
Firm Wholesale Contract Obligations	(376)	(376)
Firm Contract Rights	363	363
Hydroelectric Generation	577	**695**
Thermal Generation	352	352
Net Surplus/(Deficiency)	(77)	41

The actual ST Sales/ST Purchases relationship for 1997 would have been substantially different than the $14,879,800 net purchase condition used by Mr. Buckley in his analysis. The net difference in the deficiency of (77) aMW and the surplus of 41 aMW is 118 aMW. If this additional energy were priced out at the average short-term market price of $19.34/MWh (from Mr. Buckley's Dispatch Model run, Exhibit No. ___ (ABP-2)) it would result in a swing in the ST Sales/ST Purchases relationship of $19,991,400 (118 aMW x 8760 hours x $19.34/MWh). This would show that the Company was a net seller of $5,111,600 as opposed to a purchaser of $14,879,800, all other things being equal. Plugging this adjustment into Mr. Buckley's analysis for 1997 yields the following results:

Staff's Original Analysis

1997	Short-Term Sales	Short-Term Purchases	
Actual Short-Term Totals	$191,202,936	$188,739,726	Net Purchaser
Less Staff Dispatch Model	**$4,853,700**	**$19,733,500**	← **$14,879,800**
Subtotal	$186,349,236	$169,006,226	
Market Transaction Net Revenue	$17,343,010		

Adjusted to Reflect Actual Hydroelectric Generation

1997	Short-Term Sales	Short-Term Purchases	
Actual Short-Term Totals	$191,202,936	$188,739,726	Net Seller
Less Staff Dispatch Model	**$8,851,980**	**$3,740,380**	← **$5,111,600**[5]
Subtotal	$182,350,956	$184,999,346	
Market Transaction Net Revenue	($2,648,390)		

This single adjustment based on a known level of hydroelectric generation for 1997 would cause Mr. Buckley's methodology to actually show a Market Transaction Net Revenue loss of ($2,648,390). We also know that the retail loads, firm contract rights and obligations, thermal generation, and the short-term market prices in 1997 were different than that included in the proforma rate year Dispatch Model run used by Mr. Buckley. We also know that there are major differences in some or all of these items for 1996, 1998 and 1999 which would have a significant affect on the analysis developed by Mr. Buckley.

[5] The adjustment of $19,991,400 was split between Sales and Purchases based on the ratio of total Sales and Purchases in Mr. Buckley's original analysis. The way the adjustment is split between the two does

This is a fatal flaw in Mr. Buckley's analysis. There is no possible way using Mr. Buckley's methodology to determine a reasonable estimate of margins from commercial trading activity. There are too many variables that have a major impact on the net difference between ST Sales and ST Purchases to be able to isolate them without a detailed analysis of each of the variables. The methodology chosen by Mr. Buckley in no way provides any indication of the trading margins that occurred in those years.

Mr. Buckley has proposed a $5.15 million (system) adjustment related to this issue. Mr. Buckley's proposed Market Transaction adjustment should be completely rejected. It is disturbing that Staff would propose such a methodology that violates very basic fundamental analysis related to these power supply revenues and expenses.

Q Are there any other major short-comings in Mr. Buckley's analysis?

A Yes. Mr. Buckley also failed to recognize the costs associated with commercial trading transactions that should be netted against any estimate of margins. These include, but are not limited to, broker fees, FERC fees and write-offs.

Q Mr. Schoenbeck recommended a revenue requirement reduction of $6.9 million (system) related to commercial trading activity. Do you agree with this adjustment?

A No. Mr. Schoenbeck has "cherry picked" a single year (1998) from the data provided by the Company in response to Staff Data Request No. 314. He has also ignored all of the transaction costs associated with commercial trading.

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not affect the final result since the net change in the Sales/Purchases relationship is a total of $19,991,400 in any event.

Q If an estimate of commercial trading margins were to be made based on the information contained in the Company's response to Staff Data Request No. 314, together with all other known trading related revenues and expenses, what would be the result?

A The Company prepared an estimate of trading margins for 1998 and 1999 based on these informal records and all other known trading-related revenues and expenses. The analysis is included in Exhibit No. ____ (KON-5), and a summary is provided below:

	1998	1999
Gross Margin From Trading Transactions	$4,920,656	$2,033,165
Less: Broker Fees	($347,943)	($336,150)
FERC Fees	($561,543)	($528,489)
Write-Offs/Losses	($1,098,472)	-
Net Commercial Trading Margins	$2,912,698	$1,168,526
Net Margins - Two Year Average	$2,040,612	
Net Margins - Washington Share at 66.99%	$1,367,006	
50%/50% Sharing Between Shareholders/Customers	$683,503	

A scenario with a 50%/50% sharing of these Net Margins between shareholders and customers would result in $683,503/year to customers and $683,503/year to shareholders.

Q Is the Company proposing that an estimate of trading margins be used in any way in determining the Company's revenue requirement in this proceeding?

A No. As the Company explained in response to Staff Data Request No. 314, these records are not official records of the Company, do not include all of the related transactions and transaction costs, and are not relied upon by the Company for accounting purposes.

Furthermore, as I explained in my direct testimony beginning on Page 20, commercial transactions are not dependent upon the Company's generating resources, and are unrelated to transactions to serve retail load or long-term wholesale obligations. Shareholder capital is placed at risk through the commercial transactions, and the gains and losses should be the responsibility of shareholders.

In my direct testimony, on Page 27, I proposed a reduction in overhead costs for Washington customers of $305,880 annually to assign a portion of these costs to the commercial trading activity.

Q Did the Idaho Public Utilities Commission address the commercial trading issue in Avista's recent rate case in Idaho?

A Yes. The IPUC Staff's position regarding commercial trading was summarized on Page 15 of IPUC Order No. 28097, dated July 29, 1999, in Case No. WWP-E-98-11 as follows:

> "It is Staff's belief that the speculative trading engaged in by the Company is a discretionary activity that is risky and not always profitable. If ratepayers are allowed to share in the profits, they would also be subject to the losses if they should occur. Staff believes that the Company's retail customers should not be subject to such risks."

The Idaho Commission, in its findings on Page 16 of the Order, stated as follows:

> "Recognizing that the Resource Optimization department of the Company does engage in some level of speculative transactions not otherwise associated with the operation of Company resources or serving retail load, we find it appropriate to make an A&G related adjustment."

The Idaho Commission rejected an intervenor proposal to calculate trading margins involving the difference between gross short-term sales and gross short-term purchases, similar to that proposed by Mr. Buckley.

In its Order, the Idaho Commission adopted an A&G cost reduction related to commercial trading equal to $876,370 on a system basis, or $283,944 for the Idaho jurisdiction. The Washington jurisdictional share of the same $876,370 system number, at 66.99%, would be $587,080 per year.

Q On Page 22 of his testimony, Mr. Schoenbeck states that if the Commission adopts the Company's proposal to exclude commercial trading transactions, then FERC fees should be reduced by $279,280 on a Washington basis. Do you agree with this recommendation?

A Yes.

IV. 60-YEAR VS 40-YEAR WATER RECORD

Q What has the Company proposed in this case related to the water record to use in normalizing hydroelectric generation for ratemaking purposes?

A The Company has proposed to use the actual streamflow conditions for the 60-year period 1929 to 1988 to represent average water conditions for hydroelectric generation. These average water conditions are used to normalize hydroelectric generation for ratemaking purposes.

Q What has Staff recommended in this case related to the water record?

A Staff has recommended the use of the 40-year period 1949 to 1988 to represent average water conditions. This recommendation is based on a rolling 40-year average methodology. As the water record data is updated every ten years, under the rolling average methodology, the first ten years are dropped and the next ten years are added (the ten year increments are explained on Page 10 of my direct testimony).

Q On Pages 7 through 10 of Mr. Buckley's testimony he contends that the Company has not provided "clear and convincing" evidence that the Company's proposed 60-year water record is superior to the 40-year water record. Do you agree?

A No. I believe that a careful review of the evidence will show that Staff's 40-year rolling average proposal will not provide the best estimate of average water conditions for ratemaking purposes. The evidence includes a review of the actual historical water year data, the water record used by others in the industry, and the flaws in the rolling average methodology. This evidence was presented by the Company in its direct testimony, in the material contained in Exhibit Nos. 160 and 161, and in responses to questions from Chairwoman Showalter during hearings in this proceeding.

Page 18 of the Commission's Third Supplemental Order in Cause No. U-85-36, dated April 4, 1986, states as follows:

> "The Commission's decision does not mean that the Commission will use a rolling 40 years for all future cases. The Commission will evaluate alternatives proposed in future cases."

We believe it is especially important that the evidence related to this issue be carefully evaluated for several reasons. First, an adjustment by Staff of the magnitude of $5.9 million (as is the case here), warrants careful consideration. Second, none of the existing Commissioners were on the Commission when this issue was last addressed for Avista in 1986, and two of the existing Commissioners were not on the Commission when the issue was addressed in the Puget Sound Energy case in 1992. Third, an additional 10 years of data (1979-1988) have been added to the water record since the issue was last addressed for Avista and for Puget Sound Energy.

Q What part of the evidence presented by the Company do you believe provides clear and convincing arguments, contrary to statements made by Mr. Buckley?

A The evidence presented by the Company can be categorized into three general areas:

1. Information related to the short-comings of the rolling 40-year average methodology.
2. Information related to the streamflow record used by other parties in the Pacific Northwest.
3. Information related to the historical streamflow data itself.

Q Please explain the information related to the short-comings of the 40-year rolling average methodology.

A The 40-year rolling average methodology was initially adopted based on the expectation that it would result in a reduction in the <u>long-term cumulative error</u> in normalizing streamflow conditions for ratemaking purposes. There are fatal flaws to this methodology, however, that have been raised and discussed, but that I believe have not been fully understood. They include the following:

1. There are both random and non-random variables involved in normalizing hydroelectric generation, and the resulting power supply costs, for ratemaking purposes. Because there are non-random variables involved, the errors will not offset each other over time as intended.
2. Because the methodology is completely dependent on a consistent application over a long period of time, it would require future Commissions for multiple decades to consistently apply the same methodology, irrespective of any changes that may occur in the electric industry or in the future ratemaking process.

Q Please explain the short-coming related to the non-random variables.

A In Cause No. U-85-36 Mr. Winterfeld presented analysis that demonstrated mathematically that a rolling average methodology would provide a lower cumulative error in the long-term <u>using random data</u>. Random data was used because studies have not found any proven trends or patterns to the precipitation data and the resulting streamflow each year.

The theory with the rolling average methodology is that the <u>errors in the near-term will be offset with errors in the opposite direction in the long-term future</u>. The fatal flaw with the methodology is that we are not dealing solely with random data. The streamflow data is only one component in the adjustment to normalize hydroelectric generation for ratemaking purposes. The normalization adjustment involves the following components:

1. A period of historical streamflow data to use in the determination of average streamflow conditions.
2. Avista's hydroelectric projects in place today (both owned and by contract).
3. The current operation of reservoirs in the region.
4. Short-term market prices at which the surplus energy or energy deficiencies related to the hydroelectric generation are priced.

Although the streamflow data may be random, some of the other variables are not. For example, the hydroelectric generation that the Company receives under contract from the Mid-Columbia PUDs (Grant, Chelan and Douglas) is also normalized through this adjustment. These contracts expire in 2005/2009, 2011 and 2018, respectively. There is no assurance that the Company will be able to renew these contracts or will have similar rights to power if they are renewed.

It would be unreasonable to apply a methodology that relies on errors put in place today to be offset at some point in the long-term future, when these Mid-Columbia contracts are set to expire.

Furthermore, to the extent that there are long-term or permanent changes to reservoir operations, that affect either the timing or amount of generation from the available streamflow, these changes will also affect the offsets that are <u>intended</u> to occur in the future. We have already seen major changes in reservoir operations related to the Biological Opinion implemented in 1995, and the recently completed relicensing of the Noxon Rapids and Cabinet Gorge projects on the Clark Fork River. Other upgrades and modifications to either the equipment or the operation of the projects will also affect the offsets that are intended to occur in the future under the rolling average methodology.

If all other variables were held constant, then statistics tell us that errors today related to a rolling average of random data will be offset at some point in the future. We know, however, that these other variables will not remain constant, and therefore, the offsets will not occur in the future as intended.

Q Did prior Commission Orders recognize these non-random variables?

A No. The discussion in prior Commission Order's related to this issue addressed only the analysis performed on the random data. I do not believe the serious flaw in the methodology related to the non-random variables used in the normalization adjustment was fully understood at the time the methodology was adopted. This problem was raised in testimony included in Exhibit 161.

On Page 17 of the Commission's Third Supplemental Order, dated April 4, 1986, in Cause No. U-85-36 the Commission stated that:

> The Commission Staff contended that the Company's method was more reliable for predicting prospective average water conditions, but was not the best method for enhancing long-term accuracy while reducing year-to-year variation. (underscore added)

The reference to "while reducing year-to-year variation" is related to a comparison of the 40-year rolling average to a 30-, 20-, or 10-year rolling average, and not to the method proposed by the Company. The Company's proposed method is "more reliable for predicting prospective average water conditions," and will also provide a lower "year-to-year variation" in the normalized values, than the rolling 40-year average methodology. Because the non-random variables involved in the normalization process will not remain constant in the long-term, the offsets will not occur with the rolling average methodology as intended.

Q Please explain the short-coming related to the consistent application of the rolling average methodology over a long period of time.

A As stated earlier, the lower cumulative error related to the random data is dependent on the same methodology being applied for a very long period of time. The water year data is updated once every ten years, therefore, the use of a less reliable estimate under the rolling average methodology would be in place for at least a ten year period. Although it is possible that the error could be fully offset during the next ten-year period, it is not likely. It may take 30, 40, or 50 years or more to achieve this theoretically lower cumulative error that is intended by this methodology.

This normalization adjustment affects short-term sales revenues, short-term purchase expenses, and thermal fuel costs. With the rapid changes in the industry including the increased volatility of the wholesale market and continuing efforts to restructure the industry, it may be essential at some point to change the way these revenues and expenses are treated for ratemaking purposes. The methodology proposed by the Company provides the more reliable estimate of average water conditions for ratemaking purposes and is not dependent in any way on future events.

It would be unreasonable to attempt to bind future Commissions to this same 40-year rolling average methodology, for decades, in order to pursue the offsets that are necessary to achieve this theoretically lower long-term cumulative error.

Q Please explain the evidence related to the historical streamflow data.

A Page 1 of Exhibit No. ___ (KON-6) shows historical streamflow data for the Columbia River, as measured at The Dalles, Oregon, for the period 1879 through 1992. Each bar on this chart represents the percentage difference in the actual streamflow for that year as compared to the average streamflow for the 114-year period 1879 – 1992. For example, the streamflow at The Dalles for 1879 was 6% above the 114 year average.

This data is important in that it is based on actual measured streamflow on the Columbia River for the 114-year period 1879 - 1992. The Dalles is located on the lower end of the Columbia River and the streamflow measured there includes flows from Canadian reservoirs, the Clark Fork and Spokane Rivers, where Avista's owned hydroelectric generation resides, the Snake River, and many other tributaries. This is an industry accepted measuring point for flows on the Columbia River. The streamflow measurements at The Dalles, therefore, provide a good indicator of the precipitation, and ultimately the streamflow, that occurred in the region for this 114-year historical period.

In choosing a period of water years to serve as an average condition for ratemaking purposes, it is very important to look at the actual streamflow data available to determine whether there are any obvious problems with the period of years chosen. In this case, the Company has proposed the 60-year period 1929-88 and Staff has proposed the 40-year period from 1949-1988.

Page 2 of Exhibit No. ___ (KON-6) presents the same data as Page 1, but a smoothing technique, using a 5-year average, has been applied to smooth out some of the year-to-year variability. For example, the value shown on Page 2 for 1981 is the average for years 1979-1983, the value for 1982 is the average for 1980-1984 and so on.

Studies have concluded that there are no trends or cycles to the water record data. However, as shown on this bar chart, for this 114-year period there are clearly some extended periods of above-average water conditions, and some extended periods of below-average water conditions. In choosing a period of water years from this data, it is important that the period selected include a reasonable balance of above-average water conditions and below-average conditions.

In the Puget Sound Energy Docket No. UE-920433 one party to the case recommended that the Commission use the average from the 30-year period 1949-1978 to represent normal water conditions for ratemaking purposes. A visual look at this period on the bar chart on Page 2, without doing any analysis, clearly shows that this 30-year period includes water conditions that were consistently above-average, and would not be a reasonable period to choose to represent average water conditions for ratemaking purposes.

With regard to the 1949-1988 40-year period proposed by Staff in this case, it is also apparent from a visual look at the bar chart on Page 2 that this period includes more years with water conditions above-average than below-average.

The bar chart on Page 3 of Exhibit No. ___ (KON-6) shows modeled hydroelectric generation for Avista's projects on the Clark Fork and Spokane Rivers for 1929-1978 and actual generation for 1979-93. These generation figures are based on the actual streamflows that occurred for these Rivers during these 65 years. Streamflow records for the Clark Fork River, where the majority of Avista's hydroelectric generation resides, are not available prior to September 1928. Page 4 of this Exhibit includes the same data as Page 3, but with the same 5-year average smoothing technique applied that was used for the Columbia River data. It is also apparent from a visual look at the bar chart on Page 4 that the 1949-1988 40-year period proposed by Staff in this case, includes more years with water conditions above-average than below-average.

The following table provides a summary comparison of the average cubic feet per second (CFS) flow on the Columbia River for the specific water records proposed by the Company and Staff, as well as the 50-year period 1939-1988. These figures are based on the data used to develop the bar chart on Page 2 of Exhibit No. ___ (KON-6):

	Columbia River Average Flow (Cubic Feet/Second)
114 Years 1879-1992	199,986
40 Years 1949-1988 – Staff Proposal	202,915
60 Years 1929-1988 – Company Proposal	194,472
50 Years 1939-1988	198,882

This analysis shows that the 40-year average proposed by Staff is above the 114-year average, and the 60-year average proposed by the Company is below the 114-year average. This analysis taken alone would suggest that the 50-year period 1939-1988 would provide the better estimate of normal streamflow conditions for ratemaking purposes, than either of the 40-year average or the 60-year average. Although the differences in these numbers appear small, the period of years chosen for ratemaking purposes makes a significant difference in revenue requirement, as evidenced by Staff's $5.9 million proposed adjustment.

If the Commission rejects the use of the Company's proposed 60-year period, it should also reject Staff's proposed 40-year period, and adopt the 1939-1988 50-year period to normalize streamflow conditions for ratemaking purposes.

Q What historical period of water years do other parties in the region use in analysis involving hydroelectric generation?

A The historical water years used by others in the region that I am aware of are as follows:

1. The Northwest Power Planning Council (NWPPC) used the 1929-1978 50-year period in developing its Northwest Power Supply Adequacy/Reliability Study, Phase One Report dated March 2000.
2. The Northwest Power Pool (NWPP) uses the 1929-1988 60-year period to calculate the down-stream benefits from the release of water from upstream storage reservoirs (Headwater Benefits Study).
3. The NWPP uses the 1929-1988 60-year period to determine the "critical period" that is used in regional planning studies. The critical period occurs during the 1936-37 operating year.
4. The Bonneville Power Administration (BPA) uses the 1929-1978 50-year period for ratemaking purposes.
5. The BPA uses the 1929-1978 50-year period in developing its White Book Study. This study is used by BPA to develop its loads and resources balance, and is used in relation to some power contract provisions.
6. BPA uses the 1929-1988 60-year period for "what-if" studies related to future operations.

I am not aware of any regional studies that use the rolling average methodology or the 40-year period proposed by Staff in this case.

I believe that a review of the evidence, including the actual historical water year data, the water record used by others in the industry, and the flaws in the rolling average methodology clearly shows that Staff's 40-year rolling average proposal will not provide the best estimate of average water conditions for ratemaking purposes. Staff's proposal should be rejected.

Q What would be the change from the Company's proposed power costs related to the various water record alternatives that you have discussed above?

A The following table provides a comparison of what the change in power costs would be from the various water record alternatives:

	Change in Power Costs from Avista's 1929-88 60-Year Proposal	
	System Increase/(Decrease)	Washington Increase/(Decrease)
1949-88 40-Year Study		
Proposed by Staff	($5,900,000)	($3,952,410)
1939-88 50-Year Study		
From review of the historical water year data above	($3,610,000)	($2,418,000)
1929-78 50-Year Study		
Used by BPA and NWPPC	($137,000)	($92,000)
1929-1988 60-Year Study		
Used by BPA and NWPP	No Change	No Change

Work sheets supporting these figures are provided as Exhibit No. ___ (KON-7). As I stated earlier, if the Commission rejects the use of the Company's proposed 60-year period, it should also reject Staff's proposed 40-year period, and adopt the 1939-1988 50-year period to normalize streamflow conditions for ratemaking purposes.

V. CAPACITY PURCHASES

Q What has the Company proposed in this case regarding short-term Capacity Purchases?

A The Company has proposed expenses associated with short-term capacity purchases of $955,000. This is based on the actual cost of short-term capacity purchases during the 1998 test period.

Q What has Staff recommended in this case regarding short-term Capacity Purchases?

A Staff has recommended that all of the $955,000 expense for short-term capacity purchases be eliminated in this case. Mr. Buckley asserts that the Company has not provided documentation to support the proposed short-term Capacity Purchase expenses.

Q Do you agree with Staff's recommendation?

A No. The Company has provided information that supports both the need for these short-term capacity purchases, as well as the reasonableness of the cost of the short-term capacity purchases. Historically, the Company has consistently relied upon a <u>combination of short-term and long-term capacity resources</u> to serve its firm load obligations, which the Company has explained in its Least Cost Planning report attached as Exhibit No. ___ (KON-14) (Page 2 of the Appendices). The use of a portfolio of both short-term and long-term resources results in lower costs to customers over time. If the costs of these short-term capacity resources are denied for ratemaking purposes, then the Company would be forced to acquire only long-term resources, which would result in higher costs to customers.

Q Please explain the supporting information provided by the Company.

A In response to Staff Data Request No. 61, the Company provided a copy of the Tabulation of Firm Requirements & Resources (Load/Resource Tabulation) from its last Least

Cost Plan report. This Tabulation from the Report is attached as Page 1 of Exhibit No. ___ (KON-8). The Tabulation, on Line 53, shows a need for capacity resources of 256 megawatts (MW) in year 2000, and 120 MW in year 2001. Furthermore, this Load/Resource Tabulation includes a retail load reduction (Redistributed Load - Line 2) under the assumption that the Company would lose retail load related to electric restructuring. This has not occurred and is not expected to occur in the near future. Removing this Redistributed Load reduction from the Load/Resource Tabulation results in capacity deficiencies of 356 MW in 2000 and 250 MW in 2001, as shown on Page 1 of Exhibit No. ___ (KON-8).

The Load/Resource Tabulation includes all of the Company's <u>long-term</u> firm capacity and energy resources and firm load obligations. Any near-term deficiencies are met with short-term purchases.

This Load/Resource Tabulation is specifically prepared to determine the capacity and energy resource needs for the Company. This document is supported by literally hundreds of pages of studies and analysis, and hundreds of hours of resource planning efforts by the Company. Drafts of this document and the supporting analysis are shared with outside parties, including the Commission Staff, through the Least Cost Planning process prior to finalizing the document. In the years prior to the Least Cost Planning process, this Load/Resource Tabulation was developed by the Company to use in determining its needs for both capacity and energy resources.

Through the Least Cost Planning process, as well as through this general rate case process, Staff and other parties have had ample opportunity to ask questions regarding the assumptions that go into developing this Load/Resource Tabulation. There have been no questions from Staff in this case regarding the need for capacity resources shown on this document.

In describing the documentation provided by the Company in support of the Capacity Purchases on Page 26 of his testimony, Mr. Buckley failed to even identify this document that was provided by the Company.

Furthermore, a Draft Load/Resource Tabulation dated November 10, 1999, attached as Page 2 of Exhibit No. ___ (KON-8), was distributed to the parties at the Company's Least Cost Planning meeting on November 18, 1999. Although Staff did not attend this particular meeting, Staff indicated in response to Data Request No. 68 that "Company personnel mailed meeting handouts and meeting minutes to Staff after the meeting." This November 10, 1999 Tabulation, on Line 53, shows a need for capacity resources of 437 MW in year 2000, and 337 MW in year 2001. Staff should be familiar with these Load/Resource Tabulation documents and fully informed as to the Company's loads and resources situation.

Documents provided in response to Staff Data Request No. 61 show that the Company consistently purchases November - February four-month capacity products, as well as year-around twelve-month products. Using six months as a reasonable weighted average, the Company's proposed short-term capacity purchase expense of $955,000 for 337 MW of capacity results in a cost of $0.47per KW-month ($955,000 / 337,000 / 6). This is a very reasonable cost to customers for firm capacity for the proforma rate year. If the Company were to not rely on short-term capacity purchases for a portion of its total capacity requirements, the purchase of long-term firm capacity would result in a much higher cost to customers.

Q On Page 26, Line 20, Mr. Buckley makes reference to historical data provided by the Company in support of the Capacity Purchases expense. Are there other power supply revenue or expense items that rely on historical data in developing normalized amounts for ratemaking purposes?

A Yes, there are several. An example is the OASIS Non-firm and Short-term Firm Wheeling Revenue shown on Line 121 of Exhibit No. 152. This revenue item in Account 456 includes revenue from other parties that purchase short-term transmission service from the Company through OASIS. Although we know that there will be some revenue for this item each year, we do not know exactly how much other parties will schedule in future years. The Company has consistently used a five-year average of historical revenues as the means to normalize revenues for this item. The work paper showing the calculation of this five-year average is provided on Page 1 of Exhibit No. ___ (KON-9). Staff took no exception to this adjustment in this case.

Similarly, for the short-term capacity purchases we know that the Company will purchase some level of short-term capacity each year to meet its firm load obligations. The Load/Resource Tabulations discussed above clearly show a need for these purchases.

The Company proposed to use the 1998 actual short-term capacity purchases as the normalized amount in this case. The five-year average of short-term capacity purchase expenses was provided to Staff in response to Staff Data Request No. 61, and is attached as Page 2 of Exhibit No. ___ (KON-9). The 1998 total of $955,000 is approximately the same as the five-year average of $935,313. The Company would not object to the use of the five-year average figure for this case. Staff's proposal, however, to remove the total amount should be rejected.

Q On Page 26, beginning on Line 23, Mr. Buckley states: "In addition, after removing almost all short-term sales and purchase amounts from the test year, the Company proposes to maintain capacity purchases at levels that no doubt supported the removed amounts." (underscore added) Do you agree with this statement?

A No. Mr. Buckley appears to be suggesting that the short-term capacity purchases are made to support commercial trading transactions. These short-term capacity purchases are not made to support commercial trading transactions. As I have already explained above, the Company uses a combination of long-term and short-term capacity resources to meet firm load obligations. The Load/Resource Tabulations clearly show a need for these short-term capacity purchases to meet firm obligations.

Mr. Buckley has provided no analysis or direct factual evidence to support such a statement.

Q On Page 27, Line 5, Mr. Buckley asserts that the Company "has provided no analyses that address the ability of its own system (i.e., the Clark Fork River Projects or the Rathdrum CT) to meet its capacity requirements." Do you agree?

A No. The Load/Resource Tabulations discussed above include a breakdown of the firm resources available to the Company to meet capacity obligations. These resources include the Company's hydroelectric resources and the Rathdrum CT.

Q On Page 27 of Mr. Buckley's testimony beginning on Line 8 and continuing to Line 2 of Page 28, he discusses possible "double counting" of capacity purchase expenses if Staff's Market Transaction adjustment is adopted by the Commission. Do you agree with this reason to exclude these costs?

A No. As I explained above, these short-term capacity purchases are not made to support commercial trading transactions, and are necessary to serve firm load obligations. Mr. Buckley's decision to include these costs in his Market Transaction analysis is his own choosing, and does not mean that they are related in any way. Furthermore, as I have already explained, the methodology used by Mr. Buckley in his Market Transaction adjustment is seriously flawed.

Mr. Buckley has provided no sound factual basis to exclude these expenses from this case, and his adjustment should be rejected.

VI. DISPATCH CREDIT

Q What has the Company proposed in this case regarding the Dispatch Credit issue?

A The Dispatch Credit adjustment proposed by Mr. Buckley is simply an adjustment to the average market prices proposed by the Company in this case for short-term energy purchases and short-term energy sales. These prices are determined by the Company using the Dispatch Simulation Model. In this case the Company has proposed an average short-term energy purchase price of $22.32/MWh and an average short-term energy sales price of $17.43/MWh (calculated from Exhibit No. 155).

Q What has Staff recommended in this case related to the Dispatch Credit adjustment?

A Staff has proposed to reduce the average short-term purchase price from the $22.32/MWh proposed by the Company to $18.83/MWh, and to decrease the short-term sales price from $17.43/MWh to $17.03/MWh. The methodology employed by Staff involved adjustments related to the flexibility of the Company's hydroelectric system to shape energy between heavy-load and light-load hours.

Q Do you agree with Staff's recommendation?

A Absolutely not. Even though the Dispatch Model is not an hourly model, the market prices developed from the Dispatch Model are developed to reflect a weighted average of market prices for each month of the study, including the flexibility of the Company's hydroelectric system and heavy load and light load pricing. After the Dispatch Model study is completed, the resulting prices are compared with the actual historical market prices experienced by the Company, as well as current market price conditions and expected future market conditions to test for reasonableness.

As I will explain below, a comparison of both the Company's ($22.32) and Mr. Buckley's ($18.83) proposed short-term purchase prices with the current and expected future market prices shows that both of these proposals are well below where they should be.

The Company is a net purchaser of short-term energy. As I will show below, the Company has already significantly understated its revenue requirement by using a short-term purchase price of $22.32/MWh. This price is well below the current and expected future market prices. Mr. Buckley's adjustment would further reduce the Company's revenue requirement, based on an unreasonably low short-term purchase price. His adjustment is inappropriate and should be rejected.

Q Please further explain Mr. Buckley's proposed adjustment and why the Company does not agree with it.

A Mr. Buckley used the following data from Staff's Dispatch Model run (from Exhibit ___ APB-2) in developing his Dispatch Credit proposal:

Table 1 – Staff Dispatch Model Run Results

	Short-Term Purchases	Short-Term Sales	Net Purchases
MWh	972,400	297,900	674,500
Monthly Average Price/MWh	$20.29	$16.29	
Dollars ($000s)	$19,733	$4,854	$14,879

The Company is generally surplus during the two or three months of spring runoff and deficient during the other typically higher priced months, which is why the average sales price is lower than the average purchase price.

In developing his adjustment, Mr. Buckley broke down the purchase and sale energy into heavy-load and light-load hours (based on 16 hours/day heavy load and 8 hours/day light load), and assumed a $4.4/MWh differential between heavy-load and light-load hours. Table 1 above, therefore, was broken down as follows:

Table 2 – Staff's Dispatch Model Run Split Into Heavy Load/Light Load Hours

	Short-Term Purchases	Short-Term Sales	Net Purchases
MWh – Heavy Load 2/3	648,270	198,601	449,669
MWh – Light Load 1/3	324,130	99,299	224,831
MWh – Total	**972,400**	**297,900**	**674,500**
Average Price/MWh – Heavy Load	$21.76	$17.76	
Average Price/MWh – Light Load	$17.36	$13.36	
Monthly Average Price	**$20.29**	**$16.29**	
Dollars ($000s) – Heavy Load	$14,106	$3,527	$10,579
Dollars ($000s) – Light Load	$5,627	$1,327	$4,300
Dollars ($000s) – Total	**$19,733**	**$4,854**	**$14,879**

At this point in Mr. Buckley's analysis no numbers have changed for ratemaking purposes. The Total MWh, the Monthly Average Market Prices, and the Total Dollars for Table 2 are the same as in Table 1.

The final step in Mr. Buckley's analysis is to move 50% of the purchases in heavy-load hours to light-load hours, and 50% of the sales from light-load hours to heavy-load hours as shown below. Mr. Buckley's basis for this shift is the flexibility in the Company's hydroelectric resources to shift energy between heavy load and light load hours.

Table 3 – Shift MWh Between Heavy Load and Light Load Hours

	Short-Term Purchases	Short-Term Sales	Net Purchases
MWh – Heavy Load	324,135	248,250	75,885
MWh – Light Load	648,265	49,650	598,615
MWh – Total	972,400	297,900	674,500
Average Price/MWh – Heavy Load	$21.76	$17.76	
Average Price/MWh – Light Load	$17.36	$13.36	
Monthly Average Price	**$18.83**	**$17.03**	
Dollars ($000s) – Heavy Load	$7,053	$4,409	$2,644
Dollars ($000s) – Light Load	$11,254	$663	$10,591
Dollars ($000s) – Total	**$18,307**	**$5,072**	**$13,235**
Less: Staff Original Dispatch Model Run	$19,733	$4,854	$14,879
Staff Proposed Dispatch Credit	($1,426)	$218	($1,644)

Notice in Table 3 that the "MWh - Total" purchases and sales are the same as in Tables 1 and 2. Mr. Buckley's proposed Dispatch Credit adjustment is simply a method to reduce the Monthly Average Market Price for short-term purchases, and increase the average price for short-term sales, as shown in the comparison of Table 2 and Table 3.

Irrespective of whether the Dispatch Model analysis is prepared using an hourly dispatch of resources into an hourly market, or a monthly dispatch into a monthly market, <u>the modeled results must be compared with current and expected future market price conditions to assess whether the market prices from the model results are reasonable</u>.

Q Are Mr. Buckley's proposed short-term market prices reasonable?

A No. The market prices that Mr. Buckley is proposing for both short-term purchases and short-term sales are far too low. The Company is in a net deficit (purchasing) position. Mr. Buckley is suggesting that the Company will be able to purchase short-term firm energy during the rate year (October 2000 through September 2001) at an average price of $18.83/MWh.

Wholesale market prices have been steadily increasing over the past several years. The Company's average short-term purchase prices for 1996 through 1999 are shown on Page 1 of Exhibit No. ___ (KON-10). These prices start at $12.74/MWh in 1996 and increase steadily to $27.54/MWh in 1999. Not only have the average short-term market prices been increasing, there has also been a sharp increase in the volatility in short-term market prices. Pages 2 through 4 of Exhibit No. ___ (KON-10) include graphs of the daily heavy load and light load prescheduled electric prices at the Mid-Columbia for 1998, 1999, and year-to-date 2000. These graphs show a sharp increase in volatility for this year. Real-time (hour-to-hour) pricing for this period would show an even more dramatic increase in volatility. Real-time prices at the Mid-Columbia during May 2000 rose to over $700/MWh.

Furthermore, at May 30, 2000 the short-term firm market prices at the Mid-Columbia and at the California-Oregon Border (COB) were as follows:

	$/MWh			
	Mid-Columbia		COB	
Month	Heavy Load	Light Load	Heavy Load	Light Load
Jul 00	$85.00	$43.00	$93.00	$43.75
Aug 00	$85.00	$43.00	$93.00	$43.75
Sep 00	$85.00	$43.00	$93.00	$43.75
Oct 00	$59.50	$39.75	$61.25	$42.25
Nov 00	$59.50	$39.75	$61.25	$42.25
Dec 00	$59.50	$39.75	$61.25	$42.25

	$/MWh			
	Mid-Columbia		COB	
Month	Heavy Load	Light Load	Heavy Load	Light Load
Jan 01	$44.00	Not Available	$44.50	Not Available
Feb 01	$44.00	Not Available	$44.50	Not Available
Mar 01	$44.00	Not Available	$44.50	Not Available
Apr 01	$37.25	Not Available	$37.50	Not Available
May 01	$37.25	Not Available	$37.50	Not Available
Jun 01	$37.25	Not Available	$37.50	Not Available
Jul 01	$74.00	Not Available	$82.00	Not Available
Aug 01	$74.00	Not Available	$82.00	Not Available
Sep 01	$74.00	Not Available	$82.00	Not Available

All of these prices, even during light load hours, are at or above $40.00/MWh, and are significantly above the $18.83/MWh proposed by Mr. Buckley.

In addition, in the recently completed Centralia sale docket there was a significant amount of discussion regarding wholesale market prices. For the 2000 to 2001 period the prices used by the various parties to the case ranged from approximately $26.00/MWh to $30.00/MWh.

In Mr. Buckley's own testimony regarding the Potlatch Purchase Adjustment he uses a rate of $29.7525/MWh, which he refers to as a "more representative market rate." He proposes this market rate for the 15 month period October 2000 through December 2001, which is very similar to the rate year proposed by Staff (October 2000 through September 2001).

The Company is a net purchaser of short-term energy. All of these current and future market prices are well above Mr. Buckley's proposed short-term purchase price of $18.83/MWh. Any adjustment to the short-term market prices through this Dispatch Credit adjustment should be <u>an increase in market prices, not a decrease</u> as proposed by Staff.

Q What is the effect on the Company with regard to this increase in market prices?

A The Company is in a net deficit (purchasing) position of approximately 1,000,000 MWh annually (Exhibit No. T-151, P. 21). Therefore, for every $1.00/MWh increase in the short-term market price, it increases the power costs of the Company by approximately $1,000,000 on an annual basis.

Mr. Buckley has recommended a short-term market price of $18.83/MWh for the proforma rate year. If market prices for the proforma rate year are equal to the 1999 price of $27.54/MWh, the impact to the Company would be an increase in power costs of approximately $9 million on an annual basis, that would not be recovered by the Company.

This illustrates the exposure that the Company has to changes in short-term market prices. The importance of the Company's proposed Power Cost Adjustment (PCA) mechanism is even more apparent given the recent increases in market prices and the increased volatility.

Based on current and expected market prices for the near future, the Company has already <u>significantly understated its power costs</u>. Any further reduction in power costs using Staff's proposed Dispatch Credit would be unreasonable and should be rejected.

Q On Page 31, Line 14, Mr. Buckley recommends that "the Commission encourage the Company to investigate power supply model options that can better reflect the actual operations of the Company's resources." Do you have any comments on this recommendation?

A Yes. The Company is currently developing an hourly dispatch model that the Company plans to use for future ratemaking purposes.

VII. SALE OF CENTRALIA/CENTRALIA REPLACEMENT POWER COSTS

Q What is the Company's proposal in this case regarding Centralia?

A The Centralia generating project was sold to TECWA Power, Inc effective May 5, 2000. In this case the Company has proposed to remove the ownership and operating costs of Centralia, and to include the replacement power costs associated with the TransAlta replacement power purchase. This replacement power contract is attached as Pages 7 - 11 of confidential Exhibit No. C___ (KON-C11).

In addition, the Company, through Mr. McKenzie, has proposed ratemaking treatment in this case related to the customer share of the gain on the sale of Centralia.

Q What has Staff recommended in this case related to the sale of Centralia?

A Staff has proposed to flow the gain on the sale of Centralia through to customers, but deny recovery of the replacement power costs associated with Centralia. On Page 35, beginning on Line 14 Mr. Buckley recommends that the Commission deny recovery of the replacement power costs "until the Company makes a sufficient showing regarding the long-term cost of replacing Centralia power."

Q Does the Company agree with Staff's recommendation?

A No. The Company has made a sufficient showing for recovery of the Centralia replacement power costs proposed in this case, which I will explain in detail below.

Furthermore, it is important to recognize that the purchase contract with TransAlta that the Company has entered into to replace the Centralia power represents a <u>temporary replacement</u> for a three and one-half year period. This is not the long-term solution. The Company is currently developing a Request for Proposals that it plans to file with the Commission in the very near future. Through this process the Company will evaluate long-term resource alternatives to replace the Centralia output on a long-term basis. The 3 ½ year purchase will provide time to solicit and evaluate bids through the RFP process, as well as provide some time to put the new resources in place. If the new resources involve energy efficiency and/or building a resource, the 3 ½ year period will provide most, if not all, of the time needed to put these resources in place.

Q What are the Commission's standards related to a "sufficient showing?"

A The Commission outlined its prudence standards or guidelines related to resource acquisitions in its Eleventh Supplemental Order in Docket No. UE-920433, dated September 21, 1993, and its Nineteenth Supplemental Order in the same Docket, dated September 27, 1994. The Orders state as follows:

Eleventh Supplemental Order, Docket No. UE-920433, dated September 21, 1993

> The test this Commission applies to measure prudence is what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. (Page 20)
>
> A demonstration of prudence of resource acquisition includes showing both that the selection of the resource was necessary and reasonable and that the costs of acquisition were appropriate. (Page 20)
>
> The Commission's acceptance of a Company's least-cost plan does not represent a finding of prudence of a particular resource. Furthermore, the least-cost planning process is not sufficiently rigorous or specific to support an independent finding of prudence. (Page 21)
>
> Avoided cost is just one more factor which may be considered in determining prudence. However, cost values must be adjusted for items such as load factor and seasonality in order to make a reasonable evaluation of the prudence of the acquisition. (Page 21)
>
> Although the competitive bidding rule (WAC 480-107-060) provides that information gathered in a competitive bid may be used for analysis in a general rate case, the prices submitted pursuant to the bid may be used only for a general, qualified comparison with the acquired resource as another component of the prudence review. (Page 21)
>
> The Commission sees no reason to deviate from the traditional prudence standard recited above, and we concur with Commission Staff that the review should include at a

minimum dispatchability, transmission impacts, other bids, building options, and financial and rate impacts. (Page 22)

Nineteenth Supplemental Order, Docket No. UE-920433, dated September 27, 1994

> The Commission relies upon a reasonableness standard. The company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made. (Page 10)
>
> The prudence standard adopted in prior Commission orders is easily applied to any resource decision, whether it is to build or to purchase. The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost effective manner. When a utility is considering purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself. Specific factors which must be included in its analysis are included in the Public Utility Regulatory Policies Act of 1978 (PURPA), and in Commission rules. Other factors will be identified in the company's least cost plan. The factors identified in the National Energy Policy Act of 1992 will need to be considered in purchases made after its adoption. (Page 11)

Q Please explain how the Company has complied with these standards.

A In prior testimony, during the hearings, I explained the assessment the Company conducted regarding the TransAlta replacement power purchase. This included the recognition of an immediate need for resources of approximately 200 MW, the need for the replacement resource to be contingent upon the sale of Centralia occurring, the opportunity for a replacement resource that excluded the spring run-off period when Centralia is often displaced and the Company is generally in a surplus condition, and finally, a comparison of the TransAlta purchase cost to the price of other power products in the marketplace at the time. (TR pp. 260-265)

The following is a summary of the facts surrounding the TransAlta replacement purchase, and the analysis and decisions made by the Company related to the purchase. I believe this information shows that the Company complied with the Commission's prudence standards and should be allowed full recovery of the TransAlta replacement power costs.

1. The sale of Centralia created an immediate need for resources. Building was not a possible near-term solution because of the immediate need. Acquiring energy efficiency measures was not a near-term solution because of the time frame and the magnitude of replacement energy required. Both of the Company's load/resource tabulations from the 1997 Least Cost Plan and the draft dated November 10, 1999 show an energy deficiency even before the sale of Centralia (Exhibit No. ___ (KON-8). Page 21 of Exhibit T-151 shows an energy deficiency, prior to the sale of Centralia, for every month that the TransAlta purchase was made (July – March).

2. The ultimate sale of Centralia was uncertain, and it was necessary for the replacement resource to be contingent upon the sale of Centralia actually occurring. Furthermore, the replacement resource had to have a flexible start date, contingent upon the closing date for the sale. TransAlta was able to offer this flexibility, because they were in the opposite position as Avista, i.e., they were interested in sales opportunities contingent upon the purchase of Centralia. Otherwise the Company would have had to pay a premium for this flexibility.

3. Waiting until the sale closed before purchasing replacement power would have placed the Company and its customers in a disadvantageous seller's market. The Company would have been short power and everyone would have known it.

4. Given the uncertainty related to the sale of Centralia, conducting an RFP process prior to the close of the sale would not have been a robust process. Potential suppliers generally do not spend the time to submit a competitive bid with this level of uncertainty.

5. The Company is permitted to acquire resources, such as the 3 ½ year TransAlta purchase, without an RFP per WAC 480-107-001 – "These rules do not preclude electric utilities from constructing electric resources, operating conservation programs, purchasing power through negotiated purchase contracts, or otherwise taking action to satisfy their public service obligations."

6. The Company conducted a number of market assessments to determine the heavy-load products, flat products, and seasonal products that were available in the wholesale market to meet the resource need. The brokers that the Company work with provide access to multi-year products offered by major energy suppliers such as Enron, Duke Energy, Williams, El Paso Power, Powerex, PGE and many others. These brokers provide the Company with the lowest price offered by these energy suppliers for the various energy products. The advantage to both sellers and buyers in using brokers is the ability to remain anonymous in the pricing that is both offered and bid. The use of multiple brokers, as well as direct contacts with other utilities and marketers, provides confidence

that the prices are representative of the market. Two of these assessments are documented on Pages 5 and 6 of confidential Exhibit No. C___ (KON-C11).

7. The Company considered economic dispatch, load factor, and seasonality in that the replacement resource actually selected was a nine-month product each year from July through March. The Company did not purchase replacement power for the typical spring runoff months of April, May and June when Centralia is often displaced and shut down for maintenance. The Company was already deficient approximately 100 average megawatts for the July – March period prior to the sale of Centralia (Exhibit T-151, Page 21), therefore the Company needed a high load factor product. The economic analysis comparing cost of the TransAlta purchase with other power alternatives is provided on Pages 1-4 of confidential Exhibit No. C___ (KON-C11). A comparison of the values on the line labeled "Jan - Dec" clearly shows that the TransAlta purchase is less than the alternatives. This confidential Exhibit No. C___ (KON-C11) is the same exhibit sponsored by Mr. Buckley as confidential Exhibit No. C___ (APB-C6).

8. Transmission alternatives were evaluated as shown on Pages 1-4 of confidential Exhibit No. C___ (KON-C11).

9. The TransAlta alternative offered valuable flexibility at a price below the cost of other market alternatives, which resulted in lower rate impacts than the other alternatives (Exhibit No.C ___ (KON-C11)). The rate impacts associated with the replacement power are provided in Exhibit No. C-194.

Mr. Buckley's assertions that the Company "conducted no studies analyzing the actual size or shape of replacement power," and that the Company's analysis was "incomplete" is simply not true. Mr. Buckley's recommendation should be rejected and the Company should be allowed full recovery of the cost of the replacement power related to the sale of Centralia.

It would be unreasonable for customers to enjoy the benefits of the gain on the sale of Centralia, and to require the Company to absorb the costs of the power to replace the resource.

Q Mr. Schoenbeck recommended that the Commission not allow recovery of the replacement costs for Centralia. As the basis for his recommendation, he asserts on Page 27 of his testimony that the Company did not provide "data or analysis to demonstrate the prudence of its decision." Do you agree?

A No. As I have explained above, the Company has complied with the prudence standards outlined by the Commission in acquiring the three and one-half year replacement purchase agreement for Centralia. Mr. Schoenbeck's recommendation should be rejected.

Q On Page 30 of his testimony, Mr. Lazar recommends that the Commission reject the proposed increase in power costs associated with the replacement purchase for Centralia. Do you agree with this recommendation?

A No. Public Counsel is raising the same issue that it presented to the Commission in its Motion to Reopen Centralia Docket (Docket No. UE-991255) dated April 11, 2000.

In the Commission's Fourth Supplemental Order, dated April 21, 2000, rejecting Public Counsel's Motion to Reopen, it stated on Page 8 of its Order that "any comparison of Centralia costs to replacement power costs must include the scrubber investments that are necessary to keep the Centralia plant operating."

A comparison of the replacement power costs for each year shown on Pages 1-4 of confidential Exhibit No. C___ (KON-C11) in the column labeled "Total TransAlta" (on the line labeled "Jan - Dec"), with the ownership and operating costs of Centralia in Mr. Lazar's Exhibit ___ (JL-RR-6) shows that the replacement purchase cost is lower than the costs of Centralia including the scrubbers.

The replacement purchase is higher than the current cost of Centralia excluding the scrubbers, which is why there is an increase in revenue requirement associated with the replacement purchase.

The Company has demonstrated both the need for the replacement resource and the reasonableness of the cost, and Mr. Lazar's recommendation should be rejected.

Q On Page 30 of Mr. Lazar's testimony he recommends that the issue of replacement power costs for Centralia be dealt with in the Company's next general rate case. Do you agree with this recommendation?

A No. The issues surrounding the current and future costs of Centralia as well as replacement power costs were thoroughly addressed in the Centralia sale docket, Docket No. UE-991255. The TransAlta purchase agreement was also introduced and discussed in that case.

In a response, dated March 13, 2000, to Staff Data Request No. 241 C the Company provided the changes in the Company's revenue requirement associated with removing the costs of Centralia and including the TransAlta replacement power costs. This document has been marked as Exhibit C-194.

These two Dockets have provided ample opportunity to review and analyze the numbers. A recommendation by Public Counsel to push this issue into yet a third, future docket is unreasonable and should be rejected. Again, it would be unreasonable for customers to enjoy the benefits of the gain on the sale of Centralia, and to require the Company to absorb the costs of the power to replace the resource.

VIII. COLSTRIP EQUIVALENT AVAILABILITY FACTOR

Q On Page 11 of Mr. Buckley's testimony he proposes an adjustment to increase the equivalent availability factor for Colstrip Units 3 & 4 from the 83.0% proposed by the Company to "about 86%." This would reduce the Company's proforma expenses by $428,400 (system) or $286,985 for the Washington jurisdiction. Do you agree with this adjustment?

A No. The 86% figure proposed by Mr. Buckley is too high for these generating units over time. It is not uncommon for these large generating units to go through a period of years with relatively high equivalent availability factors (EAF), but they do break down from time to time. If the averages that we use for ratemaking purposes exclude those years that the units break down, then we overstate the availability of the plants.

Colstrip Unit 3 was placed into service in 1984 and Unit 4 entered service in 1986. During the 14-year period that both units have been in service, the average EAF has been 82.1%, as shown on Page 1 of Exhibit No. ___ (KON-12).

The North American Electric Reliability Council (NERC) tracks the equivalent availability factors for major generating projects across the country. In computing averages they gather data on similar size generating plants, with a similar vintage, and with similar equipment. This EAF data is published and available in NERC's Generation Availability Data System (GADS) report. The NERC GADS EAFs are reported each month on the Colstrip operating reports for comparison purposes. An excerpt from the January 2000 Colstrip report is attached as Pages 2 and 3 of Exhibit No. ___ (KON-12).

Mr. Buckley proposes to use the period 1994 - 1998 in computing the average EAF. The NERC GADS data shows an EAF of 82.98% for the period 1994-98.

A summary of the EAF figures is as follows:

EAF Proposed by Avista	83.00%
EAF for the Period Units Have Been In Service (1986-99)	82.10%
EAF from NERC GADS Data (1994-98)	82.98%
EAF Proposed by Staff (1994-1998)	86.00%

The 83% EAF proposed by the Company is reasonable when compared with both the average EAF for the period the units have been in service and the NERC GADS data.

IX. MID-COLUMBIA COSTS

Q On Page 10 of Mr. Buckley's testimony he proposes an adjustment to reduce the Mid-Columbia (Wanapum and Priest Rapids) proforma power costs by $222,000 on a system basis, or $148,718 for the Washington jurisdiction. Do you have any comments on this adjustment?

A Yes. When the Company filed its case in October 1999 it made adjustments to power supply revenue and expense items based on the best information available at the time. The Company is not opposed to incorporating updated information into the case as long as the adjustments go both ways.

In Staff's response to Avista's Data Request No. 11 (attached as Exhibit No. ___ (KON-13) it stated as follows:

> "Staff believes updates to "known and measurable" factors such as contract prices or other cost changes that affect power supply expenses are appropriate up to a period that adequate discovery can be accomplished and incorporated into the record."

The Company does not oppose this adjustment.

X. FUEL CELL ADJUSTMENT

Q On Page 28 of Mr. Buckley's testimony he proposes an adjustment to remove $71,000 of proforma power costs on a system basis related to the Fuel Cell Project. Do you agree with this adjustment?

A Yes. The $71,000 shown on Line 79 of Exhibit No. 152 should be removed. The $71,000 expense item is an intra-company entry between the electric and natural gas divisions of the utility. The intra-company revenue entry was eliminated for the proforma period, and this expense entry should also have been eliminated.

As to the Project itself, the Fuel Cell Project is a research and development project related to "clean power" alternatives. The Fuel Cell was installed at the Downtown Doubletree Hotel in Spokane, which is one of Avista's customers. In addition to the electricity produced from the fuel cell, the byproduct heat from the fuel cell is used to preheat water for the hotel.

This project has provided and will continue to provide valuable information. A well-informed utility with regard to these new "clean power" alternatives is beneficial to the Company's customers, the Commission and other stakeholders. Information learned through this project can be passed on to other Avista customers.

The Company provided documentation related to this project in Exhibit No. 163, which included a copy of the customer contract, a report and discussion on the project and various pilot options, and an internal memo regarding the economics of the project.

Revenues from the Doubletree related to this project for the 1998 test period were $94,000, and expenses related to the project were $71,000.

It should be noted that this fuel cell project involves a phosphoric acid fuel cell, which is a completely different technology than that being pursued by the Company's affiliate Avista Labs.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.