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2004 OCT 29 AM 10: 21

IDAHO PUBLIC
UTILITIES COMMISSION

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	) CASE NO. AVU-E-04-1 AVU-G-04-1) AVISTA CORPORATION'S PETITION FOR RECONSIDERATION OF COMMISSION ORDER NO. 29602

Avista Corporation (hereinafter referred to as "Avista" or "the Company"), pursuant to RP 33 and 331, et seq., and Section 61-626, Idaho Code, respectfully petitions the Commission for reconsideration of Order No. 29602, dated October 8, 2004, issued in Case No. AVU-E-04-01 and AVU-G-04-1 (the "Order"). Avista requests reconsideration of Order No. 29602 because certain portions are unreasonable, unlawful, erroneous, and not otherwise in conformity with the facts of record and/or the applicable law, resulting in a revenue requirement and rates which are confiscatory. This Petition is based on the following reasons and upon the following grounds:

I.

THE COMMISSION'S DISALLOWANCE OF ONE-THIRD OF THE COMPANY'S JURISDICTIONAL SHARE OF DEAL A LOSSES, AS PART OF ITS REVIEW OF POWER COST ADJUSTMENT (PCA) ISSUES, FAILS TO RECOGNIZE EVIDENCE OF RECORD AND WAS OTHERWISE UNREASONABLE

A. The Commission's Decision With Reference To "Deals A and B" Natural Gas Hedge Transactions.

Among the PCA issues deferred for resolution in this general rate case, were the costs associated with so-called "Deal A" and "Deal B" natural gas hedge transactions. Deal A consisted of two transactions of 10,000 dth/day each, for a 36-month delivery term, that were entered into for the purpose of hedging, or fixing, the natural gas price for the period November 1, 2001 through October 31, 2004. Lafferty, Direct, Tr. at 564. One transaction was entered into on April 11, 2001 at a price of $6.7525/dth and the second transaction was entered into on May 2, 2001 at a price of $6.50/dth. (Id.)

The second set of transactions, referred to as "Deal B," consisted of two hedge transactions of 10,000 dth/day each, for the 17 month delivery term June 2002 through October 2003. One transaction was entered into on April 10, 2001 and another transaction on May 10, 2001, at prices of $6.50/dth and $5.35/dth, respectively. (Id. at 565.)

As explained by Mr. Robert Lafferty, Manager, Wholesale Marketing and Contracts, Avista was "in a short position on an average basis for the periods of the natural gas transactions." (Id. at 566.)[1] Accordingly, given its short position and high price volatility, the Company had serious concerns regarding the exposure to high energy prices for the Company and its customers. These concerns were magnified by the Company's exposure to the variability

[1] The "short position" refers to the reliance on resources to serve retail customers where the cost of energy is based on short-term wholesale market prices for either electricity or natural gas, i.e., the Company and its customers are exposed to the volatility of short-term wholesale market prices.

of hydroelectric generation as highlighted by the low level of hydroelectric generation in 2001. The combination, therefore, of net system variability and high/volatile energy prices posed a "significant economic risk" to the Company, as testified to by Mr. Lafferty. (Id.)

Accordingly, the Company elected to hedge a portion of the natural gas purchases that had been secured in March of 2001.[2] According to Mr. Lafferty, the amount hedged covered a portion of the monthly deficits associated with the combined variability of loads and hydroelectric generation conditions. (Id.)

In its Order, the Commission disallowed the entirety of Deal B hedge losses, in the amount of $6,496,669, noting that, in its view, these transactions were "highly irregular" and "speculative" and that the Company was "operating outside its own risk management policy." (Order at p. 45). Moreover, inasmuch as the Deal B transactions were with the Company's affiliate, Avista Energy, the Commission noted that no "protocol" had been established for transactions between Avista Energy and Avista's electric operations. (Id. at p. 44)

In addressing Deal A hedge losses, however, the Commission noted that there were certain differences that justified a basis for different treatment:

> Among those differences are the counterparties themselves, neither of whom were affiliates of Avista Utilities, and Staff's analysis that demonstrates that these transactions, had an operating protocol been in place, would have been viewed by Staff to be within the Company's established risk management limits.

(Order at p. 45.) The Commission deemed a "reasonable disallowance" to be one-third of the total losses, or $4,771,550 (Idaho's share).

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2 As explained by Company Witness Lafferty, through the financial hedge transactions of Deals A and B, the Company fixed the price on the physical natural gas purchases for Coyote Springs 2, in order to limit exposure to higher prices and to provide a measure of price stability for customers. (Tr. at p. 610.) It should be remembered that the physical purchases of natural gas made by the Company were at "monthly index prices," and that Deal A and Deal B served to fix the price of the physical purchases. (Id. at p. 611.)

In this Petition, although the Company does not agree with the reasoning behind the Commission's decision to disallow all of Deal B hedge losses and one-third of Deal A hedge losses, the Company, nevertheless, has elected to pursue reconsideration only of the Commission's decision with respect to Deal A hedge losses.[3] This should serve to eliminate all issues concerning affiliate transactions, inasmuch as Deal A, unlike Deal B, did not involve Avista Energy as a counterparty. Accordingly, the need for "operating protocols" governing conduct between a utility and its affiliate, which formed the basis for disallowance of Deal B costs, is not at issue. Deal A hedge losses, therefore, can be viewed strictly on their merits, separate and apart from any Avista Energy involvement. As discussed below, there should be no disallowance of Deal A losses.

B. The Commission's Own Staff Was Correct In Not Opposing The Recovery Of Deal A Hedge Losses.

Staff Witness Keith Hessing, in his direct testimony, was quite clear and unambiguous in his recommendation to disallow only Deal B hedge losses:

> Deal "A" hedges were not done with an Avista affiliate, but Deal "B" hedges were. Also, the Deal "A" gas purchase did not put the Company over the long limit contained in it's Risk Policy, the Deal "B" purchase which was executed at a later point in time caused the utility to exceed the long limit. Not only did the transaction place Avista above the long limit, but Avista's position continued to stay above the limit.

(Hessing, Direct Tr. at 1270.) Therefore, not only did Staff Witness Hessing recognize that Deal A was not done with an affiliate, Deal A also did not put the Company over the long limit contained within its risk policy. In other words, it was well within the Company's risk parameters or "protocols."

[3] There is, however, a simple miscalculation of the disallowance that affects both Deal A and B that needs to be corrected, in any event, as discussed below in Section I.C.3.

Furthermore, Mr. Hessing acknowledged, at Transcript page 1271, that "Avista needed the Coyote Springs 2 plant to reduce its dependence on what had become a highly volatile energy market." According to Mr. Hessing, "Coyote Springs 2 was to be one of the most efficient combined cycle gas-fired combustion turbines in the region with a 7,000 BTU/kWh heat rate." (Id. at 1271-72) Mr. Hessing further noted that the "power needed by customers could be generated at a cost below the market price." (Id.) Simply put, Deal A provided the necessary gas supply, at a fixed cost, to fuel a needed generation plant.

Moreover, Staff Witness Hessing was quite clear in his view that Deal A was not "speculative," notwithstanding his views with respect to Deal B. This was evident in his response to Commissioner Hansen's question:

> Q. Mr. Hessing, I know what you've stated in your testimony; however, I guess I'm just a little confused by your answers to Mr. Ward's questions and I would like you to clarify for me again, if you would, whether you think Deal A was speculative or not, and if it was not, would you explain again why it is not.
>
> A. Well, I think Deal A had some common characteristics with Deal B and it took a price view at the time, but it wasn't speculative, in my mind, I guess beyond what I have already said, because it aligned the Company's loads and resources for the future and within the limits that were set in the Company's risk policy; and it was Deal B that went beyond the limits of the risk policy and the one which is part of the reason that Staff is challenging the costs of Deal B.

(Emphasis added) (Tr. at pp. 1308-09.)

While the absence of "protocols" governing dealings between Avista and its affiliate, Avista Energy, may have had a bearing on the resolution of Deal B hedge transactions, no affiliate was involved in the Deal A transactions. In terms of "protocols" in a broader sense, there were, in fact, "risk policy guidelines" in place. As discussed above, both Company and Staff are in agreement that Deal A did not violate the limits or protocols of the Risk Policy. In fact, as noted earlier, Mr. Hessing concluded with regard to Deal A that ". . . it aligned the Company's loads and resources for the future and within the limits that were set in the company's risk policy." (Id. at 1309.)

In his rebuttal testimony, Company Witness Lafferty provided a chart (attached hereto as Appendix A) demonstrating the Company's load and resource position (at a 90% confidence interval) after including both Deals A and B. It is clearly evident from this analysis that Deal A, if looked at alone, was well within, and consistent with, the Company's resource planning criteria. (See also Exhibit 7, Schedule 26, p. 2.)

Moreover, there was sound analysis conducted by the Company that supported its decision to enter into the Deal A hedge transaction; it was not "cobbled together" after the fact. Mr. Lafferty, in his direct testimony, beginning at Transcript page 578, describes the Company's analysis with reference to its exposure to "net position variability." As he explains, in March of 2001, the Company had performed a Prosym hourly model analysis of monthly net positions for 2002-2004. That model was used to produce data representing the change in the Company's net system requirement position resulting from the combined monthly statistical variability of hydrogeneration and load using both a 90% and 95% confidence interval.[4] The results of that study, as set forth in the attached Appendix A (also appearing at Schedule 26 of Exhibit 7), were described above. This demonstrated that the hedges served to reduce – not entirely eliminate – the Company's net position exposure based on 90% confidence interval planning. Stated differently, with generation available from Deal A natural gas, the Company covered a portion,

[4] "Confidence Interval" (CI) represents the probability of the hydro-load variability staying within a specific MW range. A 90% CI represents a 5% chance that the Company would have to purchase some amount of energy above a specific MW amount for a given month.

but not all, of its exposure to volatile wholesale prices, as testified to by Mr. Lafferty. (Lafferty, Direct, Tr. at 580.)

Not only had the Company, as part of its analysis, conducted extensive modeling of its load/resource balance prior to entering into the hedged transactions, it also undertook a comparative analysis of the cost to generate power at the hedged price of gas compared to electric power prices available at the time. The results of this analysis showed that the hedged natural gas fuel resulted in generation costs in the range of approximately $38/MWh to $48/MWh for CS2, which was substantially lower than the high-price power available in the market. (Tr. at 581.)

Moreover, under its integrated resource planning or protocols on the electric side of its business, Avista's resource portfolio includes generation from hydroelectric, coal, wood-waste, natural gas, and wind resources. In addition, the portfolio has regularly included purchases of power on a long-term, medium-term and short-term basis. These long-term, medium-term and short-term purchases are generally made at fixed prices, as testified to by Mr. Lafferty. (Lafferty, Rebuttal, Tr. at p. 614.) Therefore, fixing the price of index-based physical purchases through the Deal A hedge transactions, was altogether consistent with the Company's resource planning objectives or protocols.

Therefore, when one looks to "prudence" of decision-making at the time the decisions were made, the evidence demonstrates that (a) an analysis of the load/resource balance with Deal A had been conducted, demonstrating that even with Deal A, the Company was in a resource deficit position, and (b) that an examination of forward prices, at the time, demonstrated that the hedged natural gas fuel would result in generation costs of between $38/MWh to $48/MWh – well below the higher-priced power available in the market, and (c) that Deal A hedge transactions were consistent with resource planning objectives and risk policy guidelines or protocols.

In his rebuttal testimony, Company Witness Lafferty, at Transcript page 619, provided a chart which showed a comparison of the cost to generate power with the Deal A natural gas versus the forward price of electricity at the time.[5] This demonstrated that the Deal A transactions "were clearly a lower cost resource for Avista." (Id.) Therefore, both need for the hedge transactions and cost of such transactions were, in fact, analyzed before entering into the transactions.

Staff Witness Hessing, on cross-examination, agreed that he has "seen information provided by the Company" that justified purchasing gas at $6:

> Q. In other words, would you agree that Deals A and B, at the time they were entered into, reflected the cost of the gas that the Company chose to lock in prices for; in other words, a cost defined by those forward market prices.
>
> A. I have seen information provided by the Company that showed that forward electric prices were high enough to justify purchasing gas at $6 if that's the only consideration that is viewed.

(Emphasis added) (Tr. at p. 1305.)

Accordingly, analysis and documentation pertaining to both the load/resource deficits (even with Deal A included) and the forward market prices did exist before the Company entered into the transactions. The following documentation was provided for the record in this case and was available for review by Staff and other interested parties:

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5 Forward market prices for both electricity and natural gas are based on actual forward transactions and actual price bids and price offers by counterparties in the marketplace. These forward market prices are commonly used in the electric and natural gas industry to establish prices for, among other things, medium-term transactions, financial hedge transactions, and to mark-to-market electric and natural gas portfolios for accounting purposes, as explained by Company Witness Lafferty. (Tr. at p. 618.) In this regard, Avista Utilities is a "price-taker" in the market and "pays prices equivalent to the forward prices offered by the marketplace," as testified to by Mr. Lafferty. (Id.)

- The Gas/Electric Transaction Record is contained in Confidential Schedule No. 21 of Exhibit No. 7.

- The Position Report for the relevant days including the cover memo describing market transactions and conditions is contained in Confidential Schedule No. 31 of Exhibit No. 7.

- The information in the Long-Term Physical Electric Load & Resource Tabulation was presented in different forms and data is summarized in Schedule No. 26 and Schedule No. 17 of Exhibit No. 7.

- Forward electric prices compared to the cost to operate the gas-fired generation that the Company expected to operate are summarized on a table in Schedule No. 19 of Exhibit No. 7.

- Natural Gas price curves are contained in Schedule No. 27 of Exhibit No. 7.

- Comparisons of electric market price vs. cost to generate with the most efficient generation unit are contained in the table in Schedule No. 19 of Exhibit No. 7 and are also recorded on the Gas/Electric Transaction Records.

- Third party natural gas forward price data is attached to the Gas/Electric Transaction Records.

In conclusion, with reference to Deal A, Staff appropriately concluded: (1) that no "affiliate" concerns were involved; (2) that it was not "speculative"; (3) that it did not place the Company outside of its risk policy guidelines or protocols (unlike Deal B, according to Staff); (4) that forward electric prices were high enough to justify hedging the purchase costs of gas at $6 levels; and (5) that Deal A provided the necessary gas supply, at a fixed cost, for the needed Coyote Springs 2 generating plant. All of this attests to the "prudence" of Deal A hedge transactions at the time they were entered into.

In its Order at page 46, the Commission determined that there should be a "sharing of risk between ratepayers and shareholders" with reference to these hedging activities. As discussed by Mr. Lafferty, however, there have been many other transactions that the Company has entered into within its risk policy guidelines, which when viewed with hindsight are very favorable for customers:

> . . . A hindsight analysis of Avista's purchase of 200 MW for the period July 2000 through December 2003 shows that it was over $236,000,000 less expensive than purchasing at index prices. In addition, based on current market conditions the 100 aMW of more recent purchases described above for the period 2004 through 2010 will provide customers with over $46,000,000 of benefits.

(Lafferty, Rebuttal Tr. at 617.) The benefits of these transactions have inured primarily to ratepayers, not shareholders.

Accordingly, the Commission's decision to disallow "one-third" of the costs of the Deal A transaction was arbitrary and was not supported by evidence of record.

C. Even If The Commission Were To Continue To Disallow A Portion of Deal A Hedge Losses, It Has Miscalculated The Disallowance.

The preceding discussion demonstrates why the Commission should not disallow any of the Deal A costs. Should it, nevertheless, decide to continue to disallow "one-third" of Deal A costs, there are four miscalculations related to the determination of Deal A losses that need to be corrected. One of the issues, involving the wrong number of days in the month, also affects Deal B. The four issues are:

1. The Commission-ordered disallowance of $4,771,550 is based on "one-third" of the Deal A losses. The Company has already absorbed 10% of the total Deal A losses through the 90%/10% sharing feature of the PCA. The effective disallowance is therefore 40% of the total losses – not the "one-third" disallowance ordered by the Commission.

2. The Deal A disallowance is based on total Deal A losses for the period November 2001 through May 2004. The losses in the period November 2001 through

June 2002, however, had previously been authorized by this Commission for PCA recovery.

3. Staff Exhibit No. 141, relied upon by the Commission, has the wrong number of days for the months of July 2003 through May 2004. This error overstates the loss calculations for both Deal A and Deal B.

4. The Staff Exhibit No. 141 calculation of Deal A gas losses includes an incorrect calculation of the Deal A gas profitably burned for the months of November 2003 through May 2004. It included only one-half of the Deal A gas profitably burned and should have included all of it, since Deal B had ended October 31, 2003.

Incorporating these four adjustments to the calculation of Deal A gas losses results in a Deal A disallowance of **$2,122,937.** This compares to the Deal A disallowance of **$4,771,550** in Order No. 29602. A summary of the adjustments is shown in Table 1 below. A detailed worksheet of these adjustments is shown as Attachment B. Attachment C, consisting of Staff Exhibit No. 141, has been revised to correct for these errors.[6] These calculations are derived from evidence of record.

In addition, as noted above, the number of days in the months is incorrect for the period July 2003 through October 2003 for the Deal B loss calculation. Making this technical correction reduces the Deal B loss by $113,620 from **$6,496,669** to **$6,383,049**. This corrected calculation for Deal B loss is also shown on Attachment C.

1. The Actual Deal A Disallowance is More Than One-Third of The Total Loss.

In its Order at page 46, the Commission found a reasonable disallowance for Deal A to be one-third of the total losses. The ordered disallowance of $4,771,550, however, is based on

[6] While Staff Exhibit No. 141 is marked as "confidential," given the passage of time, the Company is prepared to waive this claim for purposes of facilitating this request for reconsideration.

one-third of the deferred losses for Deal A. The Company has already absorbed 10% of the total Deal A losses through the 90%/10% sharing feature of the PCA. Therefore, the effective disallowance, adding the "one-third" of the deferred losses to the 10% already absorbed, is 40% of the total losses.

In order to make the disallowance equal to one-third of the total losses, the disallowance must be reduced such that the disallowance, plus the 10% already absorbed by the Company, is equal to one-third of the total losses. Making this adjustment alone, without the other adjustments, would serve to reduce the Deal A disallowance to **$3,711,206**. A summary of this adjustment is shown on Table 1 below. A detailed worksheet for this adjustment is shown as Attachment B. This adjustment, moving from a 40% effective disallowance to a 33% disallowance based on total losses, is carried through each of the subsequent adjustments discussed below.

2. The Deal A Loss Period Includes Months Previously Authorized For PCA Recovery.

In its prior Order No. 29377, dated November 18, 2003, regarding the Company's PCA deferrals for the period July 2002 through June 2003, the Commission deferred decisions regarding losses on the sale of Deal A gas ($5,935,949 plus interest of $77,064) pending further consideration in the Company's next electric general rate case. Deal A losses for the period November 2001 through June 2002 were not included in that amount and were not set aside for further consideration. The PCA deferral balance approved for recovery for the twelve (12) month period ending June 2002, in Order No. 29130, dated October 15, 2002, included approval of Deal A costs for the period of November 2001 through June of 2002.

In Order No. 29602 an amount of $4,771,550 for Deal A losses were disallowed which incorrectly includes the amount previously approved for Deal A losses for the period November

2001 through June 2002. The Commission recognizes its previous approval of 90% of Deal A losses for the November 2001 through June 2002 period in Order No. 29602 when it states at page 46 that, "Of that amount $5,636,885 was previously authorized for PCA recovery (July 1 – June 2002)." Were the Commission to order a disallowance based on losses that were previously approved for recovery, it would, in effect, be engaged in retroactive ratemaking. Therefore, an adjustment is necessary in order to reflect only the amount of the Deal A disallowance beginning in July 2002.

For the period July 2002 through May 2004, one-third of the total Deal A loss amount is **$2,249,791**. This adjustment is shown on Table 1, below.

3. Wrong Days In The Month Were Included In Both Deals A and B.

Staff Exhibit No. 141, relied upon by the Commission, has the wrong number of days in the month in the purchase expense calculation and the sales revenue calculation for the months of September 2003 through May 2004. This affects both the Deal A and Deal B loss calculations. For the purchase expense calculation shown in Exhibit 141, every month beginning in July 2003 has 31 days. Instead, some months should be 30 days and February 2004 should be 29 days. For the sales revenue calculation in Exhibit 141, every month beginning July 2003 has 30 days; instead, some months should be 31 days and February 2004 should be 29 days. These adjustments affect July 2003 through May 2004 for Deal A and July 2003 through October 2003 for Deal B. Correcting for this calculation error reduces the Deal A disallowance by $91,035. This adjustment is shown in Table 1, below.

Correcting for this calculation error also reduces the Deal B disallowance by $113,620 from **$6,496,669** to **$6,383,049**. This corrected calculation for Deal B loss is also shown on Attachment C, which is a revised Staff Exhibit No. 141.

4. **<u>The Deal A Loss Calculation Includes An Incorrect Calculation For Gas Profitably Burned For The Period November of 2003 Through May of 2004</u>.**

Only one-half of gas profitably burned was included in Confidential Staff Exhibit No. 141 for the Deal A loss calculation for the period November 2003 through May 2004. The full amount of gas profitably burned should have been included for Deal A during this period.

Staff Witness Hessing recognized in his direct testimony, at Transcript page 1263, that some gas has been burned profitably and, as a result, made adjustments to remove that gas from the Deal A and Deal B loss calculations. Accordingly, Staff Exhibit No. 141, relied upon by the Commission, removes the gas that was profitably burned both from Deal B and from Deal A through October 2003, splitting the amount assigned to each on a fifty-fifty basis. However, there is an error in the calculation that occurs in the November 2003 through May 2004 period where only one-half of the gas profitably burned is removed from Deal A. After Deal B ended on October 31, 2003, all of gas profitably burned should have been assigned to Deal A.

One-third of the total loss amount resulting from the adjustment for this calculation error reduces the Deal A disallowance by $35,819. This adjustment is shown in Table 1.

5. **<u>Summary</u>**

While the Company believes that there should be no disallowance associated with Deal A, correcting for certain miscalculations would serve to reduce the Deal A disallowance to **$2,122,937**. A summary of the adjustments to the Deal A disallowance is shown below in Table 1. A detailed worksheet of these adjustments is shown as Attachment B.

Table 1

Deal A Loss Adjustments

Adjustments to Deal A Losses	Adjustment to Disallowance	Adjusted Disallowance Based on One-Third of Total Losses	Cumulative Reduction from $4,771,550 Commission Disallowance
Adjustment from 40% to one-third	-$1,060,345	$3,711,206	-$1,060,345
Adjustment to Remove Nov 2001 - Jun 2002	-$1,461,415	$2,249,791	-$2,521,759
Adjustment to Correct for Wrong Number of Days	-$91,035	$2,158,756	-$2,612,794
Adjustment to Correct for Amount of Gas Burned	-$35,819	**$2,122,937**	-$2,648,613

II.

THE COMMISSION'S DISALLOWANCE OF COSTS ASSOCIATED WITH BOULDER PARK WAS EXCESSIVE

While the Commission's Order did not take issue with the prudence of Boulder Park as a resource, it did disallow $7.62 million of costs (on a system-basis) relating to the construction of the Company's 25 MW Boulder Park natural gas-fired generating plant. The Commission noted that the original cost estimate in May of 2001 was $21 million, but that the total actual cost, upon completion, was $31.9 million. (Order at p. 17.) The Commission deemed it reasonable to limit the authorized rate base to the original project construction estimate of $21 million plus a 15% contingency, or $24,150,000. This was then compared with the final cost of Boulder Park of approximately $32 million, resulting in a disallowance of $7.62 million on a system basis (Idaho's share is $2.6 million).

A disallowance of $7.62 million out of a $32 million project, represents a disallowance of approximately 25% of total project costs; or, stated differently, approximately two-thirds of the cost overruns, after giving effect to the 15% contingency, were disallowed. This level of disallowance is unduly harsh, when viewed in the context of the record in this case and given its own Staff's recommendations.

Turning now to the evidentiary record developed at hearing, the only witness (other than from the Company) to address the Boulder Park issue was Staff Witness Sterling. Mr. Sterling began by expressing his belief that it was reasonable for Avista to develop the Boulder Park project. (Sterling, Direct, Tr. at 1219.) He noted that market prices at the time were extremely high and no one knew if or when such high prices might subside. He further observed that utilities were pursuing a variety of generating options as well as demand management programs. According to Mr. Sterling, "I thoroughly reviewed the Company's analysis that it completed at the time a decision was made to pursue the project. At that time, I believe a decision to proceed was reasonable." (Tr. at 1219.) And, it is true that the Commission, in its Order, does not take issue with the prudence of the project.

Mr. Sterling, however, goes on to note that, when the project was first proposed, Avista estimated the construction cost to be $21 million. (Id.) That estimate was later revised upward to $23.65 million on June 17, 2001. (Id. at 1220.) The Company's explanation for the cost overruns that subsequently occurred was as follows: "The excess cost for the Boulder Park Project generally stemmed from the fast track design-build approach that the Company chose in order to bring small generation on line as quickly as practical in order to mitigate the high prices and volatility in the electric power market during the energy crisis." (Emphasis added.) (Tr. at 1220.) Avista chose a "fast track-design build approach" in order to bring small generation projects on line as quickly as practical to mitigate the high prices and volatility in the electric power market during the energy crisis. Given that approach, a limited amount of the initial engineering was completed in preparation of the initial estimates of project cost. Therefore, it is reasonable to expect that the original project cost estimates would inevitably escalate when using this approach.

Under different circumstances, more of the engineering and design work would have been completed and incorporated into the initial project cost estimates prior to project start. However, such an approach would have delayed the planned construction schedule. The Company believes its decision to use the "fast track design-build approach" was reasonable given the circumstances of the energy crisis. It is therefore reasonable to expect a broader range in the project's costs than the 15% range adopted by the Commission, given such fast-track design approach called for under the circumstances. Accordingly, while the Company continues to believe that there should have been no disallowance ordered in this case, any disallowance should not, in any event, exceed that recommended by Staff, as discussed below.

Using preliminary, initial construction cost estimates, however, for ultimately judging the reasonableness of the final cost of a project is not necessarily fair or reasonable, as expressly acknowledged by Staff Witness Sterling:

> I might also add that using the initial construction cost estimate as the basis for judging the reasonableness of the final construction cost is not necessarily always fair. The initial estimate could be low or inaccurate.

(Emphasis added) (Sterling, Direct, Tr. at 1224.) Indeed, Staff Witness Sterling went on to acknowledge, at Transcript page 1221, that "some of the explanations [for the cost overruns] are reasonable":

> Avista clearly did not anticipate many of the problems encountered in the project's construction or many of the requirements imposed on the project by

> other agencies. For example, the Company cites incomplete construction plans being provided by the engine generator manufacturer, handicapped building access requirements, road width requirements, paved instead of graveled site grounds, building soundproofing requirements and construction plan approval delays as among the many unexpected factors. I agree that many of these delays and requirements could not have been anticipated.

(Emphasis added) (Id.) With that in mind, Staff Witness Sterling recommended that 10% of the final project costs be disallowed, deeming such a disallowance to be a "fair amount." (Id. at 1224.) Mr. Sterling noted that a 10% disallowance would correspond with three particular cost categories that merited attention: first, construction management costs of $2,159,000 were 2.25 times the revised project estimate; secondly, Avista's project management, engineering and project commissioning costs were $1,110,000; and thirdly, an additional $912,714 was incurred because of the additional time required to complete the project. In total, these three factors resulted in a cost overrun of $3,221,714, or approximately 10% of the total final project costs. (Id. at 1223.)

In the final analysis, the only evidence of record challenging the Company's construction costs for Boulder Park came from Staff Witness Sterling. Mr. Sterling, with a degree in Civil Engineering, offered his expert opinion, based on a detailed analysis of the cost overrun components, and concluded with a recommendation that 10% of the final project costs be disallowed. This was based on a specific examination of particular components of the cost-overrun. The Commission, however, went well beyond his recommendation and disallowed nearly 25% of the final project cost ($7.62 million out of a total cost of $32 million). The evidence of record, therefore, suggests that the Commission's level of disallowance was excessive. Avista believes that a more appropriate level of disallowance, if any disallowance is to be ordered, should reflect the expert analysis of Mr. Sterling, and should result in a total disallowance not exceeding $3.2 million (or $1.1 million for Idaho's share).[7]

III.

TECHNICAL CORRECTION TO PENSION ADJUSTMENT

The electric revenue requirement should be increased by $46,411 and the natural gas revenue requirement should be increased by $11,422 to correctly reflect the impact of the Commission's adjustment to the Company's pension costs. In determining the net operating impact ("NOI") of the pension cost reduction, the necessary step of allocating the "system" corporate level of pension expense to utility operations prior to applying the Idaho jurisdictional allocation factors was omitted. Allocation of the system level of pension expense must first be allocated 92.22% to utility operations. This methodology was utilized by the Company in its direct filing and is reflected in Mr. Falkner's workpapers. The allocation to utility operations was also utilized by Mr. English in preparation of the Staff pension cost adjustment. As noted in Attachment D, column (d), the utility allocation of 92.22% was properly utilized in the determination of the $1,549,386 and $381,311 authorized pension cost levels for electric and natural gas, respectively, as shown on lines 9 and 17. However, that step was omitted in the NOI calculations recreated in column (b), as shown on line 14 and 23. Staff has advised the Company that they concur with this correction.

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7 Finally, to lend further perspective to this issue and, while not an excuse for cost overruns, it is true that Boulder Park, even at $32 million, was cost-effective vis-à-vis other alternatives. As shown in Exhibit 8, Schedule 35, page 1, the original estimated cost of $21 million for Boulder Park resulted in a net present value benefit of $11 million, when compared with other alternatives (which is, coincidentally, the approximate amount of the cost overrun).

IV.

NATURE AND EXTENT OF EVIDENCE AND ARGUMENT TO BE OFFERED ON RECONSIDERATION

In accordance with the Commission's Rule of Procedure 331, Avista is required to state the nature and extent of evidence or argument it will present or offer if reconsideration is granted. Avista believes that the evidentiary record before the Commission and the applicable law requires that the Commission modify Order No. 29602 for the reasons set forth in this Petition for Reconsideration. Avista, accordingly, does not believe that any further evidence is necessary for the Commission to reach that conclusion. Nevertheless, the Company is prepared to present additional testimony in support of each of the items it has identified as requiring modifications as set forth in this Petition.

In conclusion, the Company respectfully requests that the Commission grant reconsideration and modify its Order in accordance with the foregoing.

DATED this 28th day of October, 2004.

AVISTA CORPORATION

By: ____________________
David J. Meyer
Vice President and Chief Counsel for
Regulatory and Governmental Affairs

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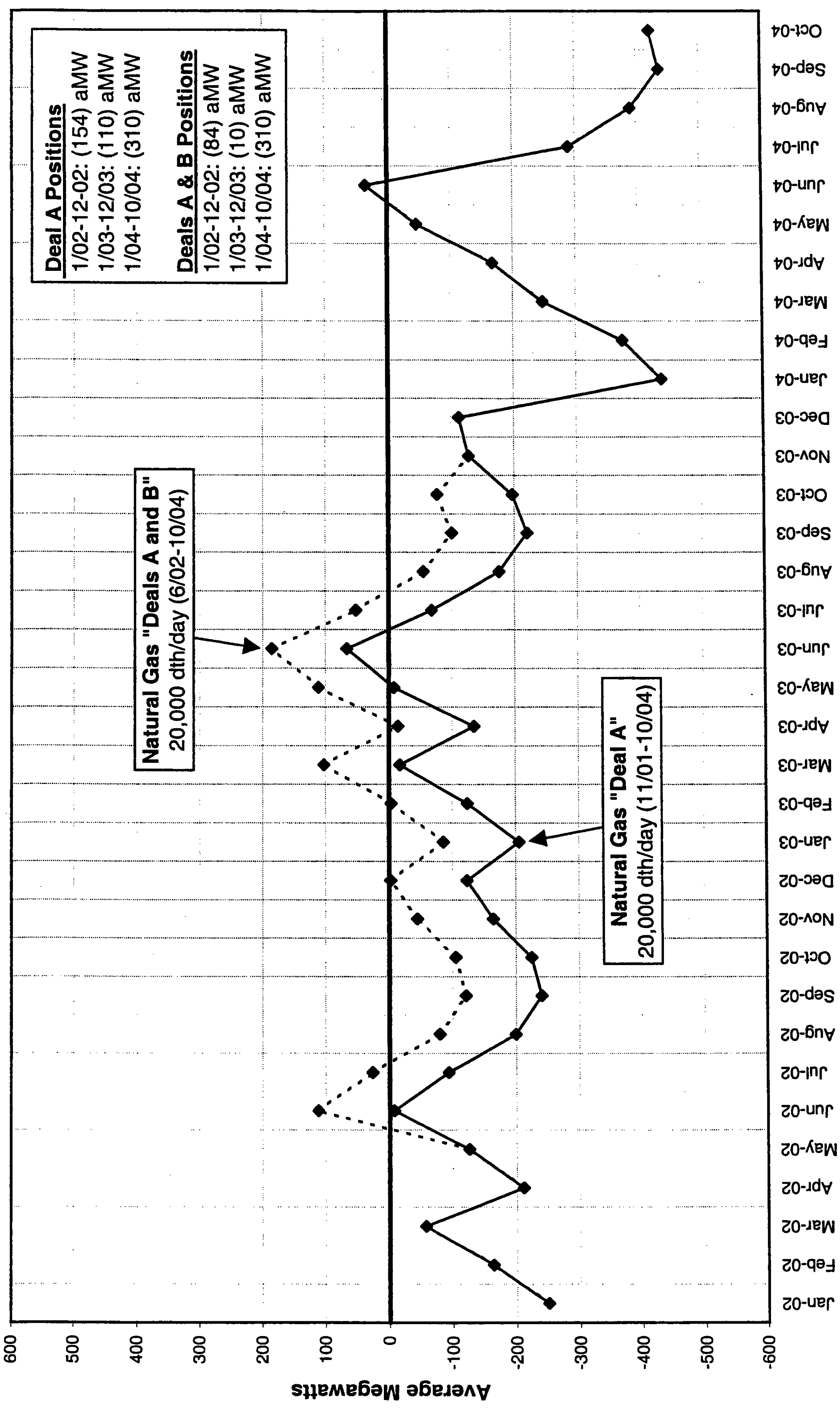
Attachment A

Load & Resource Position Summary - Including Hedged Gas-Fired Generation

90% Confidence Interval (Load & Hydro Variability)

Including Deals A & B Fixed Price Fueled Turbines, as of 3/30/01



Attachment B
Avista Corp.
Detailed Worksheet of Revisions to Calculation of Deal A Losses

Line No.		A	B	C	D	E	F	G	H	I	J
		System Total Loss on Deal A Gas	Idaho Jurisdiction	90% Deferred in PCA	One-Third of Deferred Amount	Change in Disallowance for each Correction	10% Already Absorbed by Company	Total Effective Disallowance	Total Effective Disallowance Percent	Additional Disallowance Beyond 10% to Equal One-Third of Total Loss	Reduction from $4,771,550 Commission Disallowance
			(A * 33.18%)	(B * 90%)	(C / 3)		(B * 10%)	(D + F)	(G / B)	(B / 3 - F)	I - D
1	Losses on Deal A for the period Nov 2001 thru May 2004	$47,936,010	$15,905,168	$14,314,651	**$4,771,550** (1)	$0	$1,590,517	$6,362,067	40%	$3,711,206	-$1,060,345
2	Losses on Deal A for the period July 2002 thru May 2004	$29,059,562 (2)	$9,641,963	$8,677,766	$2,892,589	-$1,878,962	$964,196	$3,856,785	40%	$2,249,791	-$2,521,759
3	Losses on Deal A for the period July 2002 thru May 2004 Corrected for wrong days in the month	$27,883,705	$9,251,813	$8,326,632	$2,775,544	-$117,045	$925,181	$3,700,725	40%	$2,158,756	-$2,612,794
4	Losses on Deal A for the period July 2002 thru May 2004 Corrected for wrong days in the month and gas burned	$27,421,045	$9,098,303	$8,188,472	$2,729,491	-$46,053	$909,830	$3,639,321	40%	**$2,122,937** (3)	-$2,648,613

Notes:

1) This is the disallowance for Deal A ordered by the Commission in Order No. 29602. It is based on one-third of the total Deal A PCA deferred losses for the period November 2001 through May 2004.

2) The amount of $29,059,562 is the system total loss for Deal A for the period July 2002 though May 2004 on line labeled "Losses on Deal A deferred for recovery" in Staff Confidential Exhibit No. 141.

3) This is an amount based on one-third of the total Deal A losses for the period July 2002 though May 2004. Deal A loss calculations have been adjusted to correct the number of days in each month and to include all, rather than only one-half, of the gas profitably burned for the period November 2003 through May 2004.

ATTACHMENT C

Attachment C
Revisions to Staff Exhibit No. 141
Idaho Public Utilities Commission
Staff Case
Avista Utilities Idaho PCA
Calculation of Loss on Gas Sales
Case No. AVU-E-04-01

	DEAL A			DEAL B						
	Delivery November 1, 2001 - October 31, 2004			Delivery June 2002 - October 31, 2003						
	Purchase	Sale	gain/loss	Purchase	Sale	gain/loss				
Month	27,658 decatherms per day, 10,000 locked in at 5.85, 10,000 locked in at 6.7525			20,000 decatherms per day, 10,000 locked in at 6.50, 10,000 locked in at 5.35; then 20000 locked in at 5.9850			Total Monthly Sales	Total Accounts Receivable	Average Weighted Sale Price	Monthly Burn Amount
November-01	$3,780,750	$1,570,542	-$2,210,208				1,969,740	$5,155,933	$2.6176	
December-01	$3,906,775	$1,598,629	-$2,308,146				1,542,317	$3,976,763	$2.5784	
January-02	$3,906,775	$1,370,002	-$2,536,773				851,909	$1,882,447	$2.2097	
February-02	$3,528,700	$1,158,944	-$2,369,756				774,424	$1,602,704	$2.0695	
March-02	$3,906,775	$1,398,131	-$2,508,644				938,398	$2,116,134	$2.2550	
April-02	$3,780,750	$1,483,528	-$2,297,222				839,463	$2,075,612	$2.4725	
May-02	$3,906,775	$1,468,617	-$2,438,158				857,398	$2,030,950	$2.3687	
June-02	$3,780,750	$1,573,209	-$2,207,541	$3,591,000	$1,573,209	-$2,017,791	1,429,740	$3,748,800	$2.6220	
July-02	$3,906,775	$1,732,716	-$2,174,059	$3,710,700	$1,732,716	-$1,977,984	1,497,398	$4,184,782	$2.7947	
August-02	$3,906,775	$1,519,387	-$2,387,388	$3,710,700	$1,519,387	-$2,191,313	1,477,398	$3,620,547	$2.4506	
September-02	$3,780,750	$1,609,065	-$2,171,685	$3,591,000	$1,609,065	-$1,981,935	1,429,740	$3,834,241	$2.6818	
October-02	$3,906,775	$1,984,247	-$1,922,528	$3,710,700	$1,984,247	-$1,726,453	1,474,101	$4,717,711	$3.2004	
November-02	$3,780,750	$2,204,601	-$1,576,149	$3,591,000	$2,204,601	-$1,386,399	1,414,042	$5,195,664	$3.6743	
December-02	$3,906,775	$2,383,369	-$1,523,406	$3,710,700	$2,383,369	-$1,327,331	1,523,840	$5,857,859	$3.8441	
January-03	$3,906,775	$2,484,315	-$1,422,460	$3,710,700	$2,484,315	-$1,226,385	1,504,398	$6,028,063	$4.0070	
February-03	$3,528,700	$2,348,677	-$1,180,023	$3,351,600	$2,348,677	-$1,002,923	1,333,569	$5,593,078	$4.1941	
March-03	$3,906,775	$2,737,346	-$1,169,429	$3,710,700	$2,737,346	-$973,354	1,477,398	$6,522,822	$4.4151	
April-03	$3,780,750	$2,455,735	-$1,325,015	$3,591,000	$2,455,735	-$1,135,265	1,429,583	$5,851,128	$4.0929	
May-03	$3,906,775	$2,300,234	-$1,606,541	$3,710,700	$2,300,234	-$1,410,466	1,477,398	$5,481,227	$3.7101	
June-03	$3,780,750	$2,361,500	-$1,419,250	$3,591,000	$2,361,500	-$1,229,500	1,424,759	$5,607,613	$3.9358	
July-03	$1,115,911	$779,627	-$336,284	$1,054,108	$779,627	-$274,481	1,513,398	$6,699,140	$4.4266	887,750
August-03	$1,512,023	$1,042,816	-$469,208	$1,431,163	$1,042,816	-$388,347	1,551,648	$6,766,682	$4.3610	761,750
September-03	$1,978,680	$1,404,921	-$573,759	$1,875,630	$1,404,921	-$470,709	1,504,073	$6,742,760	$4.4830	573,223
October-03	$2,382,682	$1,605,413	-$777,269	$2,259,933	$1,605,413	-$654,520	1,011,097	$4,298,810	$4.2516	484,801
November-03	$2,600,945	$1,795,048	-$805,897				1,099,598	$4,786,705	$4.3531	187,643
December-03	$2,633,412	$2,110,097	-$523,314				1,279,874	$6,469,000	$5.0544	202,523
January-04	$2,203,799	$1,885,269	-$318,531				1,801,548	$9,727,658	$5.3996	270,851
February-04	$3,621,678	$3,096,118	-$525,560				1,242,339	$6,692,419	$5.3870	5,256
March-04	$3,854,727	$2,884,881	-$969,846				1,314,121	$6,197,395	$4.7160	8,278
April-04	$3,598,130	$2,494,852	-$1,103,278				1,164,740	$5,089,462	$4.3696	29,045
May-04	$3,911,302	$2,771,135	-$1,140,167				1,184,091	$5,286,242	$4.4644	-720
Total Nov 01 thru May 04			-$46,297,493			-$21,375,157				

	System	Idaho Jurisdictional	90 % of Idaho Jurisdictional
Total losses for these particular deals	-$67,672,650	-$22,453,785	-$20,208,407
Losses approved for recovery during the July 2001 - June 2002 PCA period	-$18,876,448	-$6,263,205	-$5,636,885
Losses deferred for recovery during the July 2002 - May 04 Period	-$48,796,202	-$16,190,580	-$14,571,522
Losses on DEAL A deferred for recovery (July 2002 - May 2004)	-$27,421,045	-$9,098,303	-$8,188,473
Losses on DEAL B deferred for recovery	-$21,375,157	-$7,092,277	-$6,383,049

AVISTA UTILITIES

Analysis of Commission Allowed Pension Cost

Case No. AVU-E-04-01 and AVU-G-04-01

ATTACHMENT D

Line No.	Description		Original Calculation	Ordering Page	Corrected Calculation	Ordering Page	Difference
	(a)		(b)	(c)	(d)	(e)	(f)
1	Commission Allowed System Pension Cost		**$ 10,347,343**	pg 24	**$ 10,347,343**	pg 24	**$ -**
2	Company Direct Case System Pension Cost		14,000,000		14,000,000		-
3	System Adjustment to Pension Cost		$ (3,652,657)		$ (3,652,657)		$ -
4	Allocation to Utility (1)	92.22%					
5	Commission Allowed				$ 9,542,320		$ (805,023)
6	Company Direct Case				12,910,800		(1,089,200)
7	Utility Adjustment				$ (3,368,480)		$ 284,177
8	Allocation to Idaho Electric	16.237%					
9	Commission Allowed		$ 1,680,098		**$ 1,549,386**	pg 24	$ (130,712)
10	Company Direct Case		2,273,180		2,096,327		(176,853)
11	Idaho Electric Adjustment		(593,082)		(546,940)		46,142
12	State Income Tax	0.01078	6,393		5,896		(497)
13	Federal Income Tax	0.35	205,341		189,365		(15,976)
14	Net Operating Income Effect		**$ 381,348**	pg 24	$ 351,679		$ (29,669)
15	Increase to Revenue Requirement	0.63926					**$ 46,411**
16	Allocation to Idaho Gas	3.996%					
17	Commission Allowed		$ 413,480		**$ 381,311**	pg 55	$ (32,169)
18	Company Direct Case		559,440		515,916		(43,524)
19	Idaho Gas Adjustment		(145,960)		(134,604)		11,356
20	State Income Tax	0.01078	1,573		1,451		(122)
21	Federal Income Tax	0.35	50,536		46,604		(3,932)
23	Net Operating Income Effect		**$ 93,851**	pg 55	$ 86,549		$ (7,302)
24	Increase to Revenue Requirement	0.63926					**$ 11,422**

(1) Original calculation of the Commission Allowed Pension Cost adjustment did not take into account the step of allocating the system pension cost to the utility operations prior to applying the Idaho Jurisdictional electric and gas allocation factors. This overstatment the expense impact of the pension cost adjustment by $46,142 electric and $11,356 gas which in turn overstated electric NOI by $29,669 and gas NOI by $7,302.