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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-04-01 CASE NO. AVU-G-04-01 REBUTTAL TESTIMONY OF ROBERT J. LAFFERTY

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Robert J. Lafferty. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. Have you previously filed direct testimony in this proceeding?

A. Yes.

Q. What is the scope of your testimony in this proceeding?

A. My rebuttal testimony will respond to the testimony of Dr. Peseau on behalf of Potlatch Corporation, regarding the rate base treatment of Coyote Springs 2 (CS2) and the costs associated with the natural gas contracts that have been referred to as Deal A and Deal B. I will also address Mr. Hessing's testimony regarding Deal A and Deal B. Finally, I will respond to Mr. Sterling's testimony regarding the costs associated with Boulder Park. A table of contents for my testimony is as follows:

Q. Would you please summarize each of the sections of your testimony?

A. Yes. In response to Dr. Peseau's testimony regarding Coyote Springs 2:

- Between July 1, 2003 and January 15, 2004, Coyote Springs 2 performed with a 92% availability factor, generating approximately 85 aMW. It is currently out of service due to a failed transformer, but is expected to return to service in mid to late August.

- Avista Utilities purchased CS2 <u>at cost</u>. It was selected through a rigorous RFP process, which was subjected to third-party review and participated in by Commission Staff. In fact, Staff witness Mr. Sterling concluded in his testimony, "Staff does not oppose inclusion of these costs in rate base for the CS2 plant."

In response to Dr. Peseau's testimony regarding natural gas purchases:

- The Deal A and Deal B natural gas hedge transactions were required to fix the price of physical purchases in order for the resulting generation to be included to cover open positions, as is required by the Energy Resources Risk Policy.

- Through the Deal A and Deal B natural gas hedge transactions, the Company fixed the price on the physical natural gas purchases in order to limit exposure to higher prices and provide a measure of price stability for customers.

- The duration of these purchases was not of an unusual length to cover open power positions. I will provide several examples of similar medium-term transactions, which have been very beneficial.

- The forward price curves at the time Deal A and Deal B occurred provided a good indication of appropriate pricing since they are based on actual bids and transactions in the forward markets.

- Because Avista Energy did not maintain sufficient short positions during the durations of Deal A and Deal B, the gas quantities could not have been carried to term. Dr. Peseau's presumption regarding the amount of profit made by Avista Energy resulting from Deal A and Deal B is not legitimate.

In response to Mr. Hessing's testimony regarding natural gas purchases:

- The Deal A and Deal B hedge transactions did not violate the Company's Energy Resources Risk Policy or the Company's long-term planning criteria, and did not create a speculative long position.
- It would have been inappropriate for the Company to sell the electric generation related to Deal A and Deal B. In fact, had the electricity been sold, the Company would have just re-created the open positions that Deal A and Deal B were intended to cover.
- Mr. Hessing's recommendation of a \$6.5 million disallowance for Deal B is not appropriate. However, if the Commission were to determine that a portion of the Deal B transactions should be disallowed, I will present two alternative methodologies for calculating a disallowance.

In response to Mr. Sterling's testimony regarding Boulder Park:

- I will show that Boulder Park was constructed at a time when the Company was facing extreme market conditions and serious financial difficulties. Given the challenges presented by the market conditions and the project's unique characteristics, the construction costs were not unreasonable. Staff's recommendation of a 10% disallowance is not appropriate.

II. COYOTE SPRINGS 2 – RESPONSE TO DR. PESEAU

Q. On page 13 of his testimony, Dr. Peseau suggests that CS2 is not used and useful. Do you agree with his conclusion?

A. No. The CS2 plant began commercial operation on July 1, 2003. Between July 1, 2003 and January 15, 2004, CS2 performed very well with a 92% availability factor. The plant generated approximately 85 aMW during that period.

The plant is currently out of service due to the failure of the generator step-up transformer. The failed transformer has been repaired and tested. It is currently being shipped back to the CS2 site and is expected to arrive at the end of July 2004. Installation is expected to be completed in the mid to late August time frame, and the plant will again be available for service. Furthermore, Avista has ordered a second transformer as a spare from a different manufacturer to help prevent future interruptions at the plant.

In summary, the transformer issue will be resolved shortly, and the plant has already demonstrated that it will perform at a high availability factor.

Q. Beginning on page 7 of his testimony, Dr. Peseau expresses concern regarding the purchase cost of CS2. What is your response to this testimony?

A. Avista Utilities selected CS2 in December 2000 as part of an all-resource RFP process. The RFP process compared the CS2 project <u>at cost</u> with 32 other supply-side and demand-side proposals from the market at the time. I have described in my pre-filed direct testimony the extensive evaluation, screening steps, and economic analyses that were used to evaluate and compare all of the proposed projects. The Company retained RW Beck to conduct an independent review of the modeling and economic analyses of the supply-side resource proposals. Some excerpts from RW Beck's conclusions after its review of Avista's RFP bid analysis are as follows:

> Avista's approach provided a fair and reasonable methodology to determine which bid option is most viable for Avista. The bid review process was based on sound financial and economic assumptions and the analysis used appropriate information to make decisions regarding future markets and Avista's system needs. (Page 8 of RW Beck Report)

> The approach taken by Avista provided for a fair comparison of the resource options bid as well as the self-build option. The market prices used in the analysis provide a reasonable level of detail and a wide enough range of prices so that bids may be assessed fairly under a variety of market circumstances. (Page 8 of RW Beck Report)

CS2 was acquired <u>at cost</u> from Avista Power. The CS2 project cost was thoroughly evaluated through the 2000 All-Resource RFP process and compared to market proposals for other resource options available at that time. The evaluation process was subjected to third-party review to confirm there was a fair evaluation of all resource options. Commission Staff representatives from Idaho and Washington also monitored the selection process.

Q. What were Commission Staff's conclusions regarding CS2 following their review of the costs in this case?

A. Staff witness Mr. Sterling states on page 24 of his testimony, "I believe the RFP process was fair in all respects, and not intended to favor specific proposals, locations, technologies or bidders." Later on page 26 of his testimony, Mr. Sterling indicates that Staff verified CS2 was transferred "at cost" to Avista Corporation. Mr. Sterling concludes the CS2 section of his testimony by stating on page 29 that "Staff does not oppose inclusion of these costs in rate base for the CS2 plant."

Q. On page 14 of his testimony, Dr. Peseau suggests that Avista Power overpaid for the assets it purchased from PGE and Enron. Do you have any comments on this testimony?

A. Yes. Although Dr. Peseau has testified to his understanding of some of the details of the CS2 purchase by Avista Power from PGE and Enron, the costs at issue in this case are the costs paid by Avista Utilities for CS2, as compared to the costs of other resource alternatives available at the time. As explained above, the costs of the CS2 resource alternative were thoroughly evaluated together with other resource alternatives through an extensive RFP process. The costs were demonstrated to be reasonable and should be approved for recovery in this case.

Q. Beginning on page 12 of his testimony, Dr. Peseau states that Avista Corporation did not follow through on its announcement in December 2000 to transfer the CS2 project to Avista Corporation. Do you have any comments on this testimony?

A. Yes. Immediately following completion of the RFP process in December 2000, Avista announced that CS2 was the preferred resource option. The following excerpts from Avista's news release, dated December 12, 2000, reflect the Company's announcement of the results of the RFP and the selection of CS2 as a utility resource.

> Avista Utilities, today announced the selection of the Coyote Springs 2 site near Boardman, Ore., as the preferred supply-side resource option and three demand-side management bids to meet the utility's growing resource needs. These selections which total about 300 megawatts come from a comparison of company projects and a pool of 32 proposals solicited through a formal Request for Proposal (RFP) issued late August.
>
> Under the terms of the project agreements, ownership of Coyote Springs 2 will be transferred at cost to Avista Utilities from Avista Corp. subsidiary Avista

Power LLC, which acquired Coyote Springs 2 in July from Enron North America and Portland General Electric.

The Company chose to keep ownership of the plant within the Coyote Springs 2, LLC until construction was completed. The reasons for keeping the plant within the Coyote Springs 2, LLC were at least twofold: 1) It is often beneficial to form LLCs to separate costs and liabilities during the construction of a project. This provides liability protection in the event of a catastrophic incident occurring during construction. 2) Avista had planned to obtain separate construction financing for CS2. However, the Company was unable to secure separate financing due to the difficult financial circumstances facing the Company at that time.

It is important to note that the oversight of construction for CS2 was provided by Avista Utilities' personnel from the very beginning of the project. Avista Utilities' Tim Carlberg was selected as Project Manager of CS2 in December 2000, immediately following the selection of CS2 in the RFP process. Construction of the CS2 project began in January 2001. CS2 was transferred to Avista Utilities in January 2003, after construction was substantially complete. The project began commercial operation for the utility in July 2003.

With regard to Dr. Peseau's testimony concerning the sale of one-half of CS2 to Mirant in December 2001, as I explained in my direct testimony, the sale was driven by the very difficult financial circumstances faced by the Company at the time. The Company's increased debt costs and need for liquidity were caused by the unfortunate combination of record low streamflow conditions and the unprecedented high wholesale electric and natural gas market prices, which caused significant increases in power and natural gas costs. The Company's financial circumstances were compounded by the need to finance the construction of CS2 at the same time. Avista sold one-half of the CS2 project to relieve some of the financial strain.

Q. Do you agree with Dr. Peseau's suggestion that the maximum amount of capital that should be allowed into rate base for CS2 is $84,560,000, based on the cost for a Surrogate Avoided Resource (SAR) from the 2002 Avoided Cost proceedings?

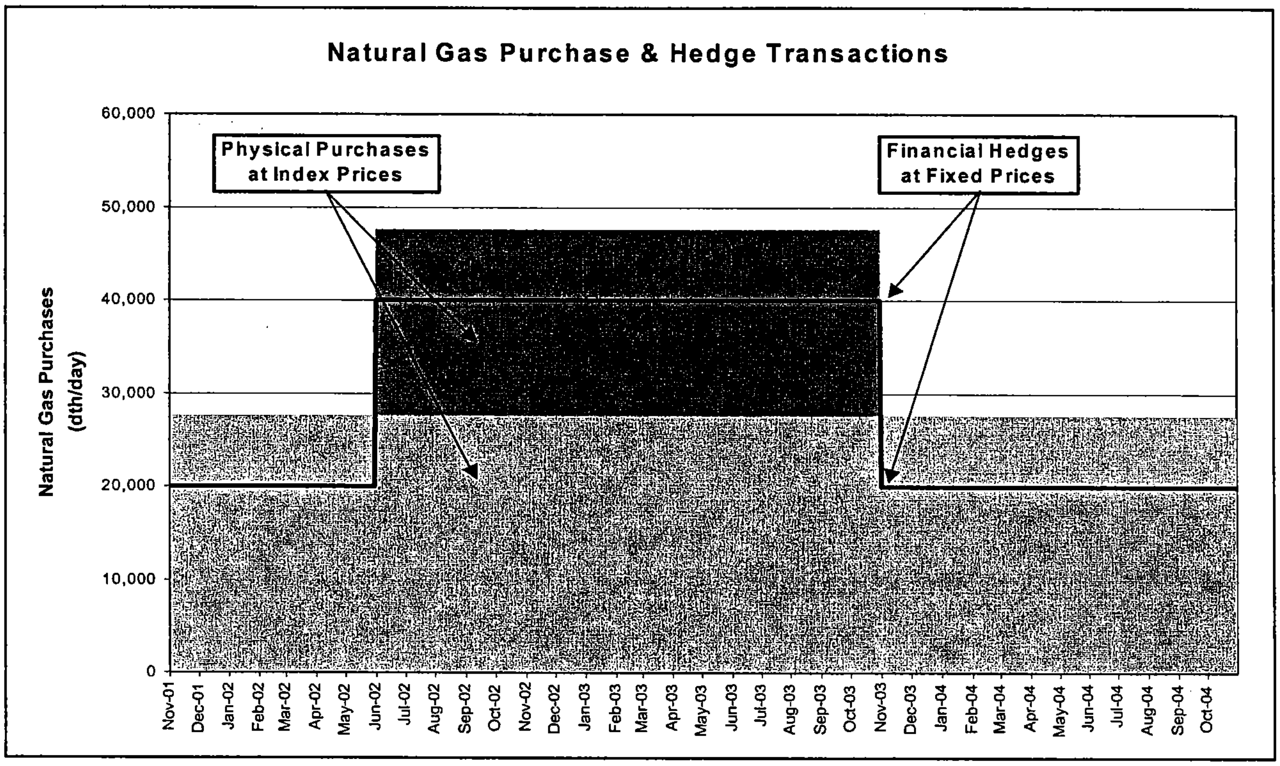
A. No. This suggestion presupposes that Avista's RFP was not a legitimate process for acquiring resources at a fair cost. The RFP was conducted during the second half of the year 2000 and CS2 was selected as the least cost resource in December 2000. In 2000 the market fundamentals reflected that the region was short of resources, which was reflected in the price of all resources evaluated at that time.

The Avoided Cost proceedings referenced by Dr. Peseau occurred in 2002 when the market fundamentals had substantially shifted, the region was in a surplus condition, and market electricity prices were lower. It would not be appropriate now, after the fact, to apply a different cost standard to CS2.

III. NATURAL GAS PURCHASES – RESPONSE TO DR. PESEAU

Q. Before you respond to Dr. Peseau's testimony regarding the Deal A and Deal B natural gas purchases, would you please briefly summarize these transactions?

A. Yes. The following chart illustrates the natural gas transactions that are at issue in this case. These purchases were made by Avista in the first half of 2001 to provide fuel for its natural gas-fired thermal generation.



Physical Natural Gas Purchases

The two shaded areas of the chart reflect purchases of physical natural gas at index prices for two different time periods. On March 13, 2001 Avista purchased 27,658 dth/day for the period November 1, 2001 through October 31, 2004 (36 months). On March 22, 2001 Avista purchased 20,000 dth/day for the period June 1, 2002 through October 31, 2003 (17 months). Prices for both purchases were based on the monthly index price published by Natural Gas Intelligence at Malin (NGI Monthly Malin Index).

Although these purchases provided Avista with firm delivery of natural gas to run its gas-fired thermal resources for these time periods, it is important to recognize that these purchases did not limit in any way the cost of power from the generating projects. The Company and its customers were still exposed to the volatility of natural gas market prices during the term of the purchases. Through the financial hedge transactions explained below, the Company fixed the price on the physical natural gas purchases in order to limit exposure to higher prices and provide a measure of price stability for customers.

Fixed Price Financial Hedge Transactions (Deals A and B)

The solid lines on the chart above reflect the volume of natural gas for which the Company fixed the price. Avista fixed the price through four different financial swaps as shown in the table below.

Natural Gas Hedge Transactions				
Deal	**Transaction Date**	**Volume (dth/day)**	**Term**	**Price ($/dth)**
Deal A	04/11/2001	10,000	11/01/2001-10/31/2004	$6.7525
	05/02/2001	10,000	11/01/2001-10/31/2004	$5.9500
Deal B	04/10/2001	10,000	06/01/2002-10/31/2003	$6.5000
	05/10/2001	10,000	06/01/2002-10/31/2003	$5.3500

The combination of the physical gas purchases and financial hedge transactions resulted in a firm supply of power (from gas-fired generation) at a fixed price. Based on the CS2 heat rate, the cost of power from these Deal A and Deal B transactions was in the range of $38 to $48 per MWh. As will be discussed later, these prices compared very favorably to forward electric prices at the time.

Q. Beginning on page 16 of his testimony, Dr. Peseau provides testimony regarding the "distinction" between physical transactions and financial transactions. Do you have any comments on this testimony?

A. Yes. On page 21, line 3 of his testimony Dr. Peseau states the following:

> However, I am quite surprised that the Company testimony in this regard suggests that somehow Deal A and Deal B in any way assisted in <u>covering a resource-short position</u>. (underscore added)

In addition, on page 21, beginning on line 19 he provides the following testimony:

> The company on March 13 and March 22, 2001, entered into 36 month and 17 month physical trades for 27,658 and 20,000 decatherms per day at market index-based prices. <u>These two gas contracts alone filled the need to cover the resource deficits discussed by the Company.</u> (underscore added)

The "two gas contracts" that Dr. Peseau refers to above are the <u>physical purchases</u> of natural gas made by the Company at monthly index prices, whereas the "Deal A and Deal B" transactions that he refers to are the financial hedge transactions that <u>fixed the price of the physical purchases</u>. In his testimony, Dr. Peseau is suggesting that the physical purchases were sufficient to cover Avista's resource deficiencies, and the financial hedges were not necessary. We strongly disagree.

Q. Please explain.

A. The Company's Energy Resources Risk Policy, dated November 9, 2000, under subsection b of Section E, states as follows:

> Resources or loads priced based on <u>index values</u> are considered to be <u>open positions</u> for the purpose of measuring financial risk. Generating plants may be included as resources to cover open power positions only to the extent that fuel has been purchased (<u>other than at index prices</u>) and the plant is available for operation. (underscores added)

In accordance with the Risk Policy, only fixed-price power purchases or power generated with fixed-price fuel is netted against load obligations in the Company's Position Reports. While it is true that the physical purchases of natural gas provided the ability to generate a firm supply of power from thermal generation, Deal A and Deal B fixed the price for the generation, therefore reducing the open financial positions. Without the financial hedges the Company and its customers were still exposed to volatile natural gas market prices, because the pricing for the physical supply was based on market index prices.

Fixing the price on the natural gas through Deal A and Deal B was consistent with Avista's prior purchasing practices of acquiring medium-term and long-term firm resources at fixed prices to serve its electric retail customers. I will discuss this in more detail later.

Q. Beginning on page 24, line 16 of his testimony, Dr. Peseau discusses a resource portfolio that includes short, medium, and long-term resources. Do you have any comments on this testimony?

A. Yes. Beginning on page 24, line 17, Dr. Peseau testifies as follows:

> I certainly agree with him [Mr. Lafferty] that any resource portfolio should have various short, medium, and long-term resources. In this light, I do not challenge or take issue with Avista's entering into its March 13 and March 22 long-term physical gas purchase contracts, as I previously noted.

Dr. Peseau has underscored the word "physical," apparently to emphasis his belief that by purchasing the physical natural gas for thermal generation, it covered the open positions carried by the Company. As I explained above, however, the purchase of the physical natural gas, standing alone, did nothing to protect customers from the impacts of short-term wholesale market prices. Because the physical gas was priced based on the NGI Monthly Malin Index, the price would float each month based on the short-term wholesale market price. As stated earlier, Deal A and Deal B fixed the price for the thermal generation, therefore reducing the open financial positions.

One of the primary purposes in developing a resource portfolio is to provide for diversity of pricing to provide a level of price stability for customers. It is important to note that a resource portfolio could easily be developed to include short-term contracts, medium-term contracts and long-term contracts, but with all of the pricing based on the same short-term index price. From a cost perspective, which is what ultimately counts for customers, such a portfolio would not be much of a portfolio at all, since the pricing for all of the components would be based on the same short-term market price. California experienced this in 2000 and 2001. Through its restructuring initiatives it required utilities to sell their generating resources and purchase power at short-term market prices. In fact the utilities were precluded from entering into longer-term fixed-price transactions.

Q. On page 28 of his testimony, Dr. Peseau made reference to "Avista's normal hedge strategies." Do you have any comments on this testimony?

A. Yes. Dr. Peseau's testimony refers to the Company's hedging practices for its retail natural gas business. It is very important that the purchasing practices and hedging strategies for the natural gas distribution business not be confused with the purchasing practices and strategies of the vertically integrated electric utility.

In acquiring natural gas to serve its retail natural gas customers, the Company purchases natural gas in advance at first-of-the-month (FOM) index prices to cover its expected load requirements. As an additional step, the Company enters into financial hedge transactions to fix the price on a portion of the natural gas in order to limit exposure to higher prices and provide a level of price stability for customers. Some of the financial hedges stretch out for over a year in advance, while other hedges are made for the upcoming winter heating season. Deals A and B were designed to accomplish the same thing, i.e., close the open financial positions, limit customers' exposure to higher prices, and provide a level of price stability.

Avista does not own natural gas production fields or primary pipelines related to it retail natural gas business. Avista purchases all of its supply from the marketplace. Over time Avista has developed its natural gas purchasing practices and hedging strategies in consultation with the Commission Staffs in Idaho, Washington, and Oregon, both through informal communications, through the natural gas IRP process and through the current Benchmark Mechanism. In prior years, a much lower percentage of the natural gas volumes was hedged. However, in more recent years there has been movement toward hedging a greater percentage of the volumes due to the increased volatility and level of natural gas prices.

With regard to the vertically integrated electric utility, Avista operates and continues to develop a diversified portfolio of electric resources to serve its retail electric customers. As Mr. Storro explained in his pre-filed direct testimony, 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 <u>fixed prices</u>.

It is worth noting that prior to the acquisition of CS2, the Company's gas-fired generating plants were all peaking units. The heat rates of the Rathdrum and Northeast units are high as compared to a resource like CS2 that has a heat rate of approximately 7,000 BTU/KWh. The ownership of CS2, a base-load gas-fired project, brings with it a greater need to enter into hedge transactions to cover the open financial positions.

Q. On page 17, line 15 of his testimony, Dr. Peseau suggests that the Deal A and Deal B transactions are of "unprecedented length." Do you agree?

A No. The natural gas transactions at issue were designed to provide a firm supply of power to Avista's electric retail customers at fixed prices. As I explained earlier, historically Avista has regularly entered into medium-term fixed-price transactions, of two to five years, in developing its portfolio of resources to serve its electric customers. For example, in 1997 Avista entered into a purchase of 50 aMW from ESI for the period July 1, 1997 through June 30, 2001 at a fixed price of $14.65 per MWh. In 1997 Avista entered into a purchase of 25 MW on-peak for the period January 1, 1999 through December 31, 2001 at a fixed price of $17.25 per MWh.

More recently, the Company entered into transactions for 100 aMW of firm power at fixed prices for the period January 1, 2004 through December 31, 2006 at an average price of $29.88 per MWh. And an additional 100 aMW of firm power at fixed prices for the period January 1, 2007 through December 31, 2010 at an average price of $31.68 per MWh.

There are at least a couple of points worth noting related to these contracts. First, these transactions were entered into for multiple years to provide a firm supply of power to our electric customers at a fixed price, which is precisely what was accomplished through the natural gas transactions at issue in this case. Secondly, when these types of transactions are viewed after-the-fact, the pricing for some of them will "turn out to be" favorable, while others will be unfavorable. That is the reality of hedging or locking in the price of resources for future periods. The alternative to locking in future prices is to carry large open positions, which would expose the Company and its customers to the impacts of potentially volatile wholesale market prices.

The medium-term transactions noted above, when viewed with hindsight, were very favorable. Current market prices are well above the fixed prices for the 2004-2006 transactions, and Avista's customers are currently receiving the benefit from these fixed-price medium-term transactions. The hindsight approach to proposing a disallowance of unfavorable transactions while accepting the favorable transactions is not reasonable, balanced, or appropriate.

Q. On page 17, line 15 of his testimony, Dr. Peseau makes reference to a loss on a system basis of over $62 million related to the Deal A and B transactions. Should the Commission be persuaded by this figure?

A. No. First, as described above, it is not appropriate to use an after-the-fact analysis of transactions in the determination of the prudence or recoverability of the costs. The Commission has consistently held that the prudence of costs should be determined based on the information available at the time the decision was made.

Second, if an after-the-fact analysis of transactions were to be considered in any way in the determination of the prudence or recoverability of costs in this case, it is imperative that the analysis not be limited to just the few transactions selected by Dr. Peseau. There are many other transactions that the Company has entered into, which when viewed with hindsight, are very favorable for customers. For example, a hindsight analysis of Avista's purchase of 200 MW for the period July 2000 through December 2003 shows that it was over $236 million 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 million of benefits. Therefore, the $62 million highlighted by Dr. Peseau is small when compared to the benefits to customers of other recent and ongoing medium-term fixed-price transactions.

The Company is not proposing that the Commission use an after-the-fact analysis in its decision-making regarding the prudence or recoverability of costs, but has presented the information in response to the after-the-fact approach used by Dr. Peseau in order to provide a more balanced view of the overall transactions entered into by the Company.

Q. Beginning on page 17 of his testimony, Dr. Peseau speculates as to the roles and responsibilities of Avista Utilities and Avista Energy in the Deal B hedge transactions, as well as the reasons why Avista Utilities entered into the hedges. Do you have any comments on this testimony?

A. Yes. As I explained in my pre-filed direct testimony and earlier in this testimony, the reason Avista Utilities entered into the transactions was to cover open financial positions, limit exposure to higher prices, and achieve some price stability for that portion of its electric resource portfolio. Avista Utilities was not "betting" or speculating on the future movement of market prices for natural gas or electric power.

The Deal B hedge transactions were purchased to start in June 2002, when CS2 was expected to become commercial. As such, the Deal B hedge transactions needed to cover a non-standard term (17 months starting in June). Avista Utilities requested that Avista Energy enter into the hedge transactions due to the non-standard term. Also, there were limited counterparties willing to transact with Avista Utilities. The documentation provided in this case shows that the fixed prices for the hedge transactions properly reflected the market price of natural gas at the time the transactions occurred.

Q. On page 26 of his testimony, Dr. Peseau suggests that the forward price curves at the time Deal A and Deal B occurred may not be a good indication of what an arms-length buyer and seller might agree upon for financial hedges. Do you agree with Dr. Peseau?

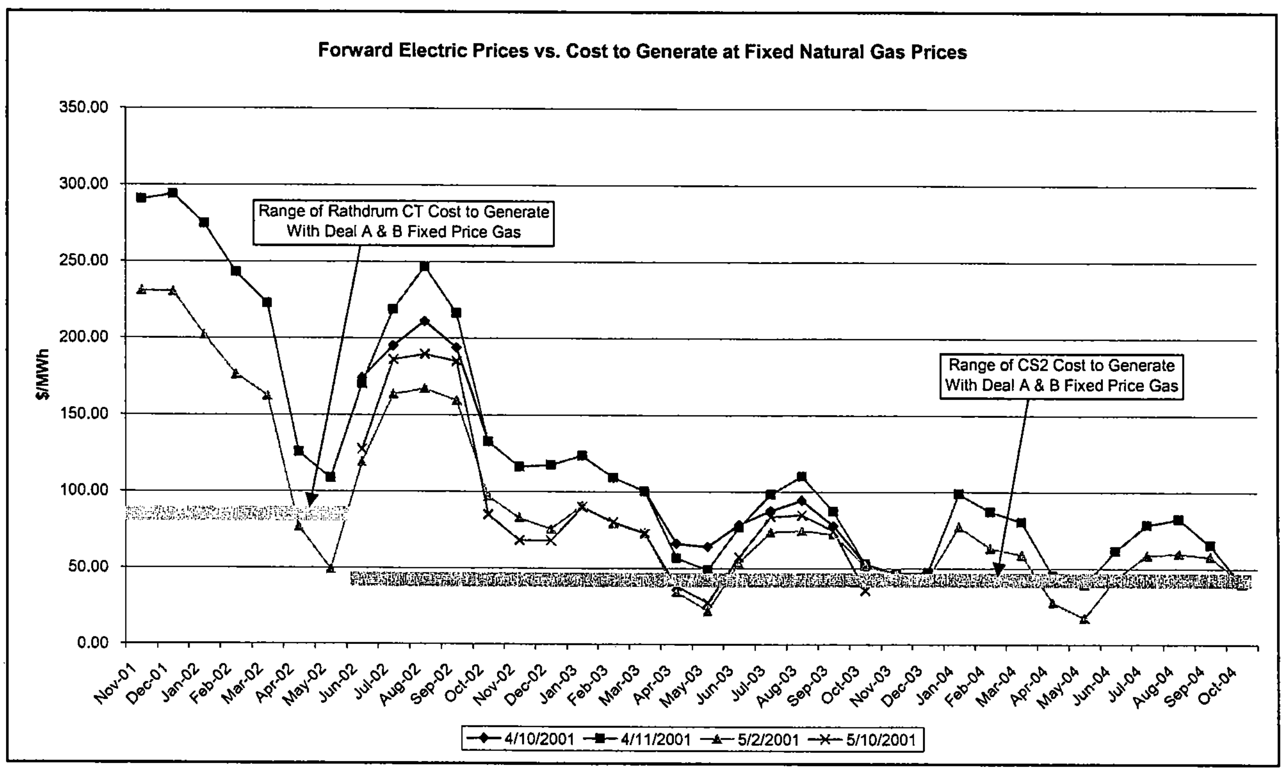
A. No. Forward market prices for both electricity and natural gas are based on actual forward transactions and actual price bids and price offers by counterparties in the marketplace. These forward market prices are commonly used in the electric and natural gas industry to establish prices for, among other things, medium-term transactions, financial hedge transactions, and to mark-to-market electric and natural gas portfolios for accounting purposes.

Avista Utilities is a price-taker in the market and pays prices equivalent to the forward prices offered by the marketplace. Therefore, the forward market price information provided in my pre-filed direct testimony is a reasonable and valid comparison for judging the prudence of the hedge transactions at that time.

Q. On page 22 of his testimony, Dr. Peseau seems to imply that a comparison of the cost to generate power at CS2 with the cost to purchase electric power from the market is somehow improper. Do you have any comments on this testimony?

A. Yes. The comparison between the cost to generate with fixed-price fuel and the cost to purchase electric power in the market is an appropriate comparison continually made by load serving utilities in the determination of least-cost resources to serve load, and in the economic dispatch of natural gas-fired generating plants. The comparison made by Avista was appropriate and proper.

The chart below provides a comparison of the cost to generate power with the Deal A and Deal B natural gas versus the forward price of electricity at the time. As shown in the chart, the Deal A and Deal B transactions were clearly a lower cost resource for Avista.



Q. On page 22 of his testimony, Dr. Peseau makes reference to an "arbitrage" trade. Do you have any comments on this testimony?

A. Yes. An assessment of what a <u>power trader</u> might do with an open position to lock in a profit is not appropriate. A power trader does not face the same circumstances as a utility such as Avista that has an obligation to serve variable loads. If Avista had sold power when it hedged the price of natural gas, it would have <u>re-created</u> a short financial and physical net position, and the Company would have been exposed again to potentially high and volatile prices in the energy market.

Q. On page 18, line 11 of his testimony, Dr. Peseau makes comments regarding information on future market prices that may or may not have been available at the time Deal B was entered into, and then on page 27, line 15 he suggests that Avista Energy received substantial benefits from the Deal B transactions. Do you have any comments on this testimony?

A. Yes. In his testimony, Dr. Peseau is speculating not only on what Avista Energy may or may not have known about future market prices, but also about the status of Avista Energy's contract portfolio and open positions. Because Avista Energy is not a load-serving utility, the forward positions that it takes in the market are generally made not only to capitalize on the movement of prices over time in the same location, but also the movement in the relationship of prices between locations (location spread), and the change in prices over time between commodities (e.g., electricity versus natural gas), among others. At any point in time Avista Energy will be in a net short or net long position in the market. The net short or long position is the result of an accumulation of transactions that have been entered into over time. For any forward month Avista Energy may enter into additional transactions to reverse a position for a variety of reasons.

A "location spread" is a good example of a transaction where a trading company, such as Avista Energy, may not care whether the future market prices move up or down. If positions have been taken related to the difference in prices between locations (location spread), the controlling factor is the difference in the prices between the two locations, not whether the overall prices move up or down. Therefore, one would need to be careful when making assumptions about why certain positions were taken by a trading company, and drawing conclusions regarding the profitability of isolated transactions.

On page 27, line 15 of Dr. Peseau's testimony he suggests that Avista Energy profited from Deal B by over $18 million. In reaching this conclusion, however, one would have to assume that Avista Energy held onto the monthly index-price open positions created by the Deal B transactions during the entire 17-month term. In other words, Avista Energy would have needed to hold "short" positions (at index prices) equal to Deal B volumes during the entire 17 months in order to capture the difference between the Deal B fixed prices and the monthly index prices. In the absence of short positions at Malin, Avista Energy would not have been able to take advantage of declining prices during the 17-month term of the Deal B transactions. In reviewing the open positions of Avista Energy, we know with certainty that Avista Energy did not carry "short" open positions at Malin for the majority of the months of the Deal B term. Therefore, it clearly cannot be assumed that Avista Energy profited by $18 million from the Deal B transactions.

IV. NATURAL GAS PURCHASES – RESPONSE TO MR. HESSING

Q. Beginning on page 17, line 14, of his testimony, Mr. Hessing suggests that the Company created a speculative long position through the Deal B hedge transactions. Do you agree?

A. No. Avista evaluates its load and resource positions and need for resources on both a long-term and short-term basis. For long-term planning the Company uses the Integrated Resource Planning (IRP) process, which has guidelines or criteria related to the resource positions (surpluses/deficiencies) to be targeted by the Company. For short-term planning and operating purposes the Company operates under a Risk Policy, which includes guidelines for resource positions for the near-term 18-month period. A review of both the long-term criteria and the short-term criteria shows that the Deal B transactions did not place the Company outside of its guidelines, and did not create a speculative position.

Q. Please show how Deal B fits within the long-term planning criteria.

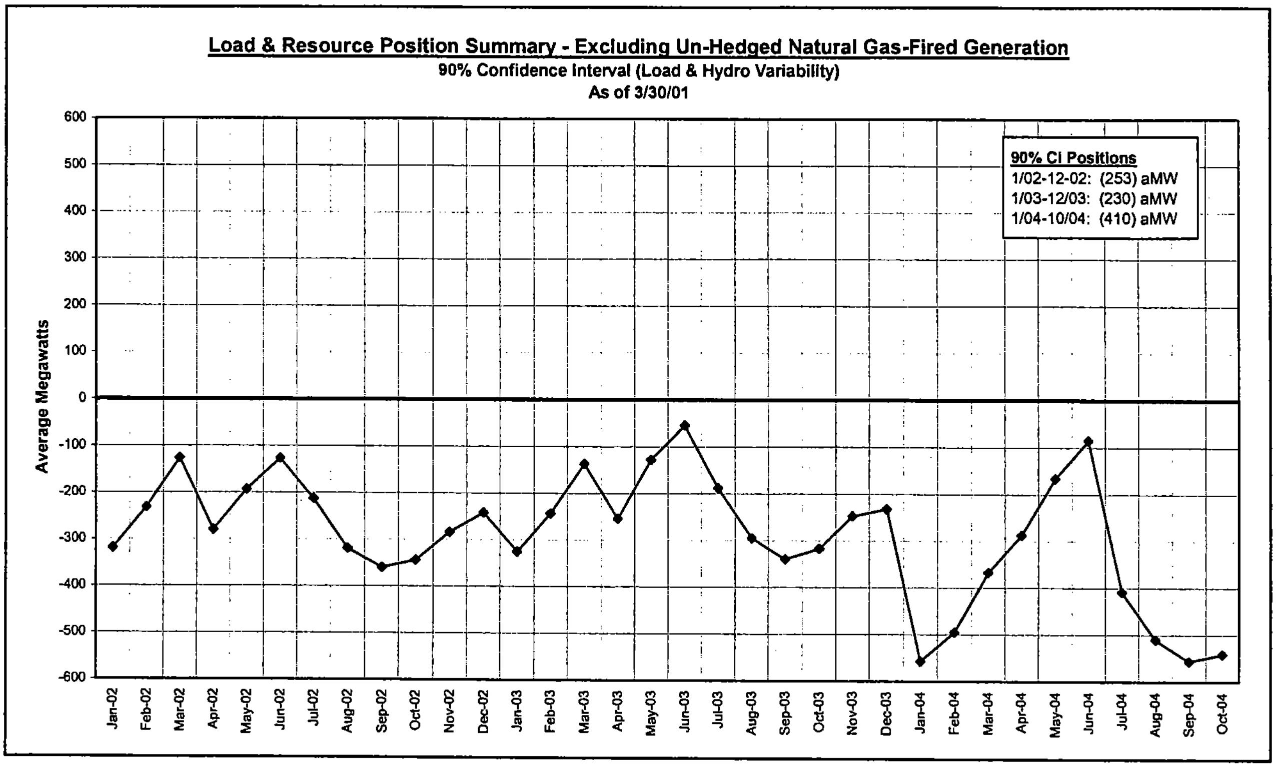
A. Historically, Avista has planned for resource acquisitions to meet its long-term load obligations on a critical water planning basis. Critical water was the basis for prior year Integrated Resource Plans and resource acquisition processes (e.g., RFP) developed by the Company. The difference in hydroelectric generation between <u>critical</u> and <u>average</u> water conditions is approximately 150 aMW. Therefore, as a guideline for long-term planning purposes, in order to cover all load obligations under critical water conditions, it would require an additional 150 aMW of resources. This would translate into a surplus under <u>average</u> water conditions of approximately 150 aMW. For comparison purposes, in 2001

Avista experienced record low streamflow conditions resulting in hydroelectric generation of 181 aMW below average.

Also, at the time the Company entered into Deal B it had also developed additional criteria to use as a guide in its resource acquisition decisions. The Company conducted a statistical analysis of the variability of loads and hydroelectric generation, at a 90% confidence interval, to determine the resources that would be required to cover this variability. I discussed this in more detail in my pre-filed direct testimony, and I will refer to it here as "Confidence Interval" planning. The results of the statistical analysis showed that it would require 170 aMW of additional resources to cover the load and hydroelectric resource variability. This is slightly higher than the 150 aMW under critical water planning, but not too dissimilar.

The following chart[1] illustrates Avista's monthly forward positions as of March 30, 2001 under the long-term confidence interval planning criteria. The chart reflects Avista's resource positions just prior to entering into the Deal A and B transactions. As can be seen in the chart, the Company had resource deficiencies during all months of the Deal A and Deal B periods.

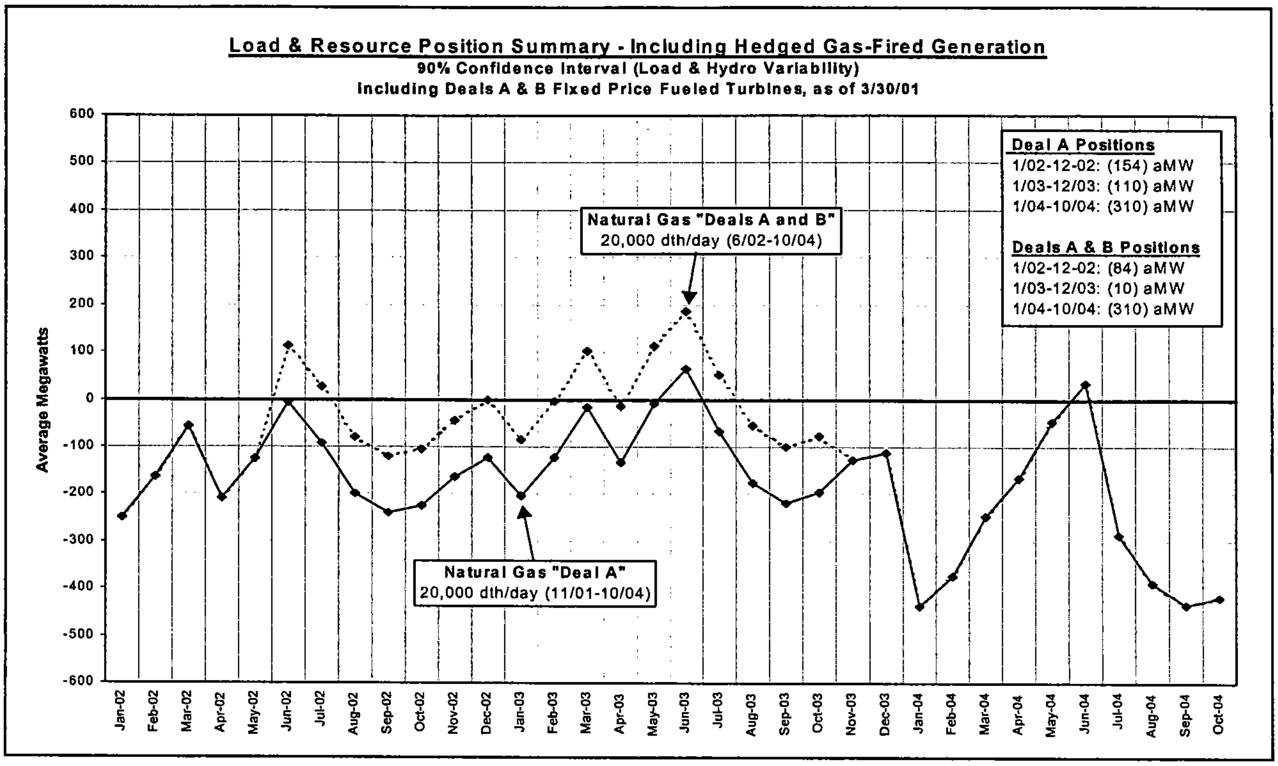
[1] This chart was included in Exhibit No. 7, Schedule No. 26 of Mr. Lafferty's pre-filed direct testimony.



Q. How does the chart change when you add the Deal A and Deal B transactions?

A. Adding the generation related to the Deal A and Deal B transactions results in the positions shown in the chart below.[2] Although there are some surpluses during the spring run-off months of the Deal B period, <u>the average position</u> during the Deal B period from June 2002 – October 2003 is <u>a deficiency of six average megawatts</u>. Therefore Deals A and B both fall within the long-term planning criteria, and did not create a speculative long position as suggested by Mr. Hessing.

[2] This chart was included in Exhibit No. 7, Schedule No. 26 of Mr. Lafferty's pre-filed direct testimony.



Q. For Avista's near-term planning under the Risk Policy for an 18-month period, were the Company's resource positions within the established guidelines when the Company entered into Deal B?

A. Yes. The Deal B transactions were completed in May 2001. The 18-month planning period under the Risk Policy at that time would have run from June 2001 through November 2002. The Risk Policy limits quarterly surpluses to 150 aMW, as Mr. Hessing noted on page 9, line 23 of his testimony. The Company's resource positions for each quarter of 2002, including both Deals A and B, are provided in the table below.

Quarter	Surplus/(Deficit)
Q1	16
Q2	142
Q3	109
Q4	97

During each of the quarters the Company is within its policy guideline; i.e., within 150 aMW. Therefore, the Company's resource positions including Deals A and B were within the established guidelines in the Risk Policy, and did not establish a "speculative" position that was beyond the guidelines.

Q. On page 16, lines 3-4 of his testimony, Mr. Hessing states that "it is Staff's position that the Company violated both the intent and the written requirements of its own Energy Resources Risk Policy" with regard to Deal B. Do you agree?

A. No. The Company operated <u>within</u> the requirements of its Energy Resources Risk Policy and does not agree with Staff's conclusion. As stated in Witness Storro's pre-filed direct testimony, the purpose of the Energy Resources Risk Policy is to provide guidance with regard to the management of the Company's risk exposure as it relates to energy resources.

In Section B of the Risk Policy there are statements illustrating the intended operation of the Risk Policy. The following is an excerpt from Section B of the Risk Policy:

> This Policy is intended to focus on short-term power and natural gas supply management, meaning the period of eighteen months forward from any current date, as they relate to meeting near-term energy load obligations. The longer-term energy risks are expected to be addressed through other means, including the Integrated Resource Planning (IRP) process, capital budgeting and financial planning, load forecasting and econometric models, and generating facility planning. There is not a clear line between the short-term focus of this Policy and long-term energy management. Therefore, decisions and analyses must stretch across arbitrary time boundaries to afford prudent decisions. The short-term horizon in this Policy provides for visibility in the most volatile forward periods, including daily position reporting and transaction authority, but is not intended to be a sufficient tool to manage all energy risk for long-term business requirements.

The Risk Policy makes it clear that it is an operating tool to guide and manage the Company's acquisition and sale of energy resources in the short term. However, it specifically recognizes that there are other tools that guide longer-term resource decisions. The Risk Policy acknowledges that longer-term decisions will cross the 18-month time boundary. In the case of the Deal A and Deal B natural gas hedges, the Company took reasonable medium-term resource acquisition steps and managed its load and resource positions, exercising management's financial risk judgment, consistent with the intent and design of the Risk Policy and with the Company's long-term planning criteria.

Q. Beginning on page 17, line 14, of his testimony, Mr. Hessing suggests that the Company should have sold the electric generation related to Deals A and B, and he states that "Absent such an electric power sale, the transaction was purely speculation." Do you agree with this testimony?

A. No. As I explained above, the Company's resource positions including Deals A and B, under both the long-term and short-term planning criteria, were within the established guidelines. And the Deal A and Deal B transactions did not establish a "speculative" position that was beyond the guidelines.

Furthermore, if the Company had made an electric sale of the generated power from Deals A and B, it would have just <u>re-created the short open positions</u> that it had prior to entering into Deals A and B. Recreating the short positions would have exposed the Company and its customers to the high and volatile prices that were then present in the electric power market.

Therefore, it would not have been appropriate for the Company to sell the power it had just acquired to cover its short positions.

Q. On page 7, line 18 of his testimony, Mr. Hessing expresses concern regarding the risks associated with the "length of these gas purchase deals for its [Avista's] electric customers." Do you have any comments on this testimony?

A. Yes. As I explained earlier in response to Dr. Peseau, the medium-term natural gas transactions were designed to provide a firm supply of power to Avista's electric retail customers at fixed prices. Historically, Avista has regularly entered into medium-term fixed-price transactions of two to five years in developing its portfolio of resources to serve its electric customers. Many of these transactions have yielded substantial cost savings for customers, as explained earlier, and the length of the term is consistent with prior purchasing practices for Avista's electric portfolio.

Q. On page 16 of his testimony Mr. Hessing expresses concern that the use Avista Energy as a counterparty created a "potential conflict of interest." Do you have any comments on this testimony?

A. Yes. The Company recognizes that the use a subsidiary company such as Avista Energy as a counterparty may subject the transactions to a higher level of scrutiny. Avista believes that a careful review of these transactions is reasonable and appropriate. To that end, Avista was thorough in the filing of its direct case in providing information related to the Deal A and Deal B transactions, and has been very responsive to discovery questions related to these transactions in an effort to provide the information necessary for a thorough review.

As explained earlier, Avista Utilities sought out Avista Energy to enter into the Deal B transactions due to the non-standard term and limited counterparties willing to do the hedges. Avista Utilities evaluated those transactions in the same manner as the transactions with non-affiliated parties, as discussed in my pre-filed direct testimony. If the prices seem high, based on today's look-back at the transactions, it is not because the transactions were with an affiliated company, it is because the market prices were high at the time Avista Utilities locked in the prices. The level of the prices had nothing to do with Avista Energy being an affiliated company.

The information provided by Avista Utilities in this case includes supporting documentation of the forward price of natural gas at the time the Deal B transactions were completed. The documentation shows that the Deal B prices reflected the appropriate market prices at the time.

With regard to Mr. Hessing's reference to "lower of cost or market," the cost of the Deal B financial hedge transactions reflects the <u>cost</u> of natural gas at the time Avista Utilities chose to lock in prices. The <u>cost</u> of the transactions <u>was the market</u>. The utility determined that it was necessary to lock in the prices for a 17-month period, knew what the cost was, and at that time found the <u>cost</u> to be reasonable and appropriate.

Q. On page 19 of his testimony, Mr. Hessing recommends that $6,496,669 be removed from the PCA balance related to the Deal B hedge transactions. Do you agree with Staff's recommendation?

A. No. The amount of $6,496,669 associated with the Deal B transactions should not be removed from the PCA balance. The Deal B transactions were entered into to cover the Company's open financial positions. The Company believes that it was appropriate to hedge that portion of its natural gas portfolio as part of meeting load obligations given the high electric power prices present in the market at the time. The Deal B transactions were not "speculative." It would not have been appropriate to make a sale of the power generated from that natural gas because it would have re-created a short position for the Company. The Company's resource positions, including the Deal A and Deal B transactions, were within the guidelines established by its long-term planning criteria, and the shorter-term 18-month criteria under the Risk Policy. It was reasonable for the Company to lock in the cost of natural gas for electric generation at a price well below the market price of electricity to mitigate financial risk in a manner consistent with its planning criteria.

Q. If the Commission was to determine that a portion of the Deal B transactions should be disallowed, what is the maximum amount that should be considered?

A. Mr. Hessing recommends that $6,496,669 be disallowed for Deal B. The figure of $6,496,669 was calculated by multiplying the volume of natural gas in Deal B by the difference between the Deal B hedge price and the average selling price in each month of June 2002 through October 2003. Mr. Hessing's methodology appropriately excludes the gas that was used to generate electricity to serve retail load.

Another approach to calculating the losses on Deal B gas is to look at the amount that put the Company in <u>monthly</u> long positions greater than 150 aMW. The loss on the sale of Deal B gas would be determined by only looking at gas sales that put the Company beyond that limit. Calculating the losses on the sale of Deal B based on this methodology would result in a disallowance of $2,748,609 (Idaho allocation, 90% customer share). A spreadsheet showing that calculation is contained in Exhibit No. 24.

Another method to determine a disallowance related to Deal B is to include the loss on Deal B gas sales only when those sales were made with no corresponding electricity purchase. In many cases the Company purchased an equivalent amount of electricity when gas was sold, which was ultimately used to serve retail load. In these cases, the Company sold gas because it was more economical to purchase electricity than utilize natural gas-fired generation. These occasions, where gas was sold electricity was purchased, resulted in lower total power supply expenses, even though there was a loss on the sale of the gas. Excluding the loss on gas sales where there is a corresponding electricity purchase is similar to Mr. Hessing's methodology in that it does not include the loss on energy that was ultimately used to serve retail load.

Counting the loss on Deal B gas that was sold without the purchase of replacement electricity results in a disallowance of $3,995,846 (Idaho allocation, 90% customer share). The spreadsheet showing the calculation of this number is contained in Exhibit No. 25.

V. BOULDER PARK – RESPONSE TO MR. STERLING

Q. Beginning at page 35 of his testimony, Mr. Sterling indicates that Staff recommends a 10% disallowance of Boulder Park costs. Do you agree with Staff's recommendation?

A. No. Given the circumstances, generally stemming from the fast track design-build approach that the Company chose in order to bring small generation on line as quickly as possible, the Boulder Park project costs were managed reasonably by the Company.

On page 33 of his testimony, Mr. Sterling expresses concern that the project was not completed on the planned fast-track schedule. By the summer of 2001 the Western energy crisis began to subside, but Avista continued to face serious financial difficulties. With power available at significantly lower wholesale market prices, the Company chose to slow down the construction schedule on Boulder Park to preserve cash. While the earlier circumstances justified a fast-track construction schedule, the change in circumstances supported a change in the schedule.

Although Mr. Sterling references costs associated with other similar projects, he also notes on page 36 that "cost information for these types of engines is somewhat difficult to obtain because there are few utilities or public entities that have recently installed these types of units." We believe it is important to use great care in the use of general estimates of plant costs for comparisons due to the many factors that may cause the costs of one project to be different than another; such as emission control issues, sound abatement, and project-specific configurations related to the plant's location. While Mr. Sterling does not question the choice of Boulder Park as a resource, it was, nevertheless, somewhat unique, and therefore created unanticipated challenges during construction.

Q. Does that conclude your rebuttal testimony?

A. Yes it does.

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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-04-01 REBUTTAL EXHIBIT NO. 24 ROBERT J. LAFFERTY

FOR AVISTA CORPORTATION

(ELECTRIC ONLY)

Avista Corp.
Calculation of Loss on Deal B Gas Sales

Date	Average Position[1] (aMW)	Length Above 150[2] (aMW)	Length Above 150[2] (GWh)	Deal B Above 150[3] (dth/day)	Sale Price[4] ($/dth)	Deal B Loss[5] ($)
Jun-02	354	204	147	20,000	2.62	2,017,791
Jul-02	304	154	114	20,000	2.79	1,977,984
Aug-02	36	0	0	0	2.45	0
Sep-02	-17	0	0	0	2.68	0
Oct-02	0	0	0	0	3.20	0
Nov-02	115	0	0	0	3.67	0
Dec-02	177	27	20	4,461	3.84	296,086
Jan-03	99	0	0	0	4.01	0
Feb-03	179	29	19	4,795	4.19	240,454
Mar-03	255	105	78	17,476	4.42	850,493
Apr-03	173	23	16	3,794	4.09	215,359
May-03	333	183	136	20,000	3.71	1,410,466
Jun-03	427	277	199	20,000	3.94	1,229,500
Jul-03	329	179	133	20,000	4.43	966,236
Aug-03	60	0	0	0	4.36	0
Sep-03	3	0	0	0	4.48	0
Oct-03	27	0	0	0	4.25	0
					Total Loss[6]	9,204,370
					Allocated Loss[7]	2,748,609

1) System position including all fixed-price resources.
2) Length in position beyond Risk Policy 150 aMW quarterly long position limit.
3) Deal B natural gas purchases contributing to positions beyond 150 aMW.
4) Actual average monthly sale prices of Deal B natural gas.
5) Effective loss of Deal B sales given average purchase price of $5.985/dth.
6) Sum of Deal B losses.
7) Sum of Deal B losses adjusted for Idaho (33.18%) and PCA (90%) allocations.

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FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Avista Corp.
Summary of Savings Obtained by Selling Fixed Priced Gas, Jul 2002 - Oct 2003
Loss on Deal B Gas Sales

Line No.	Transaction Date	Deal Ticket	Delivery Months	Volume (dth/day)	Price ($/dth)	Power Purchases Related to Sale of Gas	Savings from not Generating	Total Loss on Gas Sales
1	8-Jan-02	G0270	Jul	10,000	$2.20	No purchases made related to sale of gas due to position length	$84,308	$1,174,900
2	3-Apr-02	G0366	Jul	5,000	$3.35	No purchases made related to sale of gas due to position length	$110,927	$408,425
3	4-Apr-02	G0370	Nov-Oct 03	5,000	$3.65	No purchases made related to sale of gas due to position length	$1,629,216	$4,611,625
4	5-Apr-02	G0372	Nov-Oct 03	5,000	$3.52	No purchases made related to sale of gas due to position length	$1,385,341	$4,868,375
5	18-Jul-02	G0515	Mar-Jun	5,000	$3.39	No purchases made related to sale of gas due to position length	$714,288	$389,250
6	19-Jul-02	G0516	Apr-Jun	5,000	$3.36	No purchases made related to sale of gas due to position length	$565,174	$393,750
7	30-Sep-02	G0655	May-Jun	10,000	$3.55	No purchases made related to sale of gas due to position length	$521,647	$730,500
8	9-Jan-03	G0823	Jun	5,000	$4.25	No purchases made related to sale of gas due to position length	$237,165	$260,250
9	10-Jan-03	G0827	Jun	5,000	$4.27	No purchases made related to sale of gas due to position length	$137,286	$257,250
10	5-Apr-02	G0373 & 374	Jul	15,000	$3.02	No purchases made related to sale of gas due to position length	$258,318	$1,377,563
11	17-May-02	G0432	Jul-Oct	5,000	$3.30	25 aMW Q3 02 @ $39.75/MW DT 2190 & Oct 02 @ $36.75/MW DT 2191	$663,172	$0
12	21-May-02	G0439	Aug-Oct	5,000	$3.06	25 aMW Aug 02 @ $39.50/MW DT 2200, Sept 02 @ $39.50/MW DT 2196 & Oct 02 @ $35.75/MW DT 2195	$528,362	$0
13	21-May-02	G0438 & 440	Nov	10,000	$3.65	50 aMW Nov 02 @ $35.83/MW DT 2194 & DT 2195 avg price	$219,948	$0
14	22-May-02	G0444	Sep-Oct	5,000	$3.12	25 aMW Sep 02 @ 37.95 DT 2202 & Oct 02 @ $35.90 DT 2194	$121,568	$0
15	23-May-02	G0446	Oct-Dec	5,000	$3.58	25 aMW Q3 02 @ $38.00 DT 2199	$172,755	$0
16	28-May-02	G0448 & 449	Oct	13,000	$3.03	75 aMW Oct 02 @ $35.00/MW DT 2204, 2205 & 2211 avg price	$73,392	$0
17	5-Jun-02	G0464	Dec	5,000	$3.81	25 aMW Q4 02 LL @ $30.50/MW DT 2217	$65,929	$0
18	19-Jun-02	G0485	July	5,000	$2.63	No purchases made related to sale of gas due to position length	$117,124	$520,025
19	20-Jun-02	G0488	Dec	5,000	$3.82	25 aMW Dec 02 LL @ $34.00/MW DT 2232	$72,304	$0
20	20-Jun-02	G0489	Nov	12,000	$3.54	25 aMW Nov 02 flat @ $33.50/MW DT 2231	$245,639	$0
21	15-Jul-02	G0509	Sep	22,000	$2.24	50 aMW Sep 02 @ $24.50/MW DT 2246 & DT 2251 avg price	$147,716	$0
22	15-Jul-02	G0510 & 511	Aug	30,000	$2.20	125 aMW Aug 02 @ $21.22/MW DT 2247, 2249, 2250, 2254, 2255 avg pr	$513,189	$0
23	13-Aug-02	G0543	Sep	3,000	$2.55	No purchases made related to sale of gas due to position length	$67,257	$309,150
24	10-Sep-02	G0604	Oct	4,000	$2.99	25 aMW LL Oct 02 @ $27.75/MW DT 2267	$16,995	$0
25	17-Sep-02	G0624	Dec	11,000	$4.02	No purchases made related to sale of gas due to position length	$193,453	$670,065
26	1-Oct-02	G0660	Nov	3,000	$3.73	25 aMW Nov 02 @ $34.50/MW DT 2276	$88,829	$0
27	1-Oct-02	G0661	Oct (3-31)	3,000	$3.48	25 aMW Oct 02 (4-31) @ $29.25/MW DT 2276	$103,693	$0
28	20-Nov-02	G0741	Dec	5,500	$3.97	25 aMW HL Dec 02 @ $36.60/MW DT 2293 & 25 aMW LL Dec 02 @ $31.40 DT 2294	$113,425	$0
29	18-Jul-02	G0515	Mar-Jun	5,000	$3.39	No purchases made related to sale of gas due to position length	$714,288	$1,582,950
30	19-Jul-02	G0516	Apr-Jun	5,000	$3.36	No purchases made related to sale of gas due to position length	$565,174	$1,194,375
31	15-Aug-02	G0552	Jan	5,000	$3.80	No purchases made related to sale of gas due to position length	$178,365	$338,675
32	15-Aug-02	G0553	Feb	5,000	$3.70	No purchases made related to sale of gas due to position length	$147,418	$319,900
33	15-Aug-02	G0554	Mar	5,000	$3.53	No purchases made related to sale of gas due to position length	$68,051	$380,525
34	30-Sep-02	G0655	May-Jun	10,000	$3.55	No purchases made related to sale of gas due to position length	$521,647	$1,485,350
35	30-Sep-02	G0656	May	10,000	$3.53	No purchases made related to sale of gas due to position length		$761,050
36	10-Oct-02	G0680	Feb	3,000	$3.93	No purchases made related to sale of gas due to position length	$67,430	$172,620
37	10-Oct-02	G0681 & 82	Jan	22,000	$4.02	50 aMW Jan 03 @ $39.10/MWh, DT 2279	$561,825	$0
38	20-Nov-02	G0743	Jan	3,000	$4.11	25 MW HLH Jan 03 @ $39.25/MWh, DT 2295	$88,313	$0
39	23-Dec-02	G0792	Feb	5,000	$4.64	75 MW HLH Feb 03 @ $41.25/MWh, DT 2316 & 2317	$178,272	$0
40	23-Dec-02	G0793	Mar	5,000	$4.47	50 MW HLH Mar 03 @ $41.25/MWh, DT 2314 & 2315	$175,831	$0
41	23-Dec-02	G0794	Apr	5,000	$4.09	2 - 25 MW HLH Apr 03 @ $39.00 & $39.50/MWh, DT 2321 & 2323	$136,243	$0
42	31-Dec-02	G0804	Feb-Apr	5,000	$4.15	25 MW HLH Mar & Apr 03 @ $41.25/MWh, DT 2325	$361,019	$0
43						25 MW HLH Mar 03 @ $42.25/MWh, DT 2324		
44	3-Jan-03	G0810	Feb	5,000	$4.45	75 MW HLH Feb 03 @ $41.25/MWh, DT 2316 & 2317	$151,672	$0
45	6-Jan-03	G0814	Feb	4,000	$4.19	25 MW HLH Feb 03 @ $41.25/MWh, DT 2318		$0
46						25 MW LLH Feb 03 @ $36.00/MWh, DT 2322		
47	9-Jan-03	G0822	Mar	7,000	$4.37	No purchases made related to sale of gas due to position length	$141,031	$351,540
48	9-Jan-03	G0823	Jun	5,000	$4.25	No purchases made related to sale of gas due to position length	$237,165	$260,250
49	10-Jan-03	G0827	Jun	5,000	$4.27	No purchases made related to sale of gas due to position length	$137,286	$257,250
50	14-Jan-03	G0831	Feb	3,000	$4.50	25 MW HLH Feb 03 @ $42.00/MWh, DT 2329	$10,851	$0
51	16-Jan-03	G0837	Mar	3,000	$5.00	25 MW HLH Mar 03 @ $45.00/MWh, DT 2335	$30,107	$0
52	25-Feb-03	G0859	Apr	10,000	$4.91	50 MW HLH Apr 03 @ $44.18/MWh, DT 2353 & 2355	$292,134	$0
53	7/18/2002	G0515	Jul-03	5,000	$ 3.39	No electric purchases made related to sale of gas due to position length.	$98,334	$402,225
54	3/20/2003	G0900	Aug 03	5,000	$ 5.04	25 MW HL @ $54.00 ,DT 2365	$75,106	$0
55	3/20/2003	G0901	Sep 03	5,000	$ 4.97	25 MW HL @ $53.50, DT 2366	$46,678	$0
56	3/20/2003	G0902	Oct 03	5,000	$ 4.90	No electric purchases made related to sale of gas due to position length.	$118,703	$168,175
57	3/24/2003	G0905	Jul 03	4,000	$ 4.92	No electric purchases made related to sale of gas due to position length.	$46,626	$132,060
58	3/25/2003	G0907 & 908	Jul 03	21,000	$ 4.813	No electric purchases made related to sale of gas due to position length.	$411,316	$762,755
59	4/10/2003	G0922	Aug 03 - Oct 03	1,500	$ 4.98	25 MW HL Aug 03 @ $49.25, DT #2407	$127,863	$0
60						25 MW HL Q3 03 @ $46.25, DT 2409		
61	4/16/2003	G0930	Aug 03 - Oct 03	3,000	$ 5.265	25 MW HL Aug 03 @ $49.25,DT 2047	$169,135	$0
62						25 MW HL Q3 03 @ $46.25, DT 2409		
63	5/14/2003	G0966 & 967	Aug 03	2,000	$ 2.745	25 MW HL @ $53.25, DT 2412	$13,162	$0
64						25 MW LLH Apr 03 @ $36.75/MWh, DT 2354		
65	**Total Power Supply Savings from Selling Gas**						$15,039,465	
66	**Total Loss on All Gas Sales**							$24,540,828
67	**Total Loss on Deal B Gas Sales**							$ 13,381,039
68	**Idaho Allocation (33.18%)**							$ 4,439,829
69	**90% PCA Customer Portion of Deal B Losses**							**$ 3,995,846**

Gas Sales Volume by Transaction by Month (dth/day)

Total Sales	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
10,000		10,000															
5,000		5,000															
65,000	5,000					5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
65,000	5,000					5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
5,000	5,000																
5,000	5,000																
10,000	10,000																
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21,000														21,000			
4,500															1,500	1,500	1,500
9,000															3,000	3,000	3,000
2,000															2,000		
622,000	40,000	40,000	40,000	40,000	40,000	40,000	41,500	40,000	40,000	40,000	40,000	40,000	40,000	40,000	21,500	19,500	19,500

Deal B Loss on Gas Sales by Month

al B Purchase Price	$5.985	$5.985	$5.985	$5.985	$5.985	$5.985	$5.985	$5.985	$5.985	$5.985	$5.985
ays In Month	30	31	31	30	31	30	31	31	28	31	30
Month	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03
	$0	$1,174,900	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$408,425	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$350,250	$0	$0	$0	$0	$350,250	$361,925	$361,925	$326,900	$361,925	$350,250
	$369,750	$0	$0	$0	$0	$369,750	$382,075	$382,075	$345,100	$382,075	$369,750
	$389,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$393,750	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$730,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$260,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$257,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$1,377,563	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$520,025	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$309,150	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$670,065	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$402,225	$389,250
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$393,750
	$0	$0	$0	$0	$0	$0	$0	$338,675	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$319,900	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$380,525	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$172,620	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$351,540	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Loss on Gas Sale	$2,751,000	$3,480,913	$0	$309,150	$0	$720,000	$1,414,065	$1,082,675	$1,164,520	$1,878,290	$1,503,000
Total Gas Sold	40,000	40,000	40,000	40,000	40,000	40,000	41,500	40,000	40,000	40,000	40,000
Average Loss on Gas Sale	$2.29	$2.81	$0.00	$0.26	$0.00	$0.60	$1.10	$0.87	$1.04	$1.51	$1.25
Deal B Loss on Gas Sale	$1,375,500	$1,740,456	$0	$154,575	$0	$360,000	$681,477	$541,338	$582,260	$939,145	$751,500

Total Deal B Loss	$13,381,039
Idaho Allocation (33.18%)	$4,439,829
0% PCA Customer Portion	**$3,995,846**

Exhibit No. 25
Avista, Lafferty, Rebuttal
Case No. AVU-E-04-1

Deal B Loss on Gas Sales by Month

al B Purchase Price		$5.985	$5.985	$5.985	$5.985	$5.985	$5.985	$5.985
ys In Month		30	31	30	31	31	30	31
Month		Jun-02	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$350,250	$361,925	$350,250	$361,925	$361,925	$350,250	$361,925
		$369,750	$382,075	$369,750	$382,075	$382,075	$369,750	$382,075
		$389,250	$0	$0	$0	$0	$0	$0
		$393,750	$0	$0	$0	$0	$0	$0
		$730,500	$0	$0	$0	$0	$0	$0
		$260,250	$0	$0	$0	$0	$0	$0
		$257,250	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$402,225	$389,250	$0	$0	$0	$0
		$0	$406,875	$393,750	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$754,850	$730,500	$0	$0	$0	$0
		$0	$761,050	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$260,250	$0	$0	$0	$0
		$0	$0	$257,250	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$402,225	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$168,175
		$0	$0	$0	$132,060	$0	$0	$0
		$0	$0	$0	$762,755	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0
Total Loss on Gas Sale		$2,751,000	$3,069,000	$2,751,000	$2,041,040	$744,000	$720,000	$912,175
Total Gas Sold		40,000	40,000	40,000	40,000	21,500	19,500	19,500
Average Loss on Gas Sale		$2.29	$2.48	$2.29	$1.65	$1.12	$1.23	$1.51
Deal B Loss on Gas Sale		$1,375,500	$1,534,500	$1,375,500	$1,020,520	$692,093	$720,000	$912,175
Total Deal B Loss	$13,381,039							
Idaho Allocation (33.18%)	$4,439,829							
0% PCA Customer Portion	$3,995,846							