DAVID J. MEYER
SENIOR VICE PRESIDENT AND GENERAL COUNSEL
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-4361

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 DIRECT TESTIMONY OF ROBERT J. LAFFERTY

FOR AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Robert J. Lafferty and my business address is 1411 East Mission Avenue, Spokane, Washington. My present position is Manager, Wholesale Marketing & Contracts.

Q. Please state your educational background and professional experience.

A. I began my career at Avista Corp. in 1974 after graduating from Washington State University with a Bachelor of Arts degree in Business Administration and a Bachelor of Science degree in Electrical Engineering. In 1979, I passed the Professional Engineering License examination in the state of Washington. Over the past twenty-seven years I have served in a variety of positions in engineering, marketing, and energy resources departments. Since March 1996, I have served in various positions in the energy resources area (electricity and natural gas) involving the planning, acquisition and optimization of energy resources. Since December 2003, I have served as Manager, Wholesale Marketing & Contracts where my responsibilities include acquisition and management of long-term electric resources.

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

A. My testimony will address the reasonableness and prudence of certain resource acquisitions made by the Company in 2000 and 2001. In my testimony I will explain the resource planning that led to the solicitation of resource proposals under an all resource Request For Proposals (RFP) process. I will explain the assessment of supply-side and demand-side resource alternatives and the prudence of the selection of Coyote Springs 2 (CS2) for the Company's supply-side resource portfolio and the selection of demand-side projects for negotiation. I will explain Company's decision to sell 50% of the project. I will also address the final construction costs and non-fuel operating costs associated with CS2. I will cover the prudence of the medium-term forward natural gas hedge transactions that were deferred from the Company's recent PCA case. I will explain the prudence of the acquisition of the Boulder Park generation project and the addition of a small combustion turbine to the existing Kettle Falls generation project.

A table of the contents for my testimony is as follows:

I am sponsoring the exhibits and schedules listed in the following tables for identification, which were prepared under my direction:

Exhibit # 6 - Coyote Springs 2 Generation Project

Schedule #	*Description*
1	2000 Resource Selection Process Report
2	1997 IRP Update (filed in July 2000)
3	Evaluation Process Flow Chart and Evaluation Guidance for RFP
4	Resource Selection Process – 2^{nd} Round Screening *(Confidential)*
5	2000 Request For Proposals
6	RW Beck – RFP Bid Analysis Review
7	Resource Selection Process – 3^{rd} Round Screening *(Confidential)*
8	Resource Selection Process - Additional Explanation
9	Resource Planning & Acquisition Documentation Index *(Confidential)*
10	Revenue Requirement Analysis – Top Projects *(Confidential)*
11	Coyote Springs 2 - Re-evaluation *(Confidential)*
12	CS2 GSU Failure - Steps Taken By The CS2 Partners *(Confidential)*
13	GSU Transformer Data
14	Coyote Springs 2 GSU Alternatives *(Confidential)*
15	Coyote Springs 2 – Budget to Actual Cost Comparison *(Confidential)*

Exhibit #7 - Issues Deferred From PCA Case No. AVU-E-03-6

Schedule #	*Description*
16	Natural Gas Purchase & Hedge Transactions – Graph *(Confidential)*
17	3-21-01 L&R - Critical Water
18	12-Month Rolling – Forward Electric-Gas Implied Heat Rate Spread
19	Forward Natural Gas Purchases – Apr. 2000 through Dec. 2001
20	Natural Gas Requirements for Avista Generation
21	Natural Gas Transaction Records for Medium-Term Purchases *(Confidential)*
22	High Electric Prices – Dec. 2000 – Articles
23	California Potential Blackouts - Apr/May 2001 - Articles
24	Federal Position - No Price Caps - May/June 2001 - Articles
25	Weekly Load Variability (By Month)
26	Load & Resource Position Summary - 90% CI
27	Forward Natural Gas Price Curves – April/May 2001
28	Medium-Term Power Purchases
29	Natural Gas Forward Price Information - Publications April/May 2001
30	Medium-Term Power Purchase - Articles
31	Position Reports - Hedge Transactions *(Confidential)*

Exhibit #8 - 2001 Boulder Park - Resource Addition

Schedule #	*Description*
32	Mitigating Measures Taken By Avista During 2001
33	Boulder Park – Initial Economic Analysis *(Confidential)*
34	Small Generation Projects – Rejected Projects *(Confidential)*
35	Boulder Park – Re-evaluation *(Confidential)*

Exhibit #9 - 2001 Kettle Falls CT – Resource Addition

Schedule #	*Description*
36	Kettle Falls CT – Initial Economic Evaluation and Re-evaluation

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

A. Yes. With regard to the Coyote Springs 2 generation project:

- I will show that the selection CS2 as a resource from the Company's 2000 all-resource Request For Proposal process was reasonable. I will show that the Company reasonably and fairly evaluated 32 proposals from 23 bidders, had a third party review and critique the dispatch and economic analysis models, and through a multi-step screening process selected CS2 as the supply-side resource.

- I will show that the Company's decision to sell 50% of the CS2 project to Mirant was reasonable given the financial challenges facing the Company. I will show that the Company reasonably and fairly evaluated proposals it received and chose a buyer that provided the best value to the Company.

- I will show that the Company took reasonable steps to bring the CS2 project to commercial completion as quickly as practical. I will show that the Company, along with Mirant as its CS2 partner, took reasonable steps to take control and manage the project in the aftermath of the Enron and NEPCO bankruptcies. I will show that the CS2 partners took reasonable steps to manage the issues surrounding the failure of one generator step-up unit (GSU) transformer, and to facilitate the timely repair of the second transformer, which was damaged in shipment. I will show that the CS2 project start-up delays were caused by events outside of the Company's control and could not have reasonably been foreseen.

- I will show that higher than expected costs associated with the CS2 project were directly related to the bankruptcies of Enron and NEPCO and the resultant loss of the fixed-price construction contract that the CS2 partners had with NEPCO, a subsidiary of Enron. I will show that the Company, as one of the CS2 partners, was reasonable in its management of the difficult situations caused by the Enron and NEPCO bankruptcies at a critical time in the construction process of the CS2 plant.

With regard to issues deferred from the PCA Case No. AVU-E-03-6:

- I will show that the Company's decisions to purchase index-based firm delivered natural gas for CS2, with delivery flexibility to provide fuel supply to other natural gas-fired generation projects, were reasonable and that the Company took appropriate steps to secure that gas in two transactions covering two distinct time periods with different start and end delivery dates.

- I will show that the Company's decision to fix the price of a portion of its index-based natural gas, by entering into four medium-term hedge transactions, was based on its need for resources to serve net system load. I will show that the hedge transactions yielded a lower cost of generated power compared to purchasing electric power in the market. I will also show that the hedge transactions were structured in a manner to provide a degree of diversity by using two distinct time periods with different start and end delivery dates.

- I will also show that the Company does periodically enter into medium-term power transactions, going forward seven or eight years into the future, as a normal course of business. While an after-the-fact analysis is not an appropriate measure for prudence, I will also show that, when taken as a whole, the Company has achieved significant benefits from entering into medium-term transactions.

With regard to the Boulder Park resource addition:

- I will show that the Boulder Park generating project was a reasonable addition to the Company's electric resource portfolio. I will show that, at the time of the decision during the "energy crisis," that there were several factors that made Boulder Park an appropriate alternative to a market purchase including economics, dispatchability and diversity of supply across six generating units.

- I will also explain that the Company reasonably managed project costs given the circumstances. I will explain that actual project costs were higher than expected due in part to the fast-track design and construction approach aimed at bringing the generation on-line quickly during the period of high power prices.

With regard to the Kettle Falls CT resource addition:

- I will show that the Kettle Falls CT generating project was a reasonable addition to the Company's electric resource portfolio. I will show that the Kettle Falls CT was economic compared to market alternatives at the time of the decision to acquire the resource. I will show that this generation project design, because of the re-use of waste heat from the CT in the Kettle Falls wood-waste fired generation project, allows the overall energy produced from the natural gas to be used more efficiently, thereby improving the overall project economics.

II. Coyote Springs 2 Generation Project

A. 2000 Resource Selection Process – Overview/Summary:

Q. Please summarize the events leading up to the issuance of a Request For Proposals (RFP) and the selection of the CS2 project by Avista Utilities.

A. The sale of the Centralia coal-fired generation project was completed in May 2000. The plan to replace the Centralia energy was a two-step process. First, the Company secured a medium-term power purchase contract, which was contingent on the ultimate sale of the project, which occurred in May 2000. The purchase provided for a three and one-half year delivery term beginning July 1, 2000 through December 31, 2003. The purchase was for 200 MW of capacity and energy in the first, third and fourth quarters of each year. The Company received 143 aMW of energy on an annual average basis through the contract. A contingent purchase was important because of the uncertainty of the sale being finalized. This medium-term power supply contract was included as part of the Company's resource portfolio in the Company's Power Cost Adjustment filing in Case No. AVU-E-01-1.

Second, in spring of 2000, the Company included the long-term replacement of Centralia in its assessment of its future need for resources. Those needs were presented in the Company's 2000 IRP, and the all-resource 2000 RFP was prepared and released to assess potential market alternatives for acquisition of 300 MW of capacity and energy on a long-term basis. Through its resource acquisition process, the Company ultimately selected CS2 as a supply-side resource and three demand-side proposals for negotiation.

Q. Please provide an overview of the resource selection process that resulted in the selection of CS2.

A. The resource selection process is explained in the "2000 Resource Selection Process Report" which is attached as Schedule No. 1 of Exhibit No. 6. This report covers the planning and determination of resource need and the evaluation and decision process for both supply and demand side resources. A timeline of the resource acquisition milestones is included as page 1 of the Schedule. The report outlines the many steps involved in the resource selection process, including:

1) Investigation by the Company into generation build options for later comparison to Request For Proposal (RFP) bids;

2) Development of a 1997 IRP Update in Spring 2000 that quantified the Company's need for resources (also referred to as the 2000 IRP);

3) Development of the all-resource 2000 RFP;

4) Solicitation of input from Commission Staff and other parties outside of the Company on the 2000 IRP and on both the demand-side and supply-side components of the all-resource 2000 RFP;

5) Filing of the 2000 IRP and the 2000 RFP with the IPUC; the Company received input from outside parties during the comment period and made modifications;

6) Company solicitation of comments from 22 specific potential bidders in addition to the Washington Commission's general request for comments;

7) The IPUC issued Order No. 28542 in Case No. AVU-E-08, in which the Company's 2000 IRP and all-resource 2000 RFP were filed, noting that approval was not necessary in Idaho but further stating that "the Company is commended for soliciting public input into its RFP process;"

8) Issuance of the all-resource 2000 RFP for 300 MW of capacity and energy;

9) Development of the criteria, processes and methods, including price and non-price factors, for evaluating both demand-side and supply-side resource alternatives which were reviewed with Commission Staff;

10) Review with Commission Staff, the Prosym™ hourly dispatch model and the economic model to be used by the Company to evaluate and compare supply-side resource proposals;

11) The initial pricing forecast supplied by Henwood Energy Services, Inc., which included over-build and under-build generation capacity addition scenarios, used in the dispatch modeling, economic evaluation and screening of supply-side resource options;

12) Receipt of the 32 proposals from 23 bidders for a total of 2,700 MW of resources in response to the all-resource 2000 RFP from a variety of supply-side and demand-side proposals (7 energy efficiency, 1 customer-owned emergency generation, 6 renewable, and 18 for supply or unit-contingent offers);

13) Initial supply-side resource screening process based on whether individual bids met the requirements of the 2000 RFP; three projects were dropped out; results reviewed with Commission Staff;

14) Second supply-side screening process using the dispatch and economic analysis models yielded a short-list of seven supply-side resource options; Avista included a combined cycle combustion turbine at Rathdrum as a Company-build option; analyses and results were reviewed with Commission Staff;

15) Third-party review and critique of supply-side resource dispatch modeling and economic analysis processes performed by RW Beck; the review indicated that the dispatch and economic modeling analysis performed by the Company was sound and reasonable;

16) Based on RW Beck recommendations, a second energy and capacity price forecast, including high and low scenarios, provided by RW Beck was used in further dispatch modeling and economic analysis of supply-side resource alternatives;

17) A third supply-side screening process for the short-listed resource options; CS2 was included as a second Company-build option;

18) Demand-side proposals were similarly moved through a multi-stage screening process;

19) The cost of demand-side resource options were measured against both the avoided cost of supply side options as well as against mutually exclusive internal and external DSM opportunities;

20) Review of the third screening of supply-side resources and final screening of demand-side resources with WUTC and IPUC Commission Staffs;

21) Company decision selecting CS2 as the supply-side option and accepting for negotiation three demand-side proposals.

Q. What preliminary work did the Company conduct in preparation for the selection of new long-term resources?

A. In the fall of 1999, the Company began gathering information regarding potential generation options and sites that could be available in the region. A comparative evaluation of potential base-load combined cycle combustion turbine sites was performed. The Company also contracted with Dames & Moore to provide a more formal site study of the top five generation sites. Their report was reviewed with the IRP Technical Advisory Committee (TAC) in June of 2000. The Company's existing Rathdrum simple cycle combustion turbine project was the preferred site for a combined cycle combustion turbine project. The site study provided a basis for Avista to later develop the preliminary engineering analysis necessary to determine costs for a "Company-build" option to compare to third-party proposals in the planned RFP process.

Q. What was the process used in the determination of the Company's need for additional resources?

A. A tabulation of the Company's loads and resources over the period 2001-2010 showed a long-term resource need of 300 MW of capacity and energy and the need for a base-load resource by year 2004. The Company used the Prosym™ hourly dispatch model, to assess the magnitude and duration of the net resource deficiency facing the Company under the 60 years of hydroelectric generation conditions using hourly data. These analyses demonstrated that a standard size 280 MW combined cycle combustion turbine would need to operate approximately 80% of the time to meet the 2004 resource need. The L&R tabulation and the 2004 Hourly Net Resource Position graphs filed with the Commission with the July 2000 IRP are included in pages 71 through 83 of Schedule No. 2 of Exhibit No. 6.

Q. **Please give an overview of the evaluation process used for the electric RFP bid proposals.**

A. Supply-side and demand-side resources were both subjected to a multi-step evaluation and screening process laid out in advance of opening the bids. These evaluation processes included both price and non-price factors. The "Avista Evaluation Guidance For Electric RFP Bid Proposals," dated September 15, 2000, is attached as Schedule No. 3 of Exhibit No. 6. At each screening, more detailed information was gathered and evaluated.

After a first screening to determine if proposals met minimum bid requirements, the supply-side evaluation process began with a dispatch analysis using Prosym™, an hourly production cost modeling tool, for each resource option. This portion of the analysis determined the least cost operation of the Company's total resource stack when the new resource was dispatched in combination with Avista's existing resources. The Prosym™ model was run with and without the resource proposal to determine the net change in system variable cost. In a second step in the evaluation, economic modeling was then performed using the differential variable system costs from the Prosym™ model output combined with the fixed costs of the resource analyzed annually over the life of the resource up to 25 years. In the third step, a team of Avista employees from different areas of expertise reviewed each supply-side bid alternative and jointly ranked each bid in price and non-price areas as defined in the Evaluation Guidance (Schedule No. 3). Resource alternatives were then ranked in an evaluation matrix based on the weighted evaluation factors laid out in the Evaluation Guidance document. A flow-chart of the supply-side resource evaluation process is shown on page 1 of Schedule No. 3 of Exhibit No. 6. Supply-side resource proposals went through the second and third screenings using this three-step evaluation process. "Weaker" proposals were screened out at each screening.

Q. What supply-side resources were considered in the short-list for further evaluation?

A. At the conclusion of the second screening, using the proposal rankings from the weighted evaluation matrix, seven projects were selected for more data gathering and more detailed evaluation. One turnkey combined cycle combustion turbine project, three market-based sales offers, one tolling proposal, one small hydroelectric generation project and one Company-build option were selected. The second screening weighted matrix evaluation and associated documentation is attached as Confidential Schedule No. 4 of Exhibit No. 6.

Q. What build options were included in the supply-side resources?

A. Avista's resource assessment included a Company "at cost" build option at Rathdrum which would increase the efficiency of the existing simple cycle combustion turbines through the addition of a heat recovery steam generator and a replacement of the existing peaking capacity with more efficient simple cycle natural gas combustion turbines. In addition to the short-listed projects from the second screening, Avista also chose to include, as an "at cost" proposal, the CS2 combined cycle combustion turbine project. Avista Power had acquired this project from Enron. These two Company sponsored projects were subjected to the same dispatch and economic evaluations as well as the same price and non-price rankings and weighted evaluation matrix analysis as other supply-side RFP proposals. The RFP states on page 1 of the document sent to bidders that resources bid to the Company "must be competitive with other resource options available to Avista, including resources available to the utility <u>at cost</u> from affiliates, in order to be considered for purchase." The RFP is attached as Schedule No. 5 of Exhibit No. 6.

Q. Did the Company have any independent review of its analyses of supply-side resources?

A. Yes. The Company retained RW Beck consultants to review and critique the Company's dispatch modeling and economic modeling analyses for a sample of eight different types of supply-side resource proposals. The resource proposals reviewed by RW Beck included combustion turbine tolling, market-supplied monthly dispatch, wind generation, small hydroelectric generation, and the Rathdrum self-build option. The review was performed between the second and third screening steps. The RW Beck "RFP Bid Analysis Review" is attached as Schedule No. 6 of Exhibit No. 6. The RW Beck report included the following assessment of the Company's analytical approach and methodology on page 7 of the Schedule.

> "Based on our review, R.W. Beck believes the approach taken by Avista in its analysis of the alternative resource proposals provides a fair comparison of the resource options including in the bid proposals or the self-build option. We believe that comparing Avista's total system cost with and without each of the resource options, and the net project benefit of each proposed resource, is a reasonable way to determine which options are the most financially and economically viable for Avista.

> Avista has used an adequate level of care to include the necessary assumptions and methodology in both the *Prosym*™ modeling of the bids and in the economic analysis spreadsheets. R.W. Beck did not find any material deficiencies (such as miscalculation of formulas or omission of essential data) in either the input files or the electronic spread sheet analyses."

The Company followed recommendations by RW Beck to use a market price forecast with a higher level of detail including hourly electric prices to use with hourly dispatch modeling, a forecast of both energy and capacity electric prices instead of forecasting an all-in price, and monthly natural gas prices instead of annual. The Company retained RW Beck to provide the more detailed pricing forecasts including scenarios for high and low natural gas prices and high Northwest load.

Q. What were the conclusions of RW Beck from their review of the Company's RFP bid analysis?

A. After their review of the Company's RFP bid analysis, RW Beck made the following conclusions:

- "Avista's bid evaluation methodology and assumptions were sound. Avista staff included all the necessary input variables into the *Prosym*™ model and the economic analysis spreadsheets."
- "R.W. Beck's recommended modifications to forecasted market prices were addressed in order to improve the bid review analysis. Avista was committed to creating a fair and accurate bid-review process and invested the required time and resources to do so."
- "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."
- "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. All bids reviewed were represented fairly in the *Prosym*™ model and the financial analysis spreadsheets."

Q. Please summarize the supply-side results of the RFP process.

A. The Company selected the 280 MW CS2 project near Boardman, Oregon as the preferred supply-side option. In addition to overall cost effectiveness, a key factor in selecting the CS2 project was that it included a fully licensed site. The major equipment had already been ordered and an Engineering, Procurement and Construction (EPC) contractor had already been selected for the project. At the time of the evaluation, these factors combined to make some major cost and timeline factors better known and therefore an advantage compared to Rathdrum, which was the second best alternative. The weighted matrix evaluation and associated documentation summary for the third and final screen is attached as Confidential Schedule No. 7 of Exhibit No. 6.

Additional details of the supply-side and demand-side resource selection process are explained in Schedule No. 8 of Exhibit No. 6.

The Company has extensive documentation of the complete 2000 IRP planning process and the RFP resource procurement process. The documentation is kept in a series of books and the index to those records is attached in Confidential Schedule No. 9 of Exhibit No. 6.

B. 2002 Coyote Springs 2 - 50% Sale of Project

Q. Did the Company re-evaluate its investment in CS2 as power market conditions changed and as the Company continued to have difficulty finding project financing for the project?

A. Yes. The western United States experienced unprecedented high wholesale prices from May 2000 through June 2001. The Company began construction of CS2 in January 2001. During the first half of 2001, and extending through the remainder of the year, Avista experienced the worst hydroelectric generation conditions on record. The combination of low water conditions and high market prices caused the Company to incur significant power purchase costs, which created serious financial challenges for the Company. As a result of these challenges, Avista was not able to complete construction financing for CS2.

Q. What options did the Company consider?

A. The Company considered two general options: 1) Sell the entire plant, and, if reasonable, purchase back approximately half of the plant output; or 2) Sell one-half of the plant and receive one-half of the plant output as a joint plant owner. The Company received confidential proposals from three parties. A dispatch analysis was performed for each proposal, and compared with replacement of the entire plant with a market purchase of energy. The economic analyses of those proposals are attached as Confidential Schedule No. 11 of Exhibit No. 6.

Q. Please describe the proposals in general terms and the results of the Company's economic analysis.

A. Two proposals included a complete purchase of the plant, but with the requirement that the Company enter into a 20-year tolling arrangement. Under a tolling agreement, the Company would be responsible for all O&M and fuel costs. In addition, the Company would pay a tolling or capacity fee. Mirant provided a proposal to pay one-half of the capital costs of the plant.

The Company performed analyses on the proposals that included the same monthly dispatch modeling, fixed and variable cost treatment, electric and natural gas transportation costing, and economic modeling as was used in the 2000 Resource Selection Process. The electric power and natural gas price forecasts were updated to reflect current near-term conditions. Beginning with the year 2003 and going forward, the Company used the RW Beck long-term price forecast for electricity and natural gas.

The Mirant proposal provided the best 20-year NPV. The Mirant proposal exceeded the next best proposal by nearly $8 million on a 20-year net present value basis. The sale of one-half of the plant also provided some relief for the Company's near-term financial situation.

The Company sold one-half of CS2 to Mirant on December 12, 2001. As part of the transaction, Mirant pays one-half of all capital costs and one-half of all operation and maintenance costs for the project. Mirant is responsible for securing its own natural gas supply and as well as paying for its own natural gas transportation costs. Mirant is also responsible for making its own arrangements for transmission to move electric power from the plant. The Company provides control area services to Mirant at CS2 under a separate agreement.

C. <u>2002-2003 Coyote Springs 2 – Project Start-Up Delays</u>

Q. Would you please provide a brief chronology leading up to the planned on-line date for CS2, and subsequent delays that occurred in bringing the plant on-line.

A. Yes. Avista Power, a subsidiary of Avista Corp., purchased the project site, design, permits and development rights for the CS2 project in July 2000 and selected NEPCO (National Energy Production Corporation) as the EPC contractor for the project.

In December 2000, Avista Utilities selected CS2 as a resource as part of its RFP process. Prior to that time, the permits and licenses necessary to construct the project had already been obtained. NEPCO had already been selected as the EPC contractor and major equipment had been ordered for the project. Construction on the CS2 project began on January 2, 2001. Enron filed for bankruptcy protection on December 2, 2001. The bankruptcy of Enron directly impacted the ability of NEPCO, an Enron subsidiary, to fullfill their contractual obligation to complete the CS2 project, resulting in both inreased costs and a delay in the construction of CS2. The CS2 project also later experienced difficulties with the generator step-up transformer which caused additional delays in the on-line date of the project.

Q. Please explain the impact of the bankruptcy of Enron and its subsidiary NEPCO on the CS2 project construction schedule.

A. Following Enron's bankruptcy on December 2, 2001, Enron ceased making funds available to NEPCO to pay vendors, equipment suppliers, craft, etc. to complete the CS2 project. Beginning on that date, Avista, and later the CS2 partners (Avista and Mirant), had to assume responsibility to pay directly all costs associated with the project, including engineering, procurement, and construction costs. On April 12, 2002, NEPCO declared bankruptcy. The CS2 partners stepped in and took over from NEPCO the role of CS2 EPC contractor. Black and Veatch was hired by the CS2 partners to assume responsibility for onsite construction management and oversight as well as for continuing engineering. The transition process included dismissing construction staff at the CS2 site and putting in place new management and construction staffing. The replacement of NEPCO added approximately two months to the project completion timeline, which was extended from the original target date of June 2002 to August of 2002.

Q. Please summarize the timing and circumstances surrounding the failure of the generator step-up unit (GSU) transformer?

A. On March 3, 2002 the GSU transformer was energized from the CS2 switchyard that is interconnected with the Bonneville Power Administration (BPA) 500kV transmission system. On May 6, 2002 the GSU transformer failed resulting in the spilling of 15,000 to 16,000 gallons of zero PCB mineral oil and a fire. The generators at CS2 were not operational during that time frame. The oil spilled into a concrete containment structure which is designed to contain more oil than the transformer holds, but because of the fire and the fact that the deluge system was activated to control the fire, more than 100,000 gallons of water was used to control and extinguish the fire. The oil and water mixture overflowed the containment and the water and oil mixture spilled onto the ground and flowed to an irrigation pond east of the project and onto the switchyard to the south. This spill was cleaned up in conjunction with the oversight of the Oregon DEQ.

Q. Was there reason to believe that there would be difficulties with the GSU transformer?

A. No. The three-phase GSU for CS2 was one of the major equipment components included as part of the original design for CS2. The transformer was specified as a single three-phase GSU with a high side voltage of 525kV and two low side windings of 13.8kV and 18kV. The GSU transformer was built by Alstom at their transformer factory in Gebze, Turkey. Alstom has over 100 years in the electrical equipment business and is one of the world's leading manufacturers of electric generation, transmission and distribution equipment. They have over 30,000 employees in more than 30 countries. Alstom has been manufacturing transformers up to 525 kV rated voltage and 400 MVA rated power in the Gebze plant for over 30 years.

When Alstom informed NEPCO that the GSU transformer passed all tests at the factory, it was shipped to the CS2 site. Prior to energizing the transformer, the transformer was filled with oil, from which a sample was taken and then tested by an independent testing firm. The transformer oil was tested for dissolved gases and passed. A number of electrical commissioning tests were successfully performed at the site as well.

Q. What steps were taken by the CS2 partners, Avista Utilities and Mirant, subsequent to the CS2 GSU failure?

A. The CS2 partners investigated several options including replacing or repairing the failed GSU. The CS2 partners investigated whether a compatible spare transformer might be available from another company and found none available. The CS2 partners also evaluated different transformer configuration options and found those to be more expensive and with longer delivery-times. The steps taken by the CS2 partners are summarized in more detail in Schedule No. 12 of Exhibit No. 6.

Q. What decision was reached regarding replacement of the CS2 GSU transformer and what was the reasoning behind it?

A. On June 13, 2002 the CS2 partners decided to purchase a second GSU transformer from Alstom. The major deciding factors were the shorter lead-time and lower cost for a new Alstom transformer compared to a new transformer from an alternate manufacturer. The CS2 partners had no reason to believe, given Alstom's extensive experience, that they would not produce a reliable GSU transformer.

Q. Will the CS2 partners be compensated for the failed transformer?

A. Work with the insurance company for the CS2 project is in progress. At this time the insurers have paid approximately $2.2 million for the replacement transformer and a portion of the costs to clean up the site due to the oil spill. The CS2 partners continue to work with the insurers with regard to additional payments. Avista's share is one-half of the insurance amount.

Q. What steps were taken to ensure that Alstom would supply a reliable transformer?

A. The CS2 partners took a number of steps, including a design review and hiring of an independent transformer expert and another transformer consultant to witness factory tests in Turkey, which are covered in more detail in Schedule No. 12 of Exhibit No. 6. After all factory tests were passed, the unit was shipped.

Q. Did any further issues arise concerning the second transformer?

A. Yes. The second transformer arrived at the CS2 site on December 15, 2002. After the transformer was moved onto its foundation, Alstom personnel performed an internal inspection and found that the fifth leg of the transformer core had been damaged. Alstom and CS2 representatives discussed the situation and agreed that the second transformer could not be repaired in the field and would need to be sent to a suitable repair facility.

Q. What alternatives were considered to determine the best approach to bringing CS2 on-line?

A. The CS2 partners identified eleven different alternatives to bring CS2 on-line expeditiously. Those eleven alternatives are described in a document entitled "Coyote Springs 2 GSU Alternatives" which is attached as Confidential Schedule No. 14 of Exhibit No. 6. Confidential Schedule No. 14 is a white paper that was completed by Avista and Mirant personnel in March of 2003. It covers a wide range of alternatives and includes several options to repair the second transformer and the possible purchase of multiple replacement transformers including the associated reconfiguration of the CS2 plant to accommodate a change to a multiple transformer arrangement. Several options also considered the potential repair of the original transformer as a spare.

Q. What decision was reached regarding repair or replacement of the CS2 GSU transformer and what was the reasoning behind it?

A. On December 20, 2002 the CS2 partners had agreed to move forward toward either repair or replacement of the transformer on two separate parallel paths. The CS2 partners made arrangements to take the initial steps to repair the second transformer.

Arrangements were therefore made to ship the second transformer to the Edison ESI repair facilities in California. The CS2 partners also began gathering the information necessary to further evaluate the eleven alternatives that are described in Confidential Schedule No. 14 of Exhibit No. 6.

Q. What was the result of the evaluation of the eleven alternatives outlined in Confidential Schedule No. 14 of Exhibit No. 6?

A. Confidential Schedule No. 14 summarizes the advantages, disadvantages, estimated costs, schedules, future outage time required to accomplish any necessary rebuild, and reliability implications of each of the alternatives. The assessment of the alternatives led the CS2 partners to proceed with the immediate repair of the second transformer.

Q. When was the repair completed and the GSU transformer placed into service?

A. On February 10, 2003 CS2 partner representatives and Alstom representatives met at the Edison ESI repair facility to observe the transformer untanked and to agree upon the repair procedure. On April 25, 2003 the second transformer passed the factory tests. The second transformer was shipped to the CS2 site and was energized on May 30, 2003. The transformer began carrying power from the CS2 generator on June 3, 2003. The CS2 project was made available for commercial operation on July 1, 2003.

D. Coyote Springs 2 – Final Construction Costs

Q. What was the Avista Utilities share of the total construction cost for the completed CS2 project?

A. The Company's share of CS2 construction costs, as of 9/30/03, was approximately $109 million. This figure includes the clean up associated with the transformer failure and the transformer replacement cost net of an estimated insurance receipt of $1.3 million (Avista's share).

As explained earlier in my testimony, the Enron bankruptcy on December 2, 2001 and the subsequent bankruptcy of NEPCO, the CS2 project EPC contractor, in April 2002 were major factors that impacted the CS2 partner's ability to manage and control costs on the project. Adding to those costs were expenses associated with the failure of the GSU transformer.

The Enron and NEPCO bankruptcies caused additional construction labor, subcontractor costs and engineering costs that were incurred as the CS2 partners were forced to take over the engineering, procurement, construction and management of the CS2 project. The Enron and NEPCO bankruptcies also caused the CS2 partners to lose the benefit of the EPC contract, which otherwise would have ensured that the project construction would be completed by NEPCO for the firm pricing terms contained in the contract, except for allowed changes.

Avista Utilities, in partnership with Mirant, made every effort to control costs and to bring the CS2 project on line as soon as possible.

Q. What was the projected cost of the CS2 at the time of the decision to select the project as part of the Company's All Resource RFP process?

A. The Company projected a cost to complete the CS2 project of approximately $188 million. This was the amount used in the final steps of the RFP evaluation process in December 2000. The Company's proportionate share of costs based on the sale of 50% of the project was, therefore, approximately $94 million.

Q. Did the Company, as one of the CS2 partners, take reasonable and reasonable steps to assume responsibility for the remaining engineering, construction and management of the CS2 project?

A. Yes. The CS2 partners brought in outside experts Black & Veatch in March 2002, in advance of NEPCO filing for bankruptcy to perform an on-site audit for the purpose of updating the CS2 project schedule and budget. On April 12, 2002, as NEPCO filed for bankruptcy, the CS2 partners, with the assistance of Black & Veatch, assumed the direct responsibilities for the CS2 project engineering, procurement and construction management. The CS2 partners had to retrieve project documents from NEPCO offices in Denver, Colorado. The CS2 partners had to work through the necessary workforce changes at the site, making personnel changes and linking construction workers up with new contractors, supervisors and superintendents on a going-forward basis. The impacts on the workforce added to actual costs by causing losses in productivity.

Without the benefit of the NEPCO fixed-price EPC construction contract to cap the project costs, the CS2 partners had to manage and pay directly the actual incremental labor costs and contractor costs necessary to complete the project. Those actual project costs were higher than the milestone payments that remained in the EPC contract. Confidential Schedule No.15 of Exhibit No. 6 provides an itemized comparison of the estimated cost for the CS2 project at the time of the RFP selection, with the current expected total cost for construction of CS2, including costs associated with the GSU failure. Page 2 of the Schedule, identifies many of the direct costs that the CS2 partners were forced to pay in order to complete the project, as a result of the loss of the fixed-price EPC contract with NEPCO.

E. <u>Prudence Criteria Previously Adopted By Commission</u>

Q. Has the Commission previously articulated criteria to be used in the determination of prudently incurred costs associated with resource acquisitions?

A. Yes. The Commission outlined its prudence standards or guidelines related to resource acquisitions in its Order No. 28876 in Case No. AVU-E-01-11, dated October 12, 2001, and its Order No. 29130 in Case No. AVU-E-02-6, dated October 11, 2002. The Orders state as follows:

Order No. 28876, Case No. AVU-E-01-11, dated October 12, 2001

> The Company's actions have been reasonable for a regulated utility with an obligation to serve and to provide reliable low cost power. Our duty is to assess the Company's actions based on the information available at the time that the decision was made. (Page 11)

Order No. 29130 in Case No. AVU-E-02-6, dated October 11, 2002

> In assessing the reasonableness of the Company's deferred costs we considered whether the Company's decisions based on the information available at the time were reasonable when made and whether the Company's attempts to control its costs were prudent. It would not be appropriate to use the review standard suggested by Potlatch and assess the Company's decisions from the perspective of perfect hindsight. (Page 14)

We believe the Commission has been clear in these prior orders that the determination of prudence is based on the information available at the time the decisions were made. The costs related to some decisions, when viewed with hindsight (after-the-fact), may appear to be unfavorable to the Company and its customers, while other transactions would be favorable. An after-the-fact analysis, however, is not appropriate in the determination of prudence.

The Company has provided extensive documentation in this filing, through testimony and exhibits, to present the facts and circumstances that existed at the time decisions were made.

The charge of the parties in this case is for each participant to put themselves in the shoes of the Company at the time the decisions were made. And at that time, based on the information that would have been known, the participant should assess whether the decision was a reasonable choice. Furthermore, it is important to recognize that in many cases, there is a range of reasonable choices that a Company can make.

As stated earlier, Avista Utilities, in partnership with Mirant, made every effort to control costs and to bring the CS2 project on line as soon as possible. The bankruptcy of Enron and NEPCO, as well as the failure of the GSU transformer, could not have been predicted or foreseen. The Company believes that the decisions and actions related to CS2 have been reasonable and prudent and that the costs associated with the project have been prudently incurred and should be approved for recovery.

F. **Coyote Springs 2 – Non-Fuel Operating Costs**

Q. What operating costs are expected for the Company's 50% share of the CS2 generating project?

A. The Company has signed an Operations And Maintenance Agreement with Portland General Electric Company (PGE), the operator of the Coyote Springs 1 generating plant, which is located directly adjacent to the CS2 project. Under that agreement, PGE will operate the CS2 plant under an agreement for the CS2 partners, on a shared costs plus a fee basis. The CS2 partners will benefit from lower staffing levels and other operating costs shared with PGE as opposed to separately staffing and operating CS2 as an independent generating project. PGE has provided the Company with a budget of the monthly operating costs for CS2. Also included in the non-fuel operating costs is the Company's share of expenses related to a major maintenance contract covering the turbine.

The Company's share of operating costs for the CS2 generating project is approximately $3.7 million. This amount represents the Company's 50% share in CS2. Approximately 32% of those costs are fixed costs and 68% are variable costs.

III. Issues Deferred From PCA Case No. AVU-E-03-6

A. Natural Gas Hedges and Risk Policy Issues

Q. What issues were deferred from the Company's 2003 PCA filing to this proceeding by the Commission in its Order No. 29377?

A. Two issues were deferred to this filing: 1) costs associated with "Deal A" natural gas hedge transactions and; 2) costs associated with "Deal B" natural gas hedge transactions. In conjunction with the Deal A and Deal B hedge transactions, the Company was asked to address its risk policy as it pertains to long-term fuel supply contracts greater than 18 months.

B. 2001 Natural Gas Purchases and Hedge Transactions

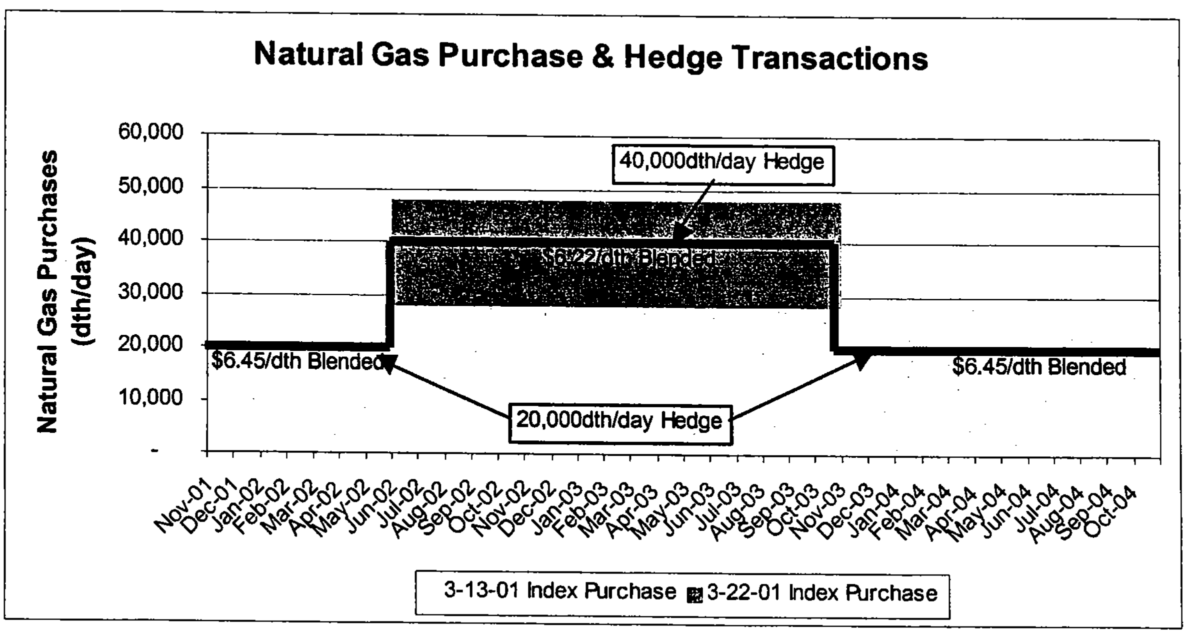
Q. Please describe "Deal A" and "Deal B" hedge transactions referenced in the Commission Order on Avista's 2003 PCA filing.

A. Commission Staff in their comments in the Company's 2003 PCA (Power Cost Adjustment) Case No. AVU-E-03-6 grouped together two pairs of hedge transactions based upon their delivery period and labeled them "Deal A" and "Deal B."

Deal A actually consists of two transactions of 10,000dth/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. 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.

Deal B actually consists of two hedge transactions of 10,000dth/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.

In the chart below the shaded areas illustrate the two index-based priced transactions for firm delivered gas that were entered into on March 13, 2001 and March 22, 2001. The lines on the chart show how much of that index-based priced natural gas was then hedged in the transactions that make up Deal A and Deal B. This chart, along with additional detailed information, is provided in Confidential Schedule No. 16 of Exhibit No. 7.



Q. What were the basic reasons underlying the Company's decision to enter into the two sets of hedge transactions labeled as Deal A and Deal B?

A. The Company was in a short position on an average basis for the periods of the natural gas hedge transactions. The Company had even shorter positions for certain key time periods such as the August through January periods, where supply and demand could be expected to be tighter.

In addition, the Company had concern for its short position exposure to the variability due to actual hydroelectric generation, actual loads, thermal generation outages, and contract obligations during the forward time period of high energy prices coupled with the potential for high price volatility. The combination of net system variability and high/volatile energy prices was a significant economic risk.

The Company, therefore, elected to hedge a portion (84%) of the index-based natural gas purchases that had been secured in March of 2001. As will be explained in more detail later, with the addition of CS2, the Company's natural gas-fired generation could consume approximately 101,310 dth/day of which 40,000 dth/day represents approximately 40% of that total. The amount of hedged natural gas covered the Company's net position deficits in most months based on average load and hydro conditions. The amount hedged also covered a portion of the monthly net position associated with the combined variability of loads and hydroelectric generation conditions.

The result was, that the Company's traditional critical water load and resource (L&R) tabulation shows an approximately even net position for 2002 and a slight surplus for 2003 when considering just the natural gas-fired generation for which the Company had acquired hedged natural gas. This L&R tabulation is provided in Schedule No. 17 of Exhibit No. 7. The year 2004 shows a substantial deficit primarily due to a major supply contract, which terminated at the end of 2003. The Company's surplus/(deficiency), including generation from the fixed-price gas contracts is summarized in the following table.

Period	Long/(Short) Position
January 2002 – December 2002	2 aMW
January 2003 – December 2003	35 aMW
January 2004 – December 2004	(256) aMW

Q. How did the cost of generation using the Deal A and Deal B natural gas compare with the forward price of electricity over the same time period?

A. The following tables briefly summarize the variable cost of the generation expected to use the natural gas fuel, including CS2, Rathdrum, Northeast, and Boulder Park, compared to the forward market price available at the time of the natural gas hedge transactions.

Coyote Springs 2

Deal	Transaction Date	Delivery Period	Volume (dth/day)	Gas Price ($/dth)	**Variable Generation Cost ($/MWh)**	**Mid-C HLH Price ($/MWh)**	**Mid-C LLH Price ($/MWh)**
B	4-10-01	June-02 - Oct-03	10,000	$6.56	**$46.06**	**$126.75**	**$105.38**
A	4-11-01	June-02 - Oct-04	10,000	$6.90	**$48.44**	**$108.89**	**$85.08**
A	5-2-01	June-02 - Oct-04	10,000	$6.00	**$42.16**	**$84.78**	**$61.46**
B	5-10-01	June-02 - Oct-03	10,000	$5.41	**$38.06**	**$100.99**	**$79.27**

Rathdrum

Deal	Transaction Date	Delivery Period	Volume (dth/day)	Gas Price ($/dth)	**Variable Generation Cost ($/MWh)**	**Mid-C HLH Price ($/MWh)**	**Mid-C LLH Price ($/MWh)**
A	4-11-01	Nov-01 – May-02	10,000	$6.90	**$83.85**	**$230.86**	**$212.53**
A	5-2-01	Nov-01 – May-02	10,000	$6.00	**$73.02**	**$187.86**	**$147.45**

Northeast

Deal	Transaction Date	Delivery Period	Volume (dth/day)	Gas Price ($/dth)	**Variable Generation Cost ($/MWh)**	**Mid-C HLH Price ($/MWh)**	**Mid-C LLH Price ($/MWh)**
A	4-11-01	Nov-01 – Dec-01	10,000	$6.90	**$94.73**	**$309.00**	**$271.92**
A	5-2-01	Nov-01 – Dec-01	10,000	$6.00	**$83.00**	**$254.00**	**$223.52**

Boulder Park

Deal	Transaction Date	Delivery Period	Volume (dth/day)	Gas Price ($/dth)	**Variable Generation Cost ($/MWh)**	**Mid-C HLH Price ($/MWh)**	**Mid-C LLH Price ($/MWh)**
A	4-11-01	Jan-02 – May-02	10,000	$6.90	**$67.64**	**$199.60**	**$188.78**
A	5-2-01	Jan-02 – May-02	10,000	$6.00	**$59.45**	**$161.40**	**$117.02**

As can been seen on the tables, hedging a portion of the Company's natural gas-fired generation portfolio provided a degree of price stability at a cost significantly below that of other alternatives available at the time. It was reasonable for the Company to not only cover its average net system position, but also a portion of its variable net system position during the time of high forward energy prices. The hedges allowed the Company to levelize the cost to generate power over two different delivery terms.

Q. Please describe how the relative market economics affect the operating plans of the Company's natural gas-fired generation.

A. As part of optimizing the use of its natural gas-fired generation, the Company may choose to secure fixed price gas supply in forward months depending on the spread ("implied heat rate[1]") between the price of natural gas and the price of electric power in those forward months. We will look at two examples for the Rathdrum combustion turbine, and for simplicity we will ignore non-fuel variable operating costs.

1) The heat rate of the Company's two Rathdrum combustion turbines is approximately 12,000 BTU/kWh. If a forward price for electricity is $100/MWh and natural gas price is $5.00/MMBTU, this represents a implied heat rate of 20,000BTU/kWh. The implied heat rate is well above the Rathdrum 12,000 BTU/kWh heat rate. Therefore, in this example, it is more economic to purchase gas at $5.00/MMBTU for the Rathdrum combustion turbines at the 12,000 BTU/kWh heat rate, and to generate electricity at $60.00/kWh, compared to purchasing power in the market for $100/MWh.

2) If the forward price for power is $30/MWh and the price for natural gas for the same period is $3.00/MMBTU, this represents a implied heat rate of 10,000 BTU/kWh. This implied heat rate is below the 12,000 BTU/kWh heat rate of the Rathdrum combustion turbines. Therefore, it is more economic to purchase electric power for $30/MWh than to purchase natural gas for the Rathdrum turbines. The cost to generate electric power would be $36.00/MWh at a natural gas price of $3.00/MMBTU.

Prior to year 2000, the forward implied heat rate between electric power prices and natural gas prices was not often high enough to warrant purchasing natural gas for future

[1] "Implied Heat Rate" identifies the marginal turbine that is supported by the markets for natural gas and electricity. The calculation of implied heat rate is performed by dividing the electricity price by the natural gas price and multiplying by 1000. For example, where the Mid-C price is $30 per MWh and the price of natural gas is $3.00 per dekatherm, the marginal operating unit would have a heat rate of 10,000 British thermal units per kilowatt-hour (Btu/kWh).

electric power generation given the 12,000 BTU/kWh heat rate of the Rathdrum plant. To the extent that the Company did not purchase natural gas in advance, it would then later, on a daily basis, evaluate whether to run the combustion turbines depending on the implied heat rate for that day.

For the period February 2000 through April 2000, the implied heat rate resulting from the natural gas and electric prices for a rolling one-year forward period (using monthly prices) averaged 11,232 BTU/kWh. In the period May 2000 through August 2001, the implied heat rate between natural gas and electric prices for a rolling one-year forward period (using monthly prices) averaged 28,229 BTU/kWh. Because the implied heat rate for this latter period was substantially greater than the 12,000 BTU/kWh, the Company acquired some forward natural gas for fueling the Rathdrum, Northeast, Boulder Park and Coyote Springs generation projects in place of purchasing more expensive power in the electric wholesale market. Schedule No. 18 of Exhibit No. 7 includes a graph illustrating how the rolling 12-month calculated implied heat rate between natural gas and electric forward prices changed over the period from January 25, 2000 through November 12, 2001.

In April 2000, the Company began purchasing monthly forward natural gas because the implied forward heat rate had increased to a level where it was more cost-effective to purchase natural gas for generation than to purchase power. A table of all of the Company's monthly forward purchases of natural gas for its natural gas fired generators for the period April 2000 through December 2001 is attached as Schedule No. 19 of Exhibit No. 7. The table lists the natural gas purchased in the period, the price per dekatherm, the equivalent electric price per megawatt-hour from operation of Rathdrum, Northeast, Boulder Park, and

CS2 generation projects, and the comparable forward price of electric power available for purchase at the time the natural gas was purchased.

Q. Please describe how the addition of CS2 affected the Company's acquisition of natural gas for generation?

A. CS2 is designed as a base load plant. It is significantly more efficient, at a 6,952 heat rate, than any of the other natural gas generation operated by the Company. As shown on the table of forward natural gas fixed price purchases, in Schedule No. 19 of Exhibit No. 7, the variable generation cost for CS2 was significantly below the forward price for electric power for the same period.

With the addition of CS2, the Company had natural gas-fired thermal generation that could consume approximately 100,310 dth/day (based on 100% Avista ownership). By comparison, the Deal A and Deal B natural gas included 20,000 dth/day for a 19-month delivery period and 40,000 dth/day for a 17-month delivery period. The graph contained in Schedule No. 20 of Exhibit No. 7 shows the average maximum daily natural gas consumption by generation project for a one-year period, based on permitted operating hours. The annual maximum average daily natural gas requirements for each of the Company's natural gas-fired generation plants are tabulated on page 2 of Schedule No. 20 of Exhibit No. 7.

In addition, financial institutions that were considering providing the long-term financing needed for the CS2 project required that the Company secure firm delivered fuel for the project prior to financing. As discussed in more detail later in my testimony, the purchase of firm index-based natural gas satisfied the fuel requirement for project financing.

Q What steps did the Company take to secure firm delivered natural gas supply?

A. With the addition of CS2 as a resource, it was necessary for Avista to secure a firm delivered natural gas supply for the project for operations purposes and also to satisfy project finance lenders that were requiring a firm fuel supply be secured prior to finalization of a financing arrangement. In making these arrangements, Avista also took into consideration the ability to flexibly delivery the natural gas to its other gas-fired plants (Rathdrum, Boulder Park and Northeast). The Company further considered the benefit of having the natural gas delivery at a liquid trading hub, such as Malin, in order to allow for sales of the natural gas as the dispatch economics dictated.

The Company took a series of steps in the first half of 2001 to secure the firm natural gas supply for CS2 and secure long-term natural gas transportation for CS2.

1) In January 2001, the Company made an inquiry for existing available firm natural gas transportation with Pacific Gas & Electric Gas Transmission Northwest (PG&E GTN) beginning in June 2002. PG&E GTN indicated that while there was no currently unsubscribed, firm, year-around transportation capacity available, they were planning to conduct a limited open season offering of firm transportation capacity in first quarter 2001, and depending on the response, they might later conduct an unlimited open season offering.

2) In first quarter 2001, PG&E GTN conducted a limited open season offering 200,000 dth/day of new capacity on their natural gas transmission line from the Canadian border to the California-Oregon border with an in-service date of November 2002. PG&E GTN indicated that they received interest from potential users for <u>ten times</u> the available new capacity. The Company participated in the limited open season but was unsuccessful in its bid for new capacity under that offering.

3) In March 2001, through two negotiated transactions, the Company contracted for firm natural gas deliveries, including firm transportation, on the PG&E GTN line from the Canadian border to Malin, at the California-Oregon border, for approximately 47,658 dth/day at a floating monthly index-based price plus

an adder. This represented 47% of the Company's natural gas portfolio and enough firm natural gas supply to operate the CS2 plant including the duct burner. The natural gas could be delivered at several points on the interstate natural gas transmission line between the Canadian border and the California-Oregon border at Malin. The Malin delivery point is an active marketing point where the Company can sell natural gas when the plant is not running. The combination of these factors gave flexibility in the use of the gas including using the gas at Rathdrum, Boulder Park and Northeast generation projects. The term of one transaction for 27,658 dth/day was November 1, 2001 through October 31, 2004. The term of the second transaction for 20,000 dth/day was June 1, 2002 through October 31, 2003. During the period November 1, 2001 through May 31, 2002, gas supplies were available for use either at peaking projects, such as the Rathdrum, Boulder Park or Northeast, or for use as CS2 test gas. Once CS2 began operation, it would have the best heat rate of the natural gas generation available to the Company, and gas supplies would be most efficiently used at that project. Purchase of firm delivered index-based natural gas satisfied the fuel requirement for project financing.

4) In June 2001, the Company participated in a second open season for pipeline capacity conducted by PG&E GTN. This open season was for unlimited expansion. The Company made a request and, on June 19, 2001, signed a Precedent Agreement with PG&E GTN for 33,000 dth/day of firm delivery at CS2. Upon the sale of 50% of the CS2 plant to Mirant in December 2001, this transportation capacity was proportionately allocated consistent with the plant sale with the Company retaining 16,500 dth/day. The PG&E GTN transportation capacity, combined with the corresponding capacity on gas systems in Canada, became available to the Company on November 1, 2003.

5) In combination with the above transportation capacity, the Company will utilize 5,000 dth/day of firm transportation capacity on PG&E GTN under existing contract rights beginning November 1, 2004. This transportation capacity will be reassigned from the Company's core natural gas business. The capacity is currently being held in the core portfolio to cover peak day load growth and is currently used for capacity release and off-system sales of natural gas. The resulting 21,500 dth/day of firm transportation is sufficient to operate Avista's share of CS2 without the duct burner. The Company will purchase delivered short-term gas when operating the less efficient duct burner.

Q. What further steps did the Company take with regard to natural gas supply?

A. As explained earlier, in April and May 2001, the Company hedged, or fixed the price, of 20,000 dth/day for certain time periods and 40,000 dth/day for other time periods (Deal A and Deal B). 40,000 dth/day represents approximately 40% of the Company's annual natural gas portfolio and 84% of the gas purchased at index-based prices.

Attached as Confidential Schedule No. 21 of Exhibit No. 7 are the transaction records for the index-based natural gas purchases and the financial hedges purchased to fix the price on a portion of the index-based natural gas. Also included is information regarding the natural gas and electric prices at the time of the transactions.

By fixing a medium-term price for natural gas, the Company was able to acquire natural gas for a lower price in the near-term and to levelize costs over a longer time frame. Natural gas prices in the winter of 2000-2001 demonstrated that they could become both quite high and volatile. The natural gas price at Malin for the month of December 2000 was \$14.42/dth and for January, February and March of 2001 were \$13.89/dth, \$10.03/dth and \$8.97/dth respectively. Malin daily prices exceeded \$49.00/dth on several days during December 2000. In addition to the recent winter's experience with volatile natural gas prices, the forward natural gas prices for the upcoming 2001-2002 winter season were high. On April 10, 2001 the forward price for Malin for the November 2001 through March 2002 delivery period was offered at \$11.365/dth in the market.

Q. What factors did the Company consider in fixing the price of a portion of the medium-term natural gas hedge transactions?

A. The Company considers several factors in its resource decisions, including, but not limited to: the forecast of loads and resources and the net system requirements;

forward variability of loads; forward variability of hydroelectric generation; forward market electric and natural gas price curves; the cost to generate electric power through the most economic available generator in the Company's resource stack; counter-party credit restrictions; point of delivery and liquidity (number of viable counter-parties able to transact); actual prices available from viable counter-parties; fit of the transaction within standard market product terms and conditions; and volumetric net position limits contained in the Company's Risk Policy. Changes in any of these factors can influence the decision to purchase or sell natural gas or electric power. No single factor will drive the Company's decision.

Q. How did the Company take into account its obligation to serve its load and resource net system position during the period of high energy prices?

A. During the energy crisis, in addition to planning to meet average net system obligations with fixed price resources, the Company placed additional weighting on the risk and economic impact created by the variability in both loads and resources combined with the high forward electric power prices and the associated high volatility conditions that were evident at the time.

Q. Please describe the circumstances surrounding the energy markets during the January through May 2001 time frame when the Deal A and Deal B transactions occurred.

A. The winter of 2000-2001 had demonstrated extreme price spikes in the near-term markets, as well as unprecedented high price in the forward markets. The highly volatile electric power market magnified the financial risk associated with variability in the

Company's resource and load obligations. Northwest power prices for December 2000 for daily purchases traded as high as $5,000/MWh, as shown in an excerpt from the December 11, 2000 Megawatt Daily, attached as page 1 of Schedule No. 22 of Exhibit No. 7. Page 2 of Schedule No. 22 includes an excerpt from the same report and states that "the balance-of-the-month sold for $2,000 at Mid-C and January sold for $800 for a third consecutive day."

Conditions in California in the upcoming summer of 2001 appeared to have the potential to create similar shortage-based extreme price spikes. Schedule No. 23 of Exhibit No. 7 includes several articles from the April 20, 2001 through May 6, 2001 timeframe where 34 to 44 days of rolling blackouts were being predicted for California electric customers in the upcoming summer months. The continued fall-off in available hydroelectric generation in the Pacific Northwest during 2001 caused further concerns that shortage conditions and the resultant high and volatile electric price conditions would continue at least through the winter 2001-2002. The Company also had concerns about 2002 hydroelectric generation conditions given the likelihood of low reservoir conditions and depleted groundwater conditions coming out of 2001.

The forward power prices were high at the time and there was no indication that federal policy makers would step in to mitigate price. Schedule No 24 of Exhibit No. 7 includes several articles from the May-June 2001 timeframe clearly indicating that federal policy-makers did not intend to implement price caps as a means to address the high prices in the western states. On May 31, 2001, Megawatt Daily reported that President Bush, in a speech at the World Affairs Council in Los Angeles "explained his opposition to price caps." "We will not take any action that makes California's problem worse, and that's why I oppose price caps," Bush said. "Price caps do nothing to reduce demand, and they do nothing to increase supply. This is not only my administration's position, this was the position of the prior administration." It was the Company's view that while electric power prices remained high, the potential for electric price volatility would continue.

The Company expected that the associated electric power price volatility could occur at any time throughout the period of high forward electric prices.

Q. What are some of the components of variability in resources and loads to which the Company is exposed?

A. The Company is exposed to variations in retail load, variations in hydroelectric generation, and variations created by unplanned outages of generation units.

The Company is also exposed to variability in contracts that contain options which counter-parties can exercise allowing them to call on power supplies at high strike prices. Under normal power pricing conditions those contract features were generally not economic to exercise. But, during the time of high electric market prices, counter-parties were looking at all opportunities to secure power at prices lower than market. An example is as discussed at page 8 of Witness Norwood's testimony in Case No. AVU-E-02-6, in which case the Bonneville Power Administration (BPA) called upon over 200,000 MWh of energy in the months of January through April and June 2001, to be provided by Avista at a price based on the operating costs of the Northeast Combustion Turbines, as allowed under the WNP #3 Settlement Agreement[2].

[2] At pages 16 through 17 of Witness Norwood's direct testimony in Case No. AVU-E-02-6, the Company explains that through negotiations, the Company was able to defer delivery of the WNP#3 return energy until Q4 of 2001. The result of deferring delivery of the energy yielded a benefit of $44.8 million on an actual basis.

During 2001, the Company experienced the worst hydroelectric generation conditions on record. Hydroelectric generation was 181 aMW below normal conditions in 2001.

Failure of either of the Colstrip Units #3 or #4 represents a potential net position variability of approximately 100 aMW for the period of the outage.

Under extreme market conditions the risk and economic impact of variability can be very high. At an 80% confidence interval[3] the Company's weekly loads can vary from the average by up to 87 aMW. Schedule No. 25 of Exhibit No. 7 shows, at an 80% and a 95% confidence interval, how much weekly loads have varied historically in each month of the year. If the Company were to have to purchase 100 aMW of additional power for only one week at a price of $500/MWh, the cost to the Company would be $8.4 million.

Each of the net position variability components had the potential to create significant financial impacts during the future period in which forward electric power prices were very high and potentially very volatile.

Q. Please explain what assessment the Company conducted relative to its exposure to net position variability?

A. In March 2001, the Company had performed Prosym™ hourly model analysis of monthly net positions for the 2002 – 2004 period. The 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 hydroelectric generation and load using both a 90% and a 95% confidence interval.

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[3] Confidence Interval – Represents the probability of the hydro-load variability staying within a specific MW range. For an 80% CI, there is a 10% chance that the Company would have to purchase some amount of energy above a specific MW amount for a given month. Similarly, a 90% CI represents a 5% chance of energy exceeding a specific MW amount

Page 1 of Schedule No. 26 of Exhibit No. 7 shows a graph of the analysis of the monthly 90% confidence interval net position analysis that has been adjusted to show the energy from Avista's resources excluding natural gas-fired generation. This graph, therefore, illustrates the system net position prior to executing either Deal A or Deal B hedge transactions. Significant deficits are present, particularly through the volatile August through January periods. The graph shows 90% confidence interval net position energy average deficits for the following periods:

Period	Long/(Short) Position
January 2002 – December 2002	(235) aMW
January 2003 – December 2003	(230) aMW
January 2004 – October 2004	(410) aMW

Q. Please explain how the Deal A and Deal B hedge transactions reduced the Company's exposure to net position deficits including a portion of its exposure to net system variability?

A. The combination of the Deal A and Deal B hedges reduced the Company's net position exposure based on 90% confidence interval planning. However, the Deal A and Deal B hedge transactions did not completely cover the Company's exposure to the 90% confidence interval net position variability related to load and hydroelectric generation conditions. As was stated earlier in my testimony, it was the Company's plan to cover at least a portion of the monthly net position associated with the combined variability of loads and hydroelectric generation conditions.

Page 2 of Schedule No. 26, again using the analysis performed in March 2001, shows a graph of the 90% confidence interval monthly net position data which has been adjusted to include the hedged portion of natural gas fired generation for Deal A and Deal B, beginning January 1, 2002 through October 31, 2004. The net position graph is shown separately for Deal A and Deal A + Deal B. A summary of the net system positions, including generation from Deals A and B, is as follows:

Period	Long/(Short) Position
January 2002 – December 2002	(84) aMW
January 2003 – December 2003	(10) aMW
January 2004 – October 2004	(310) aMW

Therefore, with generation available from Deal A and Deal B natural gas, the Company covered a portion, but not all, of its exposure to volatile wholesale prices.

Q. How does this analysis compare with the traditional critical water hydroelectric generation planning view?

A. As stated earlier in my testimony, the Company's traditional critical water load and resource (L&R) tabulation (Schedule No. 17 of Exhibit No. 7) shows an approximately even net position for 2002 and a slight surplus for 2003 when considering just the natural gas-fired generation for which the Company had acquired hedged natural gas. The year 2004 shows a substantial deficit primarily due to a major supply contract, which terminated at the end of 2003. The results are summarized in the following table.

Period	Long/(Short) Position
January 2002 – December 2002	2 aMW
January 2003 – December 2003	35 aMW
January 2004 – December 2004	(256) aMW

Q. What other factors were considered in association with the hedge transactions?

A. Another important factor when considering the hedge transactions was the comparative analysis of the cost to generate power at the hedged price of gas compared to electric power prices available at the time. Tables on pages 32 through 33 of my testimony summarized those comparisons showing that the hedged natural gas fuel resulted in generation costs in the range of approximately $38/Mwh to $48/MWh for CS2 and $59/MWh to $95/MWh for the less efficient generation units. These costs to generate were substantially lower than the high-priced power available in the market. The Company determined that these were reasonable costs at which to cover both deficits in its average net system position as well as a portion of those deficits resulting from variability in its loads and hydroelectric generation when compared to the risks of relying on the volatile electric power market.

Another factor considered in the decisions to hedge natural gas prices was that the Company could lower the near term cost of natural gas by purchasing a longer term hedge and thereby levelize a portion of its generation expense.

An additional factor considered in the hedge transactions was to structure transactions with different delivery terms, as well as substantially different start and end dates as a way to diversify the overall medium-term fuel portfolio. The delivery term for Deal B was 17-months vs. Deal A which was 36-months.

In summary, as a result of all of the various factors considered, the Company elected to cover a portion of the combined variability in its net resource position due to hydroelectric generation and load variability.

Q. Were either Deal A or Deal B natural gas purchases performed to "speculate" on the high spark spread and high electric power prices that were present at the time of the transactions?

A. No. The Company's purpose was to fix the price of a portion of its natural gas resource portfolio and to secure some protection from the high and volatile electric power prices.

Q. In its comments on the Company's 2003 PCA case, Commission Staff suggests that the Company, in retrospect, should have mitigated risk associated with Deal A and Deal B by securing some mechanism to lock in a power sale for what they viewed as "excess energy." Could you please explain the Company's position with regard to Staff's view?

A. Yes. As discussed in my testimony, the Company chose to cover its average net load and resource deficits as well as some portion of its exposure to load and hydroelectric variability for the Deal A and Deal B delivery periods with fixed-price natural gas for generation. The Company believes it was appropriate to hedge that portion of its natural gas portfolio as part of meeting load obligations given the high and volatile prices present in the market at the time. Notwithstanding the above, the Company had some concerns about making firm commitments from a project under construction with a completion date a year away. As stated earlier, the natural gas that was hedged in Deal A and Deal B could be used to fuel the Company's other natural gas-fired resources if CS2 was not available. For example, given the same 40,000 dth/day natural gas input, the Rathdrum project generates approximately 102 aMW less than CS2 because Rathdrum is a simple cycle design. Therefore, the additional risk was that the Company's net load and resource position would be reduced by approximately 102 aMW for those months where circumstances caused a reassignment of the hedged natural gas to the Rathdrum generation project.

Q. Were either the length of the term or the distance into the future of the deliveries of natural gas unusual?

A. No. The Company from time to time does purchase medium-term power, or in this case natural gas for electric power generation, as part its overall resource portfolio. To the extent that the Company has a portion of its load obligation relying on the short-term energy resource market, it may reduce that dependence on the short-term market, and thereby further diversify its portfolio, through either the acquisition of a medium-term electric power purchase or a medium-term natural gas purchase for generation of electric power, depending on which is more economic.

Q. Please describe the factors the Company considers when deciding whether to rely on purchases in the short-term resource market (one year or less) or whether to acquire a medium-term resource (one to five year term) in the form of either electric power or natural gas for generation of electric power.

A. The same set of resource acquisition decision factors covered earlier in my testimony also applies to the acquisition of medium-term resources, such as the forecast of loads and resources and the net system requirements, forward variability of loads, forward variability of hydroelectric generation, forward market electric and natural gas price curves, and the cost to generate electric power through the most economic available generator in the Company's resource stack.

Q. What are the benefits of making a medium-term resource acquisition compared to the alternative of relying on the short-term market?

A. A medium-term energy resource acquisition provides an opportunity to diversify a portion of the Company's resource portfolio that would otherwise be exposed to the short-term market conditions. A medium-term transaction provides a component of price stability and predictability for that portion of the Company's resource portfolio. When the forward price curve is high in the near-term and trends lower into the future, a medium-term resource purchase also provides an opportunity to reduce the near-term power costs and to levelize costs over a period of time. Conversely, when the forward price curve is low in the near-term and trends higher into the future, a levelized power price provides an opportunity to some degree to extend the benefits of the lower prices over the term of the agreement.

Q. Describe the Company's recent history of entering into medium-term transactions?

A. As part of building its forward resource portfolio, the Company will acquire electric power into the future for contract terms of one to five years and for time periods that may extend up to seven or eight years into the future. While not an appropriate measure for judging prudence, the Company has prepared a current analysis of the benefits of recent medium-term transactions.

Page 1 of Schedule No. 28 of Exhibit No.7 lists 175 MW of medium-term electric power purchases that were acquired prior to the year 2000 and were in place during the period of high electric prices from July 2000 through June 2001. The spreadsheet shows a net benefit of $227.5 million from these medium-term transactions when compared to the actual market conditions.

The Company also entered into a 200 MW medium-term power purchase contract in October 1999 for the purchase of electric power for the first, third and forth quarters of each year for a three and one-half year term beginning July 2000. Page 2 of Schedule No. 28 shows measurable after-the-fact net benefits from that contract during the July 2000 through December 2003 period of $236.7 million.

Pages 3 through 5 of Schedule No. 28 lists electric power transactions that the Company has also entered into for medium-term contracts totaling 125 MW for three and four year terms for delivery in the in 2004 - 2006 and the 2007 - 2010 time frames. The mark-to-market valuation of those purchases shows a net benefit of approximately $46.3 million compared to forward market prices as of January 14, 2004. In each of these cases, the Company entered into medium-term transactions, as part of its portfolio of resources, to provide some price stability for its total resource costs.

At the time of the natural gas hedges, the transactions were economic compared to market alternatives. However, as with all forward transactions, the market conditions at the time of delivery will undoubtedly be different from what they were at the time the transactions were executed.

As discussed earlier in my testimony, on an after-the-fact basis, the economics of a transaction may either be better or worse than at the time of the transaction. While after-the-fact comparison is not the appropriate measure for prudence, when taken as a whole, the Company has achieved significant benefits from entering into medium-term transactions.

It would be inappropriate to select one set of medium-term transactions (Deals A and B) and disallow recovery of the costs based on an after-the-fact analysis that shows that the price paid is greater than the short-term market prices. The reasonableness of the decisions/transactions should be based on the reasonableness of the transaction given the information and the circumstances at the time the deals were done. Recognition should also be given to the fact that, <u>over time</u>, some medium-term transactions will be favorable and some unfavorable, when viewed with hindsight.

In the case of Deals A and B, we believe the transactions were reasonable given the information and circumstances at the time. In addition, the Company has entered into many other medium-term transactions, as identified above, that have yielded substantial benefits to customers, when viewed with hindsight. Therefore, recovery of the costs associated with Deal A and Deal B is appropriate and reasonable.

Q. With regard to management of its electric resource portfolio, does the Company treat the acquisition of fixed-price natural gas for generation of electric power the same as the purchase of fixed-price electric power?

A. Yes. The Company may purchase fixed-price electric power or acquire fixed-price natural gas for generation, and in either case the electric power made available through the transaction is incorporated in the resource portfolio in the same manner.

Q. Does the Company's Energy Resources Risk Policy allow for medium-term purchases of electric power or natural gas for generation?

A. Yes. The Risk Policy contemplates that medium-term resource acquisitions will occur. As Mr. Storro stated in his testimony, the Company's Risk Policy also provides structure for the appropriate management approval level for longer-term transactions depending on the term and time of delivery into the future.

Q. Did the Company expect that forward natural gas prices would decline as they did in the June through October 2001 time frame?

A. No. At the time the hedges were made the Company expected the price for natural gas would remain high for some time into the future. Attached as Confidential Schedule No. 21 of Exhibit No. 7 on pages 19 and 32, for April 12, 2001 and May 10, 2001 respectively, are tables showing the forward natural gas prices for different periods available at the California-Oregon border at Malin as posted by Enron Canada Corporation. NYMEX futures prices, at Henry HUB, as published in Gas Daily for April 11, 2001 and May 10, 2001 are listed in Schedule No. 29 of Exhibit No. 7, pages 1 and 2. While the NYMEX prices at the Henry HUB delivery point are different from prices at the Malin delivery point, these natural gas futures all generally point to the expectation of strong prices continuing into the future. On pages 3 and 4 of the Schedule No. 29, Department of Energy – Energy Information Administration Short-Term Outlook as of April 2001 and May 2001 respectively shows that forward natural gas wellhead prices were projected to average over $5.00/MMBTU through 2002. On pages 6 through 9 of Schedule No. 29, the Department of Energy – Energy Information Administration Short-Term Outlook in May 2001 indicated that strong forward natural gas prices were expected to continue. Gas Daily articles on pages 10 and 11 of the Schedule also indicate an expectation of strong forward natural gas prices.

Q. Did other utilities in the Pacific Northwest acquire medium-term or long-term power supplies during the energy crisis?

A. Yes. Other utilities made decisions to acquire some power for terms ranging from five to eight years. Page 1 of Schedule No. 30 of Exhibit No. 7 describes purchases made by Snohomish PUD for four purchases of 25 MW amounts each. Three contacts were for five-year terms with prices indicated as $78/MWh, $105/MWh, and $150/MWh. One contract was for an eight-year term for $105/MWh. Page 2 of the Schedule No. 30 indicates that BPA contracted to purchase 300MW for a five-year term at an average price of $52/MWh. Page 3 of the Schedule illustrates the volatility of prices in the energy markets during the energy crisis and the "cost" of waiting to sign contracts under those conditions.

Q. Were the natural gas hedge transactions between Avista Corp. and Avista Energy, conducted on April 10, 2001 and May 10, 2001, consistent with market conditions at the time of the transactions?

A. Yes. Documentation of forward market prices at the time of the hedge transactions is included in Confidential Schedule No. 21 of Exhibit No. 7. Schedule No. 27 of Exhibit No. 7 shows the Malin forward price curves on the date of each of the four hedge transactions. This documentation shows that the hedge transactions with Avista Energy were consistent with market conditions at the time.

It is important to point out that there are a few factors, however, that will cause the forward natural gas price curves to be different from actual prices one is able to obtain in the market. First, the price curves for Malin are based on standard natural gas delivery periods and therefore do no reflect the fact that the NYMEX-Malin basis differential for periods that do not begin and end coincident with those standard delivery periods will actually have different pricing in the market. The two hedge transactions with Avista Energy were for the delivery period June 2002 through October 2003 which is a subset of the standard delivery period typically traded in the market of April through October. Also, the Malin price curve data will differ from actual prices in a transaction because both the NYMEX price and the basis differential between NYMEX and Malin can be volatile and move substantially as trading occurs during a day. The Malin price curves, therefore, only provide a snapshot of the price at the end of the regular trading day.

Q. What documentation does the Company currently use to record key factors relevant to its decisions to sell or buy natural gas or electric power associated with planning to serve its forward system obligations?

A. The Company maintains a number of documents that record relevant factors considered at the time of a transaction. Documentation has been, and will continue to be, enhanced over time. The following is a list of current documents that are maintained:

<u>Gas/Electric Transaction Record:</u> These documents record the key details of the price, term and conditions of a transaction and include a discussion of market conditions at the time of the transaction, the reason for the transaction, and pertinent transmission or other delivery issues.

<u>Position Reports:</u> These daily reports provide a summary of monthly loads and resources over an 18-month forward period. Also included are forward hydroelectric generation estimates as well as critical water generation variability. Fixed price natural gas quantities are also shown assigned to the most economic available generation plant.

<u>Long-Term Physical Electric Load & Resource Tabulation:</u> For transactions with deliveries extending greater than the 18-month period covered by the Position Report, the Company includes this document to show the monthly net system position during the extended period. This document also shows variability associated with an 80% confidence interval around the combined variability of hydroelectric generation and variability of load.

<u>Forward Market Electric and Natural Gas Price Curves:</u> This daily data is maintained in Nucleus, the Company's electronic energy transaction database record system.

Electric/Gas – Heat Rate Transaction Worksheet: For each natural gas transaction a worksheet is prepared which summarizes the economics of the transaction using the forward electric and natural gas prices available in the market at the time of the transaction, the most economic available marginal generator, and the resultant cost to generate electric power.

Price Quote Worksheet: Provides a record of the natural gas purchase or sales prices available from several parties in the market at the time of a particular gas transaction. This record includes price information at specific points of delivery.

Credit Report: Lists those counter-parties with which the Company is allowed to enter into either purchase or sales transactions as determined by credit criteria set by the Company. This report may also provide information on other parties' credit limits placed upon their own transactions with the Company.

In addition, from time to time, special analysis may be performed around a specific decision.

Q. What documentation has been provided for the four natural gas hedge transactions executed in April-May 2001?

A. The following documentation is provided:

- The Gas/Electric Transaction Record is contained in Confidential Schedule No. 21 of Exhibit No. 7.
- The Position Reports 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 at the time 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. These records are essentially a different form of the information contained in the Electric/Gas-Heat Rate Transaction Worksheet.
- Third party natural gas forward price data is attached to the Gas/Electric Transaction Records.

Q. What Commission prudence standards apply to the natural gas hedge transactions labeled as Deal A and Deal B?

A. We believe the prudence standards applicable to the Deal A and Deal B hedge transactions are the same as cited earlier in my testimony. The Commission has been clear in prior orders that the determination of prudence is based on the information available at the time the decisions were made. The costs related to some transactions, when viewed with hindsight (after-the-fact), may appear to be unfavorable to the Company and its customers, while other transactions would be favorable. An after-the-fact analysis, however, is not appropriate in the determination of prudence.

IV. 2001 Boulder Park – Resource Addition

Q. Please explain the acquisition of small generation resources by the Company.

A. During the year 2001, the Company took a number of different steps to mitigate the increased costs to the Company from the record low hydroelectric generation conditions and the high and volatile wholesale market prices. Schedule No. 32 outlines the many mitigating measures taken by the Company as it worked to keep costs lower in a high priced and volatile electric power market. The installation of small generation projects distributed on Avista's electric grid was just one component of the portfolio of resources that the Company chose to cover load requirements, including load variations, unscheduled generation outages, variability in hydroelectric generation, etc., and to mitigate costs. The Company selected 86 MW of small generation projects that could be installed relatively quickly, would include the necessary pollution control equipment, and could operate using natural gas, diesel fuel, or a combination of those fuel types. Of those generating projects, two utilized leased equipment and were located at the Devil's Gap substation (20 diesel units - 20MW) and the Kettle Falls (6 natural gas/diesel units - 10MW) generating station sites. The 25MW Boulder Park natural gas-fired reciprocating engine generation project was selected as a Company-owned project.

Q. Please explain why the new small generation resources were necessary.

A. Starting in the first quarter of 2001 the Company began to experience the worst year for hydroelectric generation in 74 years of recorded history. In February 2001, as the Company was evaluating alternatives to purchasing high-priced replacement energy to cover the reductions in its hydroelectric generation, it began to consider the alternative of small generation projects that might be third-party owned, Company owned, or leased.

Small generation was considered as one component of a portfolio of resource options to fill the Company's supply deficiencies because the units could be brought on-line relatively quickly, were dispatchable, had a fixed and variable component to their cost structure, and were lower cost than the forward energy market. Other utilities throughout the northwest were putting small generation projects in place to avoid purchasing power at high prices, to cover lower hydroelectric generation conditions, and to meet load obligations reliably under a variety of conditions. In the July publication of "NWPPC News", the Power Planning Council indicated that there were approximately 68 temporary generation projects that were either operating or planned. Clark Public Utilities installed natural gas-fired reciprocating engine generators. Tacoma Power installed diesel fueled generators that produced 50 MW of energy.

Q. Please explain why the Company chose the Boulder Park project.

A. The 25MW Boulder Park project was shown to be cost-effective on a total cost basis when compared to market purchases at the time of the decision to proceed in April 2001. The project was expected to have an approximate heat rate of 9,000 BTU/kWh, which is similar to that of an efficient simple cycle combustion turbines. Additionally, the six 4.1 MW units at Boulder Park provided more diversity compared to a single 9,000 BTU/kWh simple cycle generation unit, which is typically in excess of 40MW in size. Also, the reciprocating engines were capable of operation on lower pressure natural gas lines allowing for siting flexibility compared to simple cycle combustion turbines, which require high pressure gas delivery such as is available from interstate natural gas transmission lines. Boulder Park also is capable of ten-minute quick start capability and, therefore, can be used for standby reserve capacity. The long-term economic evaluation, Transaction Record, and Position Report for the Boulder Park project are attached as Confidential Schedule No. 33 of Exhibit No. 8.

Boulder Park, along with other small generation projects, provided the additional benefit of dispatchability. Boulder Park had a fixed and variable cost component. If market conditions were such that purchasing energy was a lower cost option compared to the variable cost of operating the units, the Company could save costs and choose not to run the units. Because of the fixed and variable cost components of these projects, they are similar to purchasing a "call option." A call option is essentially like buying insurance in that one pays a premium for the right to receive a benefit in the future under certain conditions. In this case, that condition is the Company's right to buy energy at the variable cost of the generation when the market price for energy is higher than that variable cost.

Q. Please explain how the Company evaluated resource dispatchability.

A. The analysis for Boulder Park was performed first using a monthly dispatch model to calculate generation output, variable costs, and economic benefit as compared to the market, and then an economic model to evaluate the overall cost-effectiveness. The generation project was dispatched against the alternative of purchasing in the forward power market. Model inputs included forward price projections for heavy load hour and light load hour electric power and natural gas fuel. The monthly dispatch of the units was performed over the expected useful life of the generation units and yielded annual values for generated energy, O&M costs, fuel costs, and margin as compared to purchasing energy from the market. These annual values were then inputs into an economic model that included the fixed and variable costs of the units over their expected useful lives.

Q. Please explain how other proposals were considered as part of the small generation resource selection process.

A. The Company researched and considered over twenty proposals from vendors. A listing of rejected projects is attached as Confidential Schedule No. 34 of Exhibit No. 8. Many vendors did not have enough information for a complete evaluation. In particular, manufacturers' information on controlled emissions was often difficult to get. The Company had a limited number of sites suitable for such generation where adequate electric transmission was available and, where required, natural gas at adequate volume and pressure was available. The vendors' ability to submit timely data on controlled emissions for air emissions modeling purposes was a critical path factor. The Company made a decision not to proceed with any vendor equipment that did not pass an air emissions modeling test for a specific site. In addition to owned or leased projects, the Company also received proposals from customers and third parties that were installing co-generation. Four projects totaling 10.6 MW reached the point where the Company offered pricing and contracts. Only one developer executed a contract with the Company for 3 MW. The contract provided for a flexible hourly pricing structure: \$60/MWh fixed price plus a variable price component based on 50% of the difference between the daily, heavy load hour or light load hour, non-firm Mid-Columbia market index less \$60/MWh. The fixed/variable pricing structure added another element to the Company's resource portfolio mix. However, the energy market prices fell before any power was generated, and it was not economic to run the project.

Q. Please explain how build options were considered as part of the small generation selection decision.

A. The Company-owned or leased small generation projects were all build options and their economics were compared to the alternative of purchasing energy in the high priced forward market. Over 20 proposals were considered from various vendors.

Q. Was the Boulder Park project re-evaluated as power market conditions changed?

A. Yes. On June 19, 2001 a review of the Boulder Park project was conducted, along with the five originally selected small generation projects. New dispatch models and economic models were run for the Boulder Park and other generation projects that were long-term purchases of equipment. Attached as pages 1 and 2 of Confidential Schedule No. 35 of Exhibit No. 8 are tables summarizing the results of the updated modeling performed on June 11, 2001. Also included in the table on page 1 are summaries of the original economic analyses, at the time projects were selected, as well as an analysis on June 4, 2001.

Two types of analysis were performed. First, each project was reviewed using updated monthly dispatch and economic modeling for long-term projects and simple economic analysis for leased projects as previously described. Second, the call option premium value, representing the value of the generation in the market at the strike price of its variable cost of operation, was calculated for each project. The call option premium for a one-year period was calculated using a Black-Scholes mathematical options model. The call option premium was compared to the cost to complete the project, which either yielded a net benefit or cost, as shown on page 2 of Confidential Schedule No. 35. The valuation of these projects against a call option value was a valid additional economic comparison because the peaking nature of these units is tied more to their capacity value than to the energy value. The objective of the call option valuation was to reflect the value of the capacity of generating units that may not run as frequently in the market at the strike price of the various units variable cost of operation. The Company only evaluated the call option premium for a single year. There would be additional premium values for subsequent years.

The dispatch and economic analyses showed that the Boulder Park project did not show positive economics at the June 11, 2001 analysis date due to the change in the projected forward price for electric power. However, the net benefit of the project as compared to the value of a one-year call option premium showed that Boulder Park was economic compared to the market.

The Boulder Park project was determined to be economic because the cost to complete Boulder Park was estimated to be approximately equal to the premium for the one-year call option. Therefore, that project was continued. Additionally, prices in heavy load hours, in many forward months, were still at levels at or above the estimated $50/MWh marginal cost of operating the project. On June 19, 2001, forward market prices for heavy load hours were as follows:

Period	Market Price -HLH
July 2001	$116/MWh
August 2001	$129/MWh
September 2001	$108/MWh
Q4 – 2001	$103/MWh
Q1 – 2002	$85/MWh
Q3 - 2002	$90/MWh

Q. What was the total actual cost of construction for the Boulder Park project?

A. The total cost to construct the Boulder Park project was approximately $31.9 million, including associated transmission and substation cost. This compares to the projected cost to construct the project of $21 million estimated at the time of the May 18, 2001 economic evaluation and $23.7 million estimated at the time of the June 11, 2001 economic evaluation. Contractor costs were approximately $4.7 million over budget due to such factors as the additional design scope, change orders, overall project complexity not reflected in original estimates, and project management costs due to extra time required to complete the project. Avista construction costs were over budget by approximately $2.2 million due to changes in project scope and complexity.

Given the circumstances, project costs were reasonably managed by the Company. The excess costs 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. Avista took over from the project management firm the final engineering and commissioning for Boulder Park in order to save further costs.

V. <u>2001 Kettle Falls CT – Resource Addition</u>

Q. Please explain the addition of the new combustion turbine (CT) at the Kettle Falls plant site.

A. Company engineers, in early 2001, considered and evaluated some options for adding generation capacity at the Kettle Falls plant. The option selected was the addition of a small 6.5 MW natural gas simple cycle combustion turbine coupled with a heat recovery boiler with the steam sent to provide heat to the feed-water heater for the existing Kettle Falls wood waste fueled generator. The additional heat that is provided to the wood waste project feed-water heater increases the generation capability of the existing plant by approximately 2 MW. The utilization of the waste heat from the simple cycle turbine essentially allows the energy produced by the natural gas fuel to be used twice.

Q. Please explain why the installation of the new 6.5 MW CT with heat recovery at Kettle Falls generating station was reasonable?

A. On February 14, 2001, an economic analysis was performed on three alternative configurations for adding a small generator at the Kettle Falls generating station. Compared to purchasing power in the market, the 6.5 MW simple cycle generator combined with steam heat recovery for provision of heat to the feedwater heater of the woodwaste fueled generator yielded a net present value of approximately $10.6 million over the 25-year life of the project. The net nominal levelized benefit was calculated to be $16.10/MWh. The economic analysis is included in Schedule No. 36 of Exhibit No. 9. An hourly dispatch model was used to determine the annual generation, variable costs and fuel costs to operate the generator. The Prosym™ dispatch model outputs were used as inputs to the economic model producing the results stated above. The results indicated that this project was a better alternative than purchasing from the power market.

Q. Was the project re-evaluated as power market conditions changed?

A. Yes. In September 2001, the Company reviewed the marginal cost economics of completing the project. The hourly dispatch model and economic model were re-run using updated forward prices. The economic analysis ranged from a negative net present value of $856,000 in simple cycle operation to a positive $4 million for combined cycle operation over 24 years compared to purchasing energy in the market. The Company expected that the project would operated approximately fifty percent of the time in combined cycle operation, based on hourly dispatch models which took into account the price of wood fuel and the price of natural gas. Analysis indicated a positive net present value of $700,000 under the expected operating conditions. Pages 6 through 11 of Confidential Schedule No. 36 show the re-evaluation and the economic analysis of the marginal cost of completing the project.

Q. Does that conclude your pre-filed direct testimony?

A. Yes it does.