BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

DIRECT TESTIMONY OF ROBERT J. LAFFERTY

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Robert J. Lafferty, I am employed as Manager, Wholesale Power for Avista Corporation and my business address is 1411 East Mission Avenue, Spokane, Washington.

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 a various positions in the energy resources area (electricity and natural gas) involving the planning, acquisition and optimization of energy resources. Since January 2001, I have served as Manager, Wholesale Power 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 several resource acquisitions made by the Company in 2000 and 2001. In my testimony I will provide an overview of Avista's resource planning and power operations. 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 the Coyote Springs II (CSII) for the Company's supply-side resource portfolio and the selection of demand-side projects for negotiation. I will cover the prudence of medium-term forward natural gas purchases for combustion turbines and hedging of those purchases to fix a portion of the price. I will explain the prudence of the acquisition of small generation, acquisition of new emission controls equipment for the Northeast Combustion Turbine and the addition of a small combustion turbine to the existing Kettle Falls generation project. I will explain the re-evaluation of the CSII project and the reasonableness and prudence of the Company decision to sell 50% of the project. Finally, I will explain the non-fuel operating costs for the new CSII, Boulder Park, and the Kettle Falls CT generating projects.

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

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

Exhibit #	*Description*
RJL-1	Resource Planning & Operations
RJL-2	2000 Resource Selection Process Report
RJL-3	1997 IRP Update (filed in July 2000)
RJL-4	Evaluation Process Flow Chart and Evaluation Guidance for RFP
RJL-C5	Resource Selection Process – 2nd Round Screening
RJL-6	2000 Request For Proposals
RJL-7	RW Beck – RFP Bid Analyis Review
RJL-C8	Resource Seletion Process – 3rd Round Screening
RJL-C9	Resource Planning & Acquisition Documentation Index
RJL-C10	Revenue Requirement Analysis – Top Projects
RJL-11	12-Month Rolling – Forward Electric-Gas Implied Heat Rate Spread
RJL-12	Forward Natural Gas Purchases – Apr. 2000 through Oct. 2001
RJL-13	Natural Gas Requirements for Avista Generation
RJL-C14	Natural Gas Transaction Records for Medium-Term Purchases
RJL-15	Natural Gas Forward Price Information – April/May 2001
RJL-16	Natural Gas Hedging – Article
RJL-17	High Electric Prices – Dec. 2000 – Articles
RJL-18	Monthly Load Variability Chart
RJL-C19	Small Generation Projects – Initial Economic Analysis
RJL-C20	Small Generation Projects – Rejected Projects
RJL-C21	Small Generation Projects – Re-evaluation
RJL-22	NECT – Pollution Control Equipment Installation – Economic Evaluation
RJL-23	Kettle Falls CT – Initial Economic Evaluation and Re-evaluation
RJL-C24	Coyote Springs II – Re-evalation
RJL-25	Coyote Springs II & Boulder Park – Non-Fuel Operating Costs

II. AVISTA'S RESOURCE PLANNING AND POWER OPERATIONS

Q. Would you please provide a brief overview of Avista's resource planning and power supply operations?

A. Yes. The Company uses a combination of both owned and contracted resources to serve its retail and wholesale load requirements. Dispatch decisions related to these resources are made within the Energy Resources Department of Avista Utilities. The Department conducts studies on a regular basis to determine the need for capacity and energy resources on a short-term, medium-term and long-term basis. The Company enters into short-term and medium-term wholesale sales and purchases transactions to balance its resources with load requirements. Longer-term resource decisions related to building new resources, upgrades to existing resources, demand-side management (DSM) and long-term contract purchases are generally made in conjunction with the Company's Integrated Resource Plan (IRP) and RFP processes. The Company, however, also acquires resources outside of an RFP process. Exhibit No. __ (RJL-1) provides additional details related to Avista's resource planning and power operations, as well as a tabulation of its loads and resources for the next ten years.

Q. Has the load forecast included in Exhibit No. __ (RJL-1) been updated as compared to that recently filed in Docket No. UE-010395?

A. Yes. Avista prepared a new load forecast in summer of 2001 for the years 2002-2011. Load projections include expected price elasticity in response to increased retail electric rates. Also included in the projections are the effects on power usage resulting from a slowing economy in Avista's electric service territory through late 2002. Also included is the Potlatch retail load of 93 aMW. The Company expects to sign an agreement with Potlatch for retail electric service to its Lewiston, Idaho plant by the end of 2001, or soon thereafter.

Q. Has the Company's forecast of available resources been updated as compared to that recently filed in Docket No. UE-010395?

A. Yes. There are several notable changes to the Company's load and resource tabulation. The Company expects to complete a sale of 50% of the CSII project to Mirant by the end of 2001. The power output that the Company will receive from the CSII project has been adjusted to 50% of the total plant output. The Company and Potlatch have not signed a new contract for Avista's continued purchase of Potlatch's generation output, therefore that generation has been removed from the resource tabulation beginning in 2002. Potlatch may choose to self-generate into their own facility load or they may choose to sell into the market. The Boulder Park 25 MW project, consisting of six 4.1 MW natural gas reciprocating engines has been added to the Company's portfolio. Two additional and identical units are planned for installation at the Boulder Park site conditional on emission testing of the first six units. These two units, totaling approximately 8 MW, will be included in the Company's load and resource tabulation when the emission tests indicate that they can be sited at the Boulder Park location. The Company's new forecast shows peaking turbine annual energy output based on the amount those units would operate on a monthly basis to serve load in a critical water year.

Q. Please summarize the future net load and resource position for the Company.

A. The Company remains in a nearly balanced energy position for 2002 and 2003. The Company's capacity position is near balanced in 2002 and is surplus in 2003 with the addition of CSII. The Company's net resource position becomes deficient beginning in 2004 and going forward from that point in time. The average energy resource deficiency is 131 aMW in 2004 and increases to 355 aMW in 2011. The capacity deficiency is 108 MW in 2004 and increases to 613 MW in 2011.

Q. How will the Company plan to meet the future needs for resources beginning in 2004?

A. The Company will continue to evaluate options for filling the net resource requirement gap as 2004 approaches. The Company would expect to evaluate a mix of options including medium-term market purchases in heavy load hour and light load hour time-blocks, long-term market purchases, build options, renewable resource options, demand-side resource options, and generation lease options or tolling[1] options. As stated earlier, longer-term resource decisions related to building new resources, upgrades to existing resources, demand-side management (DSM) and long-term contract purchases are generally made in conjunction with the Company's IRP and RFP processes. The Company, however, is not precluded from acquiring resources outside of an RFP process.

III. 2000 Resource Selection Process – Overview/Summary

Q. Please provide an overview of the resource selection process that was concluded in the year 2000, through which the CSII project and some demand-side resources were selected.

A. That resource selection process is summarized in the "2000 Resource Selection Process Report" which is attached as Exhibit No. __ (RJL-2). 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 Exhibit. 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;

[1] "Tolling" is an energy conversion service whereby a provider takes customer supplied natural gas and converts it to an amount of electric energy which is delivered to the customer as determined by a defined conversion ratio. The conversion ratio is can be tied to the heat rate and variable operating costs of a generating plant. The fixed cost of the plant can be covered in fixed fees charged by the tolling service provider. Tolling service may be contingent on the operation of a specific generation plant.

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 WUTC; 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 Commission's general request for comments;

7) Approval of the 2000 RFP by the WUTC;

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 and reviewed with Commission Staff;

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

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; CSII 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 as one of the screens;

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

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

Q. What plans did the Company put in place to replace the energy generated from the Centralia thermal project?

A. The plan to replace 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. The term of the purchase was from the time of the plant sale 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's expects to receive 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 Docket No. UE-991606, and the Commission approved the ratemaking treatment for this contract.

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 CSII as a supply-side resource and three demand-side proposals for negotiation.

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

A. In 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 project was the preferred site for a combined cycle combustion turbine project. The site study provided a basis for Avista to later develop preliminary engineering analysis necessary to determine costs for a Company-build option to compare to third-party proposals in the planned RFP process.

Q. Describe 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. In addition, using the Prosym hourly dispatch model, the Company assessed the magnitude and duration of the net resource deficiency facing the Company under the 60 years of hydroelectric generation conditions using hourly data. The duration of the resource deficiency indicated that a base-load resource was needed by year 2004. 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 in July 2000 with the 2000 IRP are included in pages 71 through 83 of Exhibit No. __ (RJL-3).

Q. Please give an overview of the evaluation process used for supply-side resource bids and for Company-build option projects.

A. Supply-side and demand-side resources were both subjected to a multi-step evaluation and screening process laid out in advance of the opening of 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 Exhibit No. __ (RJL-4), pages 2-6. 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, economic modeling was 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 a 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. 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 attached as Exhibit No. __ (RJL-4), page 1. 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 summary is attached as Confidential Exhibit No. __ (RJL-C5)

Q. What build options were included in the comparison of 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 CSII 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 at cost from affiliates, in order to be considered for purchase". The RFP is attached as Exhibit No. __ (RJL-6).

Q. Did the Company have any independent review of its analyses of supply-side resource dispatch and economic analysis performed?

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 Exhibit No. __ (RJL-7). RW Beck makes the following assessment of the Company's analytic approach and methodology on page 7 of the Exhibit.

> "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 CSII project near Boardman, Oregon as the preferred supply-side option. Besides overall cost effectiveness, a key factor in selecting the CSII project was that it included a fully licensed site. The major equipment had already been ordered and an Engineering Procurement Contractor had already been selected for the project. These factors combined to make some major cost and timeline factors more well 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 Exhibit No. __ (RJL-C8)

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 Exhibit No. __ (RJL-C9).

Q. Please give an overview of the evaluation process used for demand-side resource bids.

A. Proposals involving acquisition of resources on the customer side of the meter, whether energy-efficiency or customer-owned generation, were initially screened for compliance with minimum RFP requirements. Proposals that were deemed to not meet minimum requirements were given an option to correct deficiencies. One proposal failed to correct these deficiencies. The remaining seven proposals were advanced to the evaluation stage.

A six-person team was created to perform evaluation on each of the remaining seven proposals. Two individuals were common to evaluation of the both supply-side and the demand-side proposals. The evaluation teams reviewed and scored each proposal. All evaluation team members collectively performed a ranking and short-listing of the proposals. Three proposals were short-listed and proceeded to negotiations. Avista reached an agreement on final contract language for two to of the proposals.

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

A. The Company has reached agreement on two demand-side proposals representing 3 MW in energy savings acquired over a three year period. The Company has extensive documentation of the evaluation and selection of the demand-side RFP proposals available at the Company's offices.

IV. Prudence Criteria Previously Adopted By Commission

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 Eleventh Supplemental Order in Docket No. UE-920433, dated September 21, 1993, and its Nineteenth Supplemental Order in the same Docket, dated September 27, 1994. The Orders state as follows:

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

The test this Commission applies to measure prudence is what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. (Page 20)

A demonstration of prudence of resource acquisition includes showing both that the selection of the resource was necessary and reasonable and that the costs of acquisition were appropriate. (Page 20)

The Commission's acceptance of a Company's least-cost plan does not represent a finding of prudence of a particular resource. Furthermore, the least-cost planning process is not sufficiently rigorous or specific to support an independent finding of prudence. (Page 21)

Avoided cost is just one more factor which may be considered in determining prudence. However, cost values must be adjusted for items such as load factor and seasonality in order to make a reasonable evaluation of the prudence of the acquisition. (Page 21)

Although the competitive bidding rule (WAC 480-107-060) provides that information gathered in a competitive bid may be used for analysis in a general rate case, the prices submitted pursuant to the bid may be used only for a general, qualified comparison with the acquired resource as another component of the prudence review. (Page 21)

The Commission sees no reason to deviate from the traditional prudence standard recited above, and we concur with Commission Staff that the review should include at a minimum dispatchability, transmission impacts, other bids, building options, and financial and rate impacts. (Page 22)

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

The Commission relies upon a reasonableness standard. The company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made. (Page 10)

The prudence standard adopted in prior Commission orders is easily applied to any resource decision, whether it is to build or to purchase. The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering purchase of a resource, it must evaluate that resource against the standards of what other

> purchases are available, and against the standard of what it would cost to build the resource itself. Specific factors which must be included in its analysis are included in the Public Utility Regulatory Policies Act of 1978 (PURPA), and in Commission rules. Other factors will be identified in the company's least cost plan. The factors identified in the National Energy Policy Act of 1992 will need to be considered in purchases made after its adoption. (Page 11)

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 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.

The Company has provided extensive documentation in this filing, through testimony, exhibits and work papers, 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 <u>reasonable choice</u>. Furthermore, it is important to recognize that in many cases, there is a range of reasonable choices that a Company can make.

V. 2000 Resource Selection Process

Q. What minimum prudence criteria was laid out by the Commission in Docket No. UE-920433 with regard to the selection of new power resources?

A. The following is a list of minimum criteria laid out in Docket No. UE-920433:

1) Determine whether a new resource is necessary;

2) Determine how to fill the resource in a cost-effective manner including available purchases compared against the standard of what it would cost to self-build the resource;

3) Resource dispatchability;

4) Transmission impacts;

5) Other bids;

6) Building options;

7) Financial rate impacts;

8) A range of views about an uncertain future is more valuable than a single one.

Q. Please explain how the Company demonstrated that a new resource was necessary?

A. The Company updated its 1997 Integrated Resource Plan in spring of 2000 (1997 IRP Update, or as referred to in this testimony, 2000 IRP) and reviewed that plan with the IRP Technical Advisory Committee. The 2000 IRP showed a need for 300 MW of capacity and energy beginning in 2004. The Company subsequently filed the 2000 IRP with the Commission on July 13, 2000. The loads and resources contained in the plan showed an obvious need for power beginning in 2004.

Q. Please explain how the Company demonstrated that the resources selected filled the resource need in a cost-effective manner including available purchases compared against the standard of what it would cost to self-build the resource?

A. The Company compared the variety of resource bid proposals, including market purchases, tolling proposals and turnkey power generation project proposals, received in the 2000 RFP with one another and against Company-build options. A consistent evaluation process was used to evaluate the dispatch value and costs of each resource option over a 25-year period in conjunction with the Company's existing resources. The Company rated each project across a consistent set of price and non-price factors to come up with a weighted matrix evaluation and ranking for each resource proposal. Factors included in the weighted matrix evaluation were: economic benefit of the resource (35%); long-term financial performance capability of the bidder (15%); fuel price risk (15%); fuel availability risk (5%); electric factors such as dispatchability, ramping, reactive capability, transmission contingency exposure, etc. (20%); and environmental factors including permits, plan for compliance with applicable regulations, and proven technology (10%). The Evaluation Guidance attached as Exhibit No. __(RJL-4) provides further detailed explanation of the resource evaluation process. The 2000 Resource Selection Process Report, on page 7 of Exhibit No. __ (RJL-2), explains the development of the weighted matrix evaluation. This evaluation matrix and the write-up describing the various weightings and the ranking process were reviewed with Commission Staff members on September 13, 2000, prior to opening of the RFP bid proposals.

Q. Please explain how the Company evaluated resource dispatchability?

A. The Company used Prosym as the tool to perform an hourly dispatch evaluation of the resource options considered for selection under the resource selection process. This dispatch model showed how each resource alternative would operate in conjunction with Avista's existing resources under different hydroelectric generation conditions and different electric and natural gas price scenarios. The model calculated the energy generated by the proposed power supply option and the differential variable system costs for each of the different resource options compared to a base case which used market purchases to meet resource deficits. The variable costs of operation and the energy generated by the resource were the inputs into the economic modeling step.

Q. Please explain how the Company evaluated the transmission impacts of resource alternatives?

A. Incremental electric transmission costs were included in the economic modeling step for resource alternatives. In addition, transmission considerations, such as exposure to transmission contingencies, were included in the non-price "electric factors" ranking in the weighted Evaluation Matrix.

Q. Please explain how other bids were considered as part of the resource selection?

A. The Company evaluated 32 third-party supply-side and demand-side proposals submitted through the 2000 RFP process. Supply-side resources were compared to one another in a weighted Evaluation Matrix that considered both price and non-price factors. Demand-side resource options were compared against any mutually exclusive DSM opportunities, both internal and external. Demand-side resource options were also measured against the avoided costs of supply-side options.

Q. Please explain how build options were considered as part of the resource selection?

A. The Company investigated over thirty sites for a potential combined cycle combustion turbine. Site options were screened to five sites by a cross-department team of

Avista employees. An outside engineering firm was hired to prepare a detailed site analysis on those sites. The Company obtained third-party budgetary costs for a generation project at Rathdrum. The Company-build options were evaluated using the same modeling and evaluation process as bid options under the 2000 RFP.

Q. Please explain how financial rate impacts were considered in the evaluation?

A. The Company performed twenty-five year economic benefit analyses based on the variable O&M costs, fuel costs, portfolio operational costs delta (benefit as compared to a base case without the resource), fixed costs and generation output which are the results of the Prosym dispatch model output for the particular resource. This analysis was performed for the base case electric and natural gas price forecasts as well as each of the three pricing scenarios. The financial analyses of these scenarios were reflected in the comparative price ranking of different resource options. Base case and pricing scenario analyses results are presented in attached Confidential Exhibit No. __ (RJL-C8). The Company also performed a projection of revenue requirements for the top three projects in the evaluation process. The CSII and Rathdrum build projects were deemed equivalent on a 25-year levelized basis. A flat energy market option was approximately $2.8 million less in value on a 25-year levelized basis for the base case. The revenue requirements analysis is attached as Confidential Exhibit No. __ (RJL-C10)

Q. How has the Company incorporated a range of views about an uncertain future in its comparison of resources?

A. The Company performed hourly Prosym dispatch modeling analysis using electric and natural gas pricing scenarios for high natural gas prices, low natural gas prices and high northwest region demand for the short listed projects. The financial analyses of these scenarios were reflected in the comparative price ranking of different resource options.

Q What other factors have been incorporated by the Company in its evaluation of resource alternatives?

A. In the third screening analysis, the Company included a salvage value for physical resource projects at the end of their projected life. This value, though small, represents the end-effects of the physical project. Also included in the modeling of physical generation projects were maintenance cycles, random outages, start costs, minimum up-times, and minimum down-times.

V. 2001 Natural Gas Purchases

Q. Please describe the Company's buying strategy for its natural gas combustion turbines.

A. As part of optimizing the use of its natural gas combustion turbines, the Company may choose to secure fixed price gas supply in forward months depending on the spread ("implied heat rate[2]") between the price of natural gas and the price of electric power in those forward months. We will look at two examples, and for simplicity we will ignore non-fuel variable costs of operating the Rathdrum turbine.

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 $200/MWh and natural gas price is $5.00/MMBTU, this represents a implied heat rate of

[2] "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).

40,000BTU/kWh. The implied heat rate is well above the 12,000 BTU/kWh heat rate. Therefore, in this example, Company is better to purchase gas at \$5.00/MMBTU for the Rathdrum combustion turbine at the 12,000 BTU/kWh heat rate, and to generate electricity at \$60.00/kWh, compared to purchasing power in the market for \$200/MWh.

2) If the forward price for power is \$30/MWh and the price for natural gas for the same period is \$3.10/MMBTU, this represents a implied heat rate of 9,677 BTU/kWh. This implied heat rate is below the 12,000 BTU/kWh heat rate of the Rathdrum combustion turbine. Therefore, it is more economic to purchase electric power for \$30/MWh than to purchase natural gas for the Rathdrum turbine. The cost to generate electric would be \$37.20/MWh at a natural gas price of \$3.10/MMBTU.

Prior to year 2000, the forward implied heat rate between electric power price and natural gas price was not often high enough to warrant purchasing natural gas for future electric power generation given the 12,000 BTU/kWh heat rate of the Rathdrum plant. To the extent that 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 natural gas and electric price spread for that day.

For the period February 2000 through April 2000, the implied heat rate between 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 this latter period implied heat rate is substantially greater than the 12,000 BTU/kWh, the Company acquired some forward natural gas for fueling Rathdrum, Northeast, Boulder Park and Coyote Springs generation projects in place of purchasing more expensive power in the electric wholesale market. Exhibit No.__(RJL-11) shows a graph illustrating how the rolling 12-month calculated implied heat rate between natural gas and electric forward price has changed over the period from January 25, 2000 through November 12, 2001.

A table of all of the Company's forward purchases of natural gas for its natural gas fired generators for the period April 2000 through October 2001 is attached as Exhibit No. __(RJL-12). In April 2000, the Company began purchasing 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 energy from the market to cover resource deficiencies. 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 CSII 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 CSII affected the Company's acquisition of natural gas for generation?

A. CSII 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 Exhibit No. __(RJL-12), the variable generation cost for CSII was significantly below the forward price for electric power for the same period.

The annual average maximum daily natural gas portfolio requirement needed to cover the total natural gas fired generation operated by the Company increased 73%, from approximately 58,700 dekatherms per day (Dth/day) to approximately 101,500 Dth/day, with the addition of CSII. Page 1 of Exhibit No. __(RJL-13) is a graph showing the average maximum daily natural gas consumption by generation project for a one year period. The annual maximum average daily natural gas requirements for the natural gas fired generation plants operated by the Company is tabulated on page 2 of Exhibit No. __(RJL-13).

In addition, financial institutions that were considering providing the long-term financing needed for the CSII project required that the Company secure firm delivered fuel for the project prior to financing.

Q What steps did the Company take to secure firm natural gas transportation and firm natural gas supply for its supply portfolio?

A. The Company took a series of steps in the first half of 2001 to secure the firm natural gas supply for CSII, secure long-term natural gas transportation for CSII, and to fix a portion of the Company's forward natural gas supply costs.

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 2001. PG&E GTN indicated that while there was no currently unsubscribed, firm, year-around transportation capacity available, that they were planning to conduct a limited open season offering of firm transportation capacity in first quarter 2001, and depending on response, they might later conduct an unlimited open season offering following.

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 ten times 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 48,000 Dth/day at a floating monthly index-based price plus an adder. This represents 47% of the Company's natural gas portfolio and enough firm natural gas supply to operate the CSII plant including the duct burner. The

natural gas can 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 gives flexibility in the use of the gas. The term of one transaction for 28,000 Dth/day is November 1, 2001 through October 31, 2004. The term of the second transaction for 20,000 Dth/day is June 1, 2002 through October 31, 2003. During the period November 1, 2001 through May 31, 2002, gas supplies are available for use either at peaking projects, such as the Rathdrum, Northeast CT or the Boulder Park projects, or for use as CSII test gas. Once CSII begins 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.

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 CSII. The capacity is planned to be available beginning November 1, 2003.

5) The Company will utilize 15,000 Dth/day of firm transportation capacity on PG&E GTN. 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.

6) In April and May 2001, the Company hedged, or fixed the price, of 40,000 Dth/day for varying future periods, representing up to 39% of the Company's annual natural gas portfolio and 83% of the gas purchased at index-based prices. The hedge was performed through four fixed-for-floating transactions. The weighted average hedge prices, including index adder, were: $5.99/Dth for 20,000 Dth/day for the June 1, 2002 through October 31, 2003 period; and $6.45/Dth for 20,000 Dth/day the November 1, 2001 through October 31, 2004 period. Each of the four hedges are listed in the Summary of Forward Natural Gas Fixed Price Purchases, in Exhibit No. __(RJL-12). In that exhibit, the calculated variable cost of generation, resulting from using the natural gas in generation units with different heat rates, is compared to the forward electric power prices available in the same forward period. In each case, hedging the price of natural gas was less expensive than purchasing power at prices available in the forward market.

The April-May 2001 hedges fixed the price of 44% of natural gas for Rathdrum for the 2-month period November 1, 2001 through December 31, 2001. The hedges fixed the price of 100% of Boulder Park and 32% of Rathdrum for the 5-

month period January 1, 2002 through May 31, 2002. During these two periods, the hedges covered 20% of the Company's natural gas portfolio.

The April-May 2001 hedges fixed the price of 93% of the natural gas for CSII for the 17-month period June 1, 2001 through October 31, 2003. During this period, the hedges covered 39% of the Company's natural gas portfolio. The hedges fixed the price of 47% of the natural gas for CSII for the 12-month period November 1, 2003 through October 31, 2004. During this period, the hedges covered 20% of the Company's natural gas portfolio.

Attached as Confidential Exhibit No. __(RJL-C14) 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.

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 times when the hedges were made, the Company expected that price for natural gas would remain high for some time into the future. Attached as Confidential Exhibit No. __ (RJL-C14) 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 on Exhibit No. __ (RJL-15), pages 1 and 2. These natural gas futures all point to the expectation of strong prices continuing into the future. On page 3 and 4 of the Exhibit No.__(RJL-15), 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 the Exhibit No.__(RJL-15), the

Department of Energy – Energy Information Administration Short-Term Outlook in May 2001 indicate that strong forward natural gas prices were expected to continue. Gas Daily articles on pages 10 and 11 of the Exhibit also indicate an expectation of strong forward natural gas prices.

Q. Were the index-based firm delivered natural gas purchases prudent?

A. Yes. The Company was unable to secure immediate firm natural gas supply and firm gas transportation to CSII. Therefore, it was reasonable to lock in firm delivered gas supply for CSII. CSII is planned to operate as a base load plant given its low heat rate (high efficiency). Firm delivered gas would provide supply until the time when additional firm transportation was projected to be available on PG&E GTN pipeline. The index-based price was the preferred pricing of the seller and provided flexibility to the Company with regard to hedging the price of the firm supply.

The tables below briefly summarizes the variable cost of CSII, Rathdrum, Northeast CT and Boulder Park generation compared to the forward market price available at the time of the natural gas purchases.

Coyote Springs II

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

Rathdrum

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

Northeast CT

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

Boulder Park

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

Beyond the term of those hedges, the Company may either layer in further hedges and natural gas purchases, either at fixed prices or index-based prices.

Q. Were the financial hedges to fix a portion of the index-based firm natural gas prudent?

A. Yes. It was also reasonable to financially fix a portion of the firm gas supply for Company natural gas fired generation, including CSII, with four separate transactions. The hedges allowed the Company to fix varying portions of its Rathdrum, Northeast CT, Boulder Park, and CSII natural gas fired generation cost at prices lower than the comparable electric power prices available at the time. Other companies hedge portions of their natural gas supplies to eliminate a portion of the price volatility from their portfolio. Natural gas local distribution companies in the state of Washington employ a variety of approaches. Avista hedges approximately half of its requirements twelve to eighteen months into the future. Exhibit No. __(RJL-16), indicates that Cascade Natural Gas has hedged the price of its natural supply for customers for the next three years to protect from spikes that can occur in the volatile wholesale market.

VI. 2001 Small Generation/Resource Acquisition

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

A. In Dockets No. UE-010395 and UE-011514, Company witness Norwood explained the different steps taken by the Company to mitigate the increased costs to the Company from the record low hydroelectric generation conditions and the high wholesale market prices. The installation of small generation projects distributed on Avista's electric grid is 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 quickly, would include the necessary pollution control equipment, and could operate using natural gas, diesel fuel, or a combination of those fuel types. Those projects consisted of 30 MW of leased units, that could be removed mid-year 2002 as CSII was scheduled to come on line, and 56 MW of Company-owned units. In addition, the Company completed one contract with a third party to purchase output from a 3 MW small generation project. The following table summarizes the above projects:

Site	MW Output	Type	Fuel	Dispatchable	Ownership	Status
Boulder Park	25	Reciprocating Engine	Natural Gas	Yes	Avista	Construction in progress. January 2002 on-line.
Spokane Industrial Park	8	Reciprocating Engine	Natural Gas	Yes	Avista	SIP project is cancelled. Assessing relocation of units to Boulder Park.
Kettle Falls	10	Reciprocating Engine	Bi-fuel: Natural Gas & Diesel	Yes	Leased	On-line.
Devil's Gap	20	Reciprocating Engine	Diesel	Yes	Leased	Cancelled due to decline in energy prices.
Othello	23	Combustion Turbine	Diesel	Yes	Avista	Cancelled due to decline in energy prices.
Small Butte Power	3	Reciprocating Engine	Diesel	No	Third-party	No power generated due to decline in energy prices

Subsequent to the drop in the electric power market in the second half of 2001, two of the projects (Othello and Devil's Gap), totaling 43 MW were cancelled. Another project that required property purchase (Spokane Industrial Park) was also cancelled, however the two generation units originally planned for that project are now being planned for installation at the Boulder Park site contingent upon air emission testing.

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

A. As established in Docket No. UE-010395, 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 quickly, were dispatchable, had a fixed and variable components 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.

In addition to covering its average planned load obligations, the Company also had concerns regarding the high and volatile electric power prices and the additional obligations created by variations in load, variations in hydroelectric generation, and variations created by unplanned outages of generation units. The recent events of December 2000 showed that dramatic price spikes could occur as companies and the power market anticipated the load variability of a winter cold snap. Northwest market 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 Exhibit No. __(RJL-17). Page 2 of Exhibit No. __ (RJL-17) includes an except 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 coming summer appeared to have the potential to create similar shortage-based extreme price spikes. The continued fall-off in available hydroelectric generation in the Pacific Northwest caused the same concerns for both having adequate generation to meet the Company's variable load obligations and concerns that dramatic price spikes could occur. The Company forecasts loads on an average basis for each month and plans resources to meet those requirements. However, at a 95% confidence interval, the Company's weekly loads can vary from the average by up to 105 aMW on an average basis. Exhibit No. __ (RJL-18) shows with an 80% and a 95% confidence interval how much loads have varied historically in each month of the year. If the Company were to have to purchase 100 aMW additional power for one week at a price of $1000/MWh, the cost to the Company would be $16.8 million. Exposure to variability in hydroelectric generation or unplanned outages of other resources could cause similar exposure to the risks of the high power prices and high volatility of prices in the electric power market.

Given the high power market prices and the high volatility of power prices, there was a need to plan not only to cover average load obligations, but to have some degree of coverage for load variability, hydroelectric generation variability, and unplanned outages of generation units.

Q. Please explain how the Company demonstrated that the small generation resources selected were prudent.

A. The small generation projects selected were shown to be cost-effective on a total cost basis when compared to market purchases at the time of the decisions to proceed. The five projects that were initially selected in the April/May 2001 period were Boulder Park (25 MW), Kettle Falls Bi-Fuel (10MW), Spokane Industrial Park (SIP) (8MW), Devil's Gap (20 MW) and Othello CT (23 MW). The initial economic evaluation, transaction record, and position report for the five projects initially selected are attached as Exhibit No. __ (RJL-19). The analysis performed for the Boulder Park, SIP, and Othello CT projects employed a long-term analysis approach because the Company would purchase the equipment; whereas the Kettle Falls Bi-Fuel and Devil's Gap projects were one-year lease projects and a more simple approach was used.

These generation projects also provided the additional benefit of dispatchability. The units 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 can choose to not 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 analyses for the Boulder Park, SIP (Spokane Industrial Park), and Othello CT projects were performed first using a monthly dispatch model to calculate generation output, variable costs and economic benefit compared to the market, and then an economic model to evaluate the overall cost-effectiveness. These generation units were 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, natural gas and diesel 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 benefit compared to purchasing energy from the market. These annual values were then inputs for an economic model that included the fixed and variable costs of the units over their expected useful lives.

The Kettle Falls Bi-Fuel and Devil's Gap projects were twelve-month lease projects. The year-ahead energy market prices were high and initial analysis showed these units would operate with positive total economics in almost all months of their lease. Therefore, a simple economic analysis was performed, where the units operated during each of the months at a 90% and 92% plant factor respectively, and that analysis showed positive benefits for these projects over their lease terms.

Q. Please explain how the Company evaluated the transmission impacts of resource alternatives.

A. All projects were connected directly to the Avista transmission or distribution system. No third-party transmission was required. All costs to interconnect the generation to the power grid were reflected in the economic analysis.

Q. Please explain how other bids were considered as part of the resource selection process.

A. The Company researched and considered over twenty proposals from vendors. A listing of rejected projects is in attached Exhibit No. __(RJL-20). Many vendors did not have complete information needed 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 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 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 for various vendors.

Q. Please explain how financial rate impacts were considered in the evaluation of small generation resources.

A. The economic modeling of the relative benefits to proceed with each project was compared with a purchase from the forward power market over the expected life of the equipment or over the term of the contractual agreement as was appropriate.

Q. How has the Company incorporated a range of views about an uncertain future in its comparison of resources?

A. The Company selected five small generation resources as a portion of its overall portfolio approach to dealing with the worst year for hydroelectric generation in 74 years of recorded history, unprecedented high forward electric prices, and high electric price volatility. Selecting these resources allowed the Company to secure a portion of its needed supply to serve average expected load and to be prepared to serve load under variable load conditions, variable hydro conditions and variability caused by unplanned generation unit outages. The dispatchable nature of these resources allowed more adaptability to changes in energy prices than a fixed price energy purchase from the market. Only the cost of the equipment or lease was fixed. The variable costs of the projects, including variable fuel costs, would be incurred only when the power market prices were higher. This allowed the Company to save some costs if the market declined. If the Company had made a forward market purchase, the full cost of that purchase would be fixed even if the market declined. Therefore, this portion of the Company's portfolio of resources acquired to fill the resource gap resulting from historically low hydroelectric generating conditions allowed for more flexibility and lower comparable cost.

Q. Were the small generation projects re-evaluated as power market conditions changed?

A. Yes. On June 19, 2001 a review of the five originally selected small generation projects was conducted. New dispatch models and economic models were run for the Othello CT, Boulder Park and SIP projects that were long-term purchases of equipment. New economic models were run for the Devil's Gap and Kettle Falls Bi-Fuel Projects. Attached as pages 1 and 2 of Exhibit No. __(RJL-21) 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 to yield a net benefit (or cost) to complete the project as shown on page 2 of Exhibit No. __(RJL-21). 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 dispatch/economic models tend to pick up the energy valuation and are most suitable for projects that will operate most of the year. When energy prices were high, these units were expected to operate much of the year during the initial period of the analysis. 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 all projects, to differing degrees, had negative benefits, or costs, at the June 11, 2001 analysis date due to the change in the projected forward price for electric power. Kettle Falls Bi-Fuel showed a negative $203,000 value and was therefore only somewhat below breakeven compared to the current market.

The net benefit of the projects compared to the value of a one-year call option premium showed that Boulder Park, Kettle Falls Bi-Fuel and Devils gap still had value compared to the market. The variable operating costs for the projects ranged between $50/MWh and $90/MWh.

The Othello CT project cost to complete was $8.3 million higher than the premium for a one-year call option indicating that it would be more cost-effective to terminate this project. The Othello CT project was cancelled and the Company is in the process of looking for a buyer for the combustion turbine.

The Spokane Industrial Park project showed a cost to complete of $2.2 million higher than the premium for a one-year call option. This project was continued because the generation units were efficient (low heat rate), were identical to the six generation units being sited at Boulder Park, the option value would extend beyond one year, and because the Company had a resource need for peaking capability. However, because of the tight cash flow constraints of the Company, this project was terminated in August 2001. The two 4.1 MW generating units were under order with no cancellation provisions. Therefore, the Company is currently pursuing two options in parallel with regard to these units. The Company is assessing the potential installation of the units at Boulder Park, if air emissions testing of the first six generation units on the site will allow for siting of two additional generators. The use of common infrastructure facilities at the Boulder Park site can reduce the incremental cost of installation of these last two units. In case emission limits do not allow all eight units to be sited at Boulder Park, the equipment vendor has been offering the units for sale on behalf of the Company.

The cost to complete Boulder Park, Kettle Falls Bi-Fuel and Devil's Gap was either below or approximately equal to the premium for the one-year call option. Therefore, those projects were continued. In addition, prices in heavy load hours, in many forward months, were still at levels at or above the marginal cost of operating the remaining small generation units. On June 19, 2001, forward market prices for heavy load hours were: July/2001- $116/MWh; August/2001 - $129/Mwh; Sept./2001 - $108/MWh; Q4/2001 - $103/MWh; Q1/2002 - $85/MWh; and Q3/2002 - $90/MWh.

By September 2001, there was no point in the upcoming 10 months where the leased Devil's Gap diesel reciprocating engine generation project was projected to be economic to operate. Given that projection and because of the Company's tight cash situation, in August 2001 the Company decided to negotiate termination with the equipment lessor. The Company and the lessor of the equipment subsequently met and agreed on a settlement cost of $7.1 million which was a $3.4 million savings compared to following the terms of the original lease to conclusion.

VII. 2001 NECT - New Emission Control Equipment

Q. Please explain the addition of new emission control equipment for the Northeast Combustion Turbine (NECT) facility.

A. Company engineers, in late 2000, identified a means to reduce emissions from the NECT plant and increase operating hours from 500 hours annually to approximately 3,000 hours of full operation. The new equipment has been installed. The Company and the vendor are working through an equipment tuning process necessary to make the adjustments needed to prove out the equipment performance. <u>The Company's commitment to the installation of this new pollution control equipment was also a key part of the negotiations with the various parties to allow NECT to operate additional hours in 2001 under the Governor's Energy Alert.</u>

Q. Please explain why the installation of new pollution control equipment at NECT was prudent.

A. Additional hours from NECT were needed to offset high priced market purchases that the Company would otherwise have to incur in order to meet its load obligations. Investing the approximately $3 million for new pollution control equipment for Northeast provides a low cost option to generate power at the marginal operating cost of the unit. One approach to evaluating this project is to value it similar to a call option. NECT is a dispatchable peaking unit. The marginal cost of this option is less than $6.00/MWh. While currently there is no market offering for call options due to the high volatility of energy prices, this is a very low premium to pay for a strike price at the variable operating cost of the unit. If one uses a $4.00/MMBTU cost for natural gas, the variable operating cost of this unit is approximately $57/MWh. The calculation of these values is shown in attached Exhibit No. __(RJL-22). On December 4, 2000 when this project was being evaluated, the forward heavy load hour prices for energy in third and fourth quarter 2001 were $250/MWh and $145/Mwh respectively.

VIII. 2001 Kettle Falls CT

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

A. Company engineers, in early 2001, identified 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 feedwater heater for the existing Kettle Falls wood waste fueled generator. The additional heat that is provided to the wood waste project feedwater heater increases the generation capability of the existing plant by approximately 2 MW. Completion of the project was planned for the first or second quarter of 2002.

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

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 spreadsheet is included in Exhibit No. __(RJL-23). 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 positive 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 change?

A. Yes. On September 12, 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 25-year economic analysis showed a positive net present value of $4 million over 24 years compared to purchasing energy in the market. Page 6 of Exhibit No. __(RJL-23) shows the re-evaluation and the economic analysis of the marginal cost of completing the project. The project is moving forward, but completion has been delayed until July 2002.

IX. 2002 Coyote Springs II 50% Sale of Project

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

A. Yes. Although the rapid decline in forward power market prices has changed the valuation of the plant, the Company still believes that the CSII project is a good long-term resource. In the Company's recent surcharge proceeding before the Commission in Docket No. UE –010395, Company witness Peterson discusses the Company efforts to secure project financing for the CSII project on pages 5 through 7 of his direct testimony. Peterson explains in his testimony that, due to the Company's current financial condition, it has not been possible for the Company to secure construction financing for the project.

Q. What options did the Company consider with regard to disposing of all or a portion of the CSII project?

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 monthly dispatch analysis was performed for each proposal and compared to replacing the entire plant with a market purchase of energy. The economic analyses of those proposals are attached as Confidential Exhibit No. __(RJL-C24).

Q. Please describe the proposals in general terms and the results of the Company 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. In year 2003, the RW Beck long-term price forecast for electricity and natural gas was used.

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 helps the Company's near-term financial situation, and allows the Company to diversify its portfolio as it seeks to fill future resource needs that begin in 2004.

X. New Company-Owned Generation – Non-Fuel Operating Costs

Q. Has the Company prepared a forecast of operations and maintenance cost for the CSII, Boulder Park, and Kettle Falls CT generation projects?

A. Yes. The Company has prepared spreadsheets that itemize the components that build up to the total non-fuel operating costs for the CSII and the Boulder Park generating projects during the pro-forma year. The Kettle Falls CT generating project is not expected to materially add to the operating costs of the existing Kettle Falls generating project during this pro-forma period. Therefore, no additional operating costs are included for the Kettle Falls CT project in this proceeding.

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

A. The Company's share of operating costs for the CSII generating project are projected be approximately $2,828,133 for the pro-forma year, November 1, 2002 through October 31, 2003. This amount represents the Company's 50% share in CSII. The Company's expected operating costs for CSII are shown on page 1 of Exhibit No. __(RJL-25).

The Company has signed an Operations And Maintenance Agreement with Portland General Electric Company (PGE), the operator of the Coyote Springs I generating plant which is located directly adjacent to the CSII project. Under that agreement, PGE will operate the CSII plant for a fee under that agreement for the Avista and Mirant partners. Avista/Mirant will benefit from lower staffing levels and other operating costs shared with PGE as opposed to separately staffing and operating CSII as an independent generating project. PGE has provided the Company with a budget of the monthly operating costs for CSII. In addition, the Company has included known costs associated with water and land use at the Port of Morrow. The Company has included the costs that it expects to incur as part of a major maintenance contract with a third-party vendor. The vendor has provided fixed and variable costs as part of a draft contract agreement and those costs have been included in the Company's operating cost for CSII.

Q. What operating costs are expected for the Company's Boulder Park generating project?

A. The Company's operating costs for the Boulder Park generating project are projected be approximately $356,683 for the pro-forma year, November 1, 2002 through October 31, 2003. The Company has estimated the operations costs for six 4.1 MW generators at the site. The Company has not included additional incremental costs for the two identical generation units that the Company plans to relocate from the Spokane Industrial Park site to the Boulder Park site pending outcome of emissions testing at the Boulder Park site. The Company's expected operating costs for Boulder Park are shown on page 2 of Exhibit No. __(RJL-25).

The Company's projection of operating costs for reciprocating-engine driven generating units at Boulder Park were developed in a detailed spreadsheet that includes cost components for these units that are consistent with the manufacturer's recommendations. Additional cost items on the spreadsheet include the Company's incremental labor to perform operations and maintenance duties, and other costs associated with operating the project.

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

A. Yes it does.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-1)

AVISTA'S RESOURCE PLANNING AND POWER OPERATIONS

Company-Owned Resources

The Company owns and operates two hydroelectric projects on the Clark Fork River in Western Montana and Northern Idaho, and six hydroelectric projects on the Spokane River. These projects are listed below along with the number of generating units at each project, the dependable capacity of each project, and the estimated amount of energy from each project under both average (normal) streamflow conditions and "critical" streamflow conditions, as determined in the latest Northwest Power Pool Regulation Study.

Hydroelectric Projects Summary

Generating Project	Units	Dependable Capacity (MW)	Average Energy: Average Water[1] (aMW)	Average Energy: Critical Water[2] (aMW)
Clark Fork River				
Noxon Rapids	5	554	203	131
Cabinet Gorge	4	236	122	87
Subtotal	*9*	*790*	*325*	*218*
Spokane River				
Post Falls	6	18	10	7
Upper Falls	1	10	9	8
Monroe Street	1	15	13	12
Nine Mile	4	24	16	13
Long Lake	4	88	52	44
Little Falls	4	36	23	18
Subtotal	*20*	*191*	*123*	*102*
Total Hydro	**29**	**981**	**448**	**320**

[1] Based on NWPP 2001 60-year (1928-88) study

[2] Based on NWPP 2001-02 Final Regulation study

In addition, the Company owns and leases the following thermal generating projects:

Thermal Projects Summary - 2003

Generating Project	Units	Primary Fuel	Capacity (MW)	Energy (aMW)
Colstrip[3]	2	Coal	222	190
Kettle Falls[4]	1	Woodwaste	49	42
Kettle Falls CT[5]	1	Gas	7	7
Rathdrum[6]	2	Gas	164	135
Northeast[7]	2	Gas	59	12
Coyote Springs II[8]	1	Gas	136	117
Boulder Park[9]	6	Gas	25	23
Total Thermal	**15**		**662**	**526**

Retail Electric Load Forecast

Each year the Company prepares a five-year electric retail load forecast. Every other year the Company prepares a ten-year electric retail load forecast. The forecasts include the Company's needs for both energy and capacity to serve retail load requirements. In developing the five-year forecast, the Company uses econometric

[3] Avista owns 15% of Units 3 and 4 which are operated by PP&L Montana.
[4] Kettle Falls is owned and operated by Avista Utilities.
[5] Kettle Falls CT is a Solar natural gas turbine that will be installed at the site of the existing wood waste project. High temperature exhaust from the CT will be used to produce steam in a boiler. The CT boiler steam will be added to the steam from the wood-waste boiler in the main plant to increase output.
[6] Rathdrum was constructed by Avista, but is leased through a sale and lease-back arrangement. Avista operates the project. Air emission restrictions currently limit each unit's operation to 8,424 hours per year per unit.
[7] Northeast is owned and operated by Avista. Air emission restrictions currently limit operation to approximately 500 hours per year. New pollution control equipment has been purchased that would increase the number of hours to 2000 per year per unit. The new equipment is expected to be in early 2002.
[8] Construction began on the Coyote Springs II combined-cycle combustion turbine project in January 2001 and is expected to be completed by June 1, 2002. The Company is in process of selling one half of the plant to Mirant.
[9] Construction began on the Boulder Park natural gas reciprocating engine peaking plant in August 2001 and is expected to be completed in January 2002.

models to produce kilowatt-hour sales and customer forecasts. The econometric models are systems of algebraic equations that relate past economic growth and development in the geographic communities, with the past customer growth and power consumption in those same communities. Each year the forecast incorporates changes that occur in the regional and national economy, which affect the Company, such as industrial activity, residential use, population growth and income levels.

This five-year forecast is extended for an additional five years, for longer-term resource planning purposes, based on the methodologies and equations described above for its annual five-year forecast.

The forecasted annual capacity and energy figures for years 2002 through 2011 are shown on line 1 on page 8 of this Exhibit. The forecast shows an annual average energy load of 986 aMW in 2002. The Company's retail energy load is forecasted to be 1285 aMW in 2011, a compound growth rate of 3.0 percent per year.

The capacity forecast shows 1,584 MW in 2002, increasing to 2,057 MW in 2011, a compound growth rate of 2.9 percent per year.

The Company's retail energy loads grew from 838 aMW in 1991 to 1,066 aMW in 2000, a compound annual growth rate of 2.7 percent. The Company's retail capacity loads grew from 1,479 MW in 1991 to 1,616 MW in 2000. The compound annual growth rate was 1.0 percent.[10]

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[10] These figures represent the actual loads experienced by the Company and reflect the actual temperatures that occurred during each of the respective periods, which would affect the calculated annual growth rate.

Long-Term Loads and Resources Picture

The table on page 8 of this Exhibit includes a tabulation of Avista's Requirements and Resources (Load and Resource, or L&R Tabulation) on an annual basis for the next ten years.

The "Peak" columns include peak load "Requirements" in January of each year, the highest one-hour forecasted capacity requirement in each of the years. The "Resource" peak numbers represent the maximum available capacity output from the Company's resources to serve the one-hour peak. The "Avg" columns in the table include the expected average energy for the twelve-month period for both loads and resources.

The Company's requirements are shown on lines 1-8. These requirements include the Company's retail native load shown on line 1, long-term firm wholesale contract obligations on lines 2-7, and Capacity Reserves on line 8.

Resources available to the Company are shown on lines 10-27. The Company's owned hydroelectric generation on the Clark Fork and Spokane Rivers is included on line 10. The "Contract Hydro" on line 11 includes the contracts Avista has with Douglas, Chelan and Grant County PUDs for a portion of the output from the Wells, Rocky Reach, Wanapum and Priest Rapids hydroelectric projects on the middle section of the Columbia River (Mid-Columbia projects). Contract Hydro incorporates a contract extension with Grant County PUD for output from their Priest Rapids and Wanapum projects.

Lines 12-27 include power available to the Company from long-term firm contract rights and the Company's thermal generating resources. For long-term planning, the Company shows peaking turbine annual energy output based on the amount those units would be expected to operate on a monthly basis to serve load under monthly critical hydro conditions. A comparison of the total resources with the total system requirements yields the surplus or deficiency on an annual basis. These values are shown on line 29.

The "System Hydro" and "Contract Hydro" figures in the L&R Tabulation reflect energy that could be produced under "critical" water conditions, as determined by the Northwest Power Pool hydroelectric regulation model. The NWPP currently uses the eight-month period September 1936 through April 1937 to represent the "critical period." The critical period includes the lowest level of available hydroelectric generation for a one-year period during the 1928-1988 study period.

The L&R Tabulation includes an analysis of annual average firm energy loads and resources. The Company uses critical water conditions in its L&R Tabulation because energy produced by the hydroelectric system under critical water conditions is considered firm energy. Firm energy represents the amount of energy that can be depended upon, even under what has historically been the most adverse streamflow conditions.

The capacity tabulation provides a view of the Company's forecasted peak loads and peak resources, including capacity reserves. It indicates the maximum hourly load, and the resources available to the Company to meet that load on a firm basis. Values are presented for the month of January, since this is the month during which the Company forecasts its peak to occur. Thermal and hydroelectric resource capabilities are based on their "dependable capacity". Contracts include the peak capability identified within them.

Reserves, as shown on line 8 of the L&R Tabulation, play an integral part in maintaining system reliability to serve firm loads. The planning reserves shown on this tabulation are carried to provide the Company with adequate generating capacity during periods of extreme weather or unexpected plant outages. Included in the reserves component are capacity to meet the contingencies of temperature affects on retail load (cold and hot weather), generator-forced outages, and possible river freeze-up at our hydroelectric plants. The Company plans for reserves in an amount equal to ten percent of firm peak loads, plus ninety additional megawatts to account for river freeze-ups and forced outages. On a day-to-day operating basis, the Company is required by the Western System Coordinating Council (WSCC) to carry operating reserves equal to 7% of the Company's online thermal resources and 5% of its online hydroelectric resources. Planning for reserves in the long-term L&R Tabulation provides the Company with the necessary operating reserves over time.

The L&R Tabulation provides an indication of the Company's need for firm capacity and energy resources over the ten-year forecast period. The L&R Tabulation on page 8 includes the following surpluses and deficiencies for the respective years:

	Surplus/(Deficiency)	
Year	Capacity MW	Energy aMW
2002	9	(20)
2003	165	(8)
2004	(108)	(131)
2005	(229)	(166)
2006	(293)	(179)
2007	(353)	(210)
2008	(417)	(260)
2009	(486)	(280)
2010	(550)	(315)
2011	(613)	(355)

The results show an energy deficient condition in all years, although the deficits in the first two years are relatively small. The study also shows a need for capacity beginning in 2004.

AVISTA CORP.

Requirements and Resources

figures in MW (critical water)

Line No.	REQUIREMENTS	2002 Pk	2002 Avg	2003 Pk	2003 Avg	2004 Pk	2004 Avg	2005 Pk	2005 Avg	2006 Pk	2006 Avg	2007 Pk	2007 Avg	2008 Pk	2008 Avg	2009 Pk	2009 Avg	2010 Pk	2010 Avg	2011 Pk	2011 Avg
1	System Load	1584	986	1612	1006	1665	1040	1728	1079	1776	1109	1828	1142	1884	1177	1946	1215	2003	1251	2057	1285
2	PacifiCorp Exchange	0	3	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Puget #2	33	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	PacifiCorp 1994	0	12	0	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	PGE #1	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0
6	BPA-WNP #3	0	32	0	32	0	32	0	32	0	32	0	32	0	32	0	32	0	32	0	32
7	Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	Reserves	248	0	251	0	256	0	263	0	268	0	273	0	278	0	285	0	290	0	296	0
9	TOTAL REQUIREMENTS	2016	1059	2014	1054	2072	1073	2142	1112	2195	1142	2252	1175	2313	1210	2382	1248	2444	1284	2504	1318
	RESOURCES																				
10	System Hydro	973	320	973	320	973	320	973	320	973	320	973	320	973	320	973	320	973	320	973	320
11	Contract Hydro	196	74	196	74	196	74	196	75	181	80	178	79	175	78	175	78	173	77	170	69
12	Can Ent Return	-8	-4	-8	-6	-11	-6	-12	-6	-8	-5	-8	-5	-8	-5	-8	-5	-8	-5	-8	-4
13	Small Power/Upriver	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
14	Northeast CTs	47	11	59	12	59	12	59	12	59	12	59	12	59	12	59	12	59	12	59	12
15	Kettle Falls CT	0	3	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
16	Boulder Park	25	19	25	20	25	21	25	21	25	21	25	21	25	21	25	23	25	23	25	23
17	Rathdrum CTs	164	112	164	69	164	109	164	116	164	125	164	128	164	116	164	130	164	132	164	135
18	SEMPRA	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	PacifiCorp Exchange	50	3	50	3	50	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Entitlement & Supplemental	4	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	BPA Res. Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	BPA-WNP #3	82	42	82	42	82	42	82	42	82	42	82	42	82	42	82	42	82	42	82	42
23	CSPE	9	5	8	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	TransAlta-Centralia	200	143	200	143	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Thermal- Kettle Falls	49	42	49	42	49	42	49	42	49	42	49	42	49	42	49	42	49	42	49	42
26	Colstrip	222	186	222	190	222	190	222	190	222	190	222	190	222	190	222	190	222	190	222	190
27	CS II CCCT	0	64	136	117	136	117	136	115	136	117	136	117	136	115	136	117	136	117	136	115
28	TOTAL RESOURCES	2025	1039	2179	1046	1964	942	1913	946	1902	963	1899	965	1896	950	1896	968	1894	969	1891	963
29	SURPLUS (DEFICIT)	9	-20	165	-8	-108	-131	-229	-166	-293	-179	-353	-210	-417	-260	-486	-280	-550	-315	-613	-355

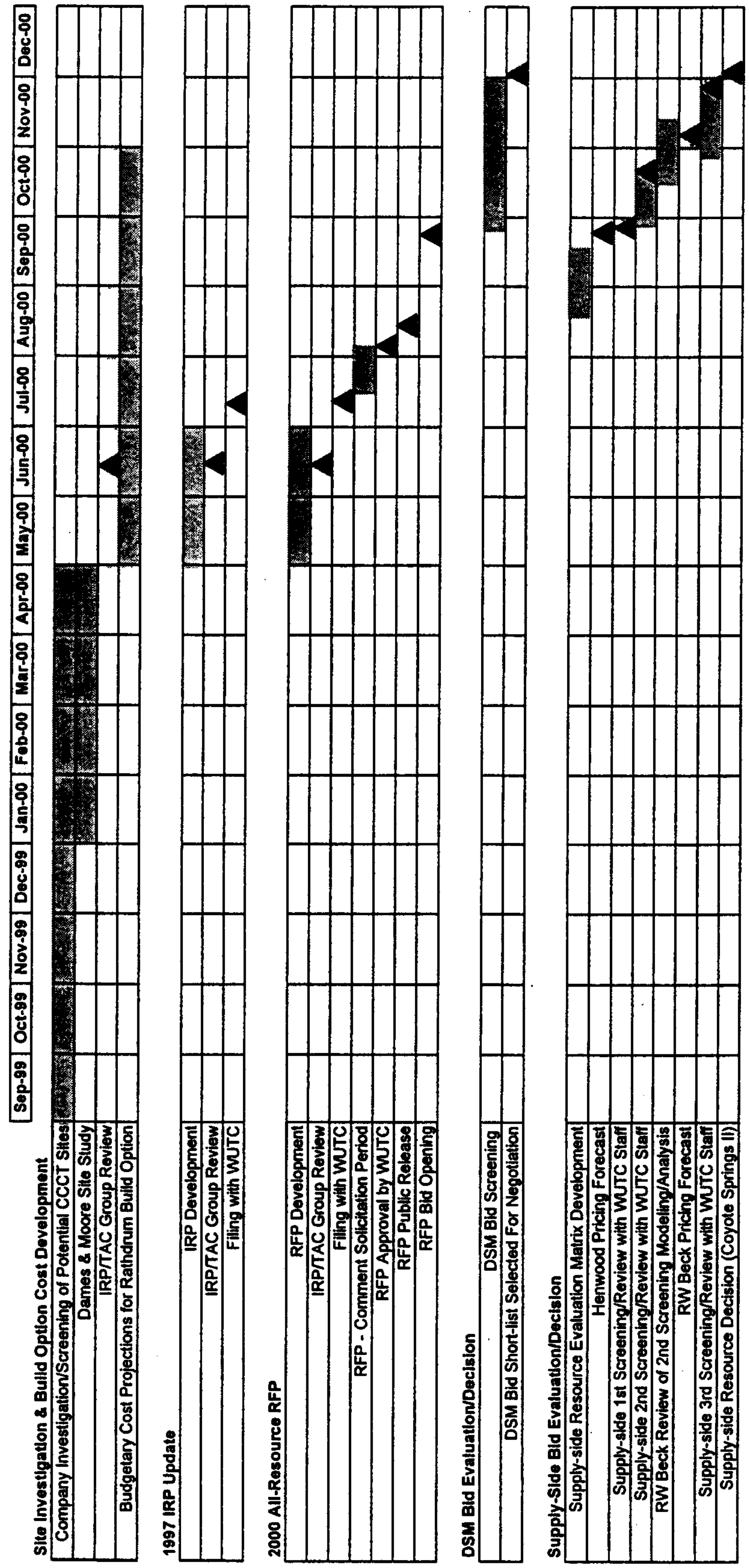
BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-2)

2000 Resource Acquisition Process - Timeline



The following report outlines the resource planning, data gathering, evaluation and selection process that has been a focus of a concentrated work effort by Avista Corp staff and others outside of the Company. The intent of the report is to provide an overview of the entire selection process. Avista has extensive documentation records that were kept throughout the work effort. Those records are available to provide the details supporting the decisions that were made by the Company. Many of those records contain confidential bids and proprietary analysis done by third parties. Certain information is therefore intentionally kept general in this report to avoid inappropriate disclosure.

<u>Planning & Determination of Resource Need</u>

Fall 1998 Through Spring 2000 — **Centralia Sale**

- On October 30, 1998, the Centralia owners approved moving forward with a plan to put the entire generating plant and mine up for sale.
- In November 1998, the Centralia plant was put up for formal bidding.
- On May 7, 1999, the Centralia TECWA was selected as the winning bidder. The mine owners executed a sale agreement with TECWA dependant on obtaining board and regulatory approvals and upon resolution of several other plant and mine related issues.
- On May 5, 2000, the Centralia power plant was sold to TECWA by the joint owners.

Fall 1999 — **Medium-Term Power Purchase**

- In October 1999, the Company contracted with TECWA for 200MW of capacity and energy for Q1, Q2, and Q4 contingent on the sale of the plant and continuing through 12/31/03. A contingent purchase was most beneficial due to the real uncertainty as to whether all of the sale contingencies could be worked through satisfactorily.

Fall 1999 Through Spring 2000 — **Resource Site Option Investigation**

- The Company began meetings in August to discuss resource projects in the Pacific Northwest region that were felt to be possible long-term resource candidates. A list of likely sites in the region was made. All of the projects were combined cycle natural gas combustion turbine sites.
- From September through November, a total of 32 project sites were visited. Information was collected regarding permitting status, construction schedules, potential costs, unique issues, etc. Air permit issues, water source issues, water discharge issues, community support issues, electric transmission, natural gas transmission, etc. were part of the data gathered from the different meetings and visits. The company considered the prospect of a project consisting of either

one or two combined cycle combustion turbines. The assumption was that a two-unit project would be a partnership arrangement where a third-party would take on the obligations of the second unit. Both parties would share in the economies of scale that occur when two units are managed together at one location. Alternatively, the second unit could still be built at a later date.

Avista CCCT Initial Siting Study [CCCT Turbine Site Study – Book #2]

- November through December, company staff processed through information gathered on different sites in a series of meetings. Sites with significant roadblocks were eliminated through a group review process. Five sites were selected for further evaluation and study. Those sites were: Rathdrum, Idaho (at the current simple cycle project location); Kaiser Mead; Hermiston, Oregon; Starbuck, Washington; Vanalco (near Vancouver, WA).
- In January 2000, the company contracted with Dames & Moore to perform a more thorough site evaluation on those project sites identified. Some of the evaluation areas were air permit issues, water source issues, water discharge issues, noise issues, etc. The consultant was asked to consider issues and suitability of the site relative to place either one 250MW combined cycle turbine or two 250MW combined cycle turbines (500MW total) at each of the sites. The relative benefits of one project site over another can change depending on whether one or two combined cycle turbines are planned. The company wanted these differences identified.

"Pacific Northwest Combined Cycle Combustion Turbine Generation Facility Siting Study" [CCCT Turbine Site Study – Book #2]

- April 2000 saw the completion of the Dames & Moore project site study. Rathdrum was the top ranked project site for a single combined cycle turbine. Kaiser-Mead ranked as a top project site for a two unit project.
- The Dames & Moore study was reviewed with the IRP TAC group on 6/22/00.

Spring 2000 **Updated Resource Plan/Criteria**

- The company reviewed various planning issues along with updating the company's Load & Resource tabulation showing the removal of its share of the output from Centralia in mid-year 2000. One planning factor that was changed was the degree to which the company would plan to rely on the short-term market to meet load obligations. However, as prices continued to rise in the late spring of 2000, the company concluded that it should reduce its reliance on the short-term market to meet planned resource requirements. The L&R showed over 300aMW of need in 2004. A similar amount of annual capacity need was also shown.
- In addition to looking at annual capacity and energy L&R positions, the company also looked at the month by month L&R position during on-peak and off-peak times. The company reviewed its position monthly over several years. Again, 2004 showed significant deficits and therefore would be the focus of future discussions regarding the

company's resource need.

WUTC & IPUC staff meetings. [Planning-Need Book #3]

- The company met with the WUTC staff on 5/23/00 and the IPUC staff and commissioners on 6/2/00. The purpose of those meetings was to review the company's Load & Resource tabulation, the size and timing of resource need, the types of resource options, and the process or steps that the company should take to select resources for filling the identified needs. The company laid out some general concepts for the all-resource RFP. The company also developed and presented "deficiency duration curves" showing the percent of time that the company would be deficient a certain amount of power using the Prosym hourly dispatch model and 60 years of hydro data. The area under the curve gives a good general indication of the amount of energy needed to meet resource requirements. (Peaking plants were removed from the resource stack in this presentation of data, and then they were shown added back to show how they fit peak needs.) A base load resource, such as a combined cycle combustion turbine, was shown to fit the deficiency gap.
- The company began work on a 1997 Integrated Resource Plan Update at the suggestion of the WUTC staff. We discussed that it was most expedient to file an update of an already filed and accepted plan in order to get an official acceptance of resource need from the commission. The other alternative would have been to file the IRP that was in progress. This would have taken much longer to get commission review and acceptance. The company proceeded to address key areas of the plan, identified by WUTC staff, that would require updating.

Spring 2000 **Updated 1997 IRP**

- The IRP is a long-term planning tool used to determine Avista's energy and capacity balance for a ten-year period. The IRP itemizes Avista's peak and average loads, firm contract resources and obligations, and power plant energy production and capacity (under critical water conditions) on an annual basis. Netting these numbers illustrates Avista's annual surplus or deficit energy and capacity position to serve native load.
- Due to changes in the native load forecast, changes in power plant ownership, and changes in long-term firm contract resources and obligations it was necessary to revise the 1997 IRP to show the most current load and resource position. The IRP was revised and submitted to the WUTC on July 12, 2000. The IRP shows Avista deficit in load and resource balance through 2003 under critical water conditions. In 2004 and beyond, the IRP shows Avista requiring up to 300 MW of energy and capacity to meet native load requirements.
- Avista used the 2000 Gas IRP as a starting point for the 1997 IRP Update electric price forecast. It is reasonable to assume that a new generation combined cycle combustion turbine is the likely marginal

resource of the future. Applying historical spark spreads to quantify a possible electric forecast is a reasonable method to show how a new resource may fair under different market conditions.

June/July 2000 **IRP/RFP Review**

IRP Technical Advisory Team Meeting [Planning-Need Book #3]

- Because of the need for substantial long-term resources, the company developed drafts of an all-resource request for proposals (RFP). The company developed a draft RFP during May and June 2000.
- On 6-22-00, company staff reviewed the basic components of the 1997 IRP Update with the IRP Technical Advisory Committee (TAC) in Spokane. WUTC staff, IPUC staff, Northwest Energy Coalition, and Northwest Energy Services were in attendance at the meeting and provided some comments. Company staff reviewed the Prosym hourly dispatch model that was being used to evaluate resource options. The Company's natural gas and electric price forecasts were discussed. The company also shared draft copies of the proposed all-resource RFP. The RFP would assess options available in the market to compare to its own company sponsored projects. Company staff also made a presentation regarding the company's new resource site investigation process including the Dames & Moore site investigation study.
- The company followed up with WUTC staff, IPUC staff, Washington State Public Council, Industrial Customers of Northwest Utilities, Washington Dept. of Community, Trade and Economic Development, and Northwest Energy Coalition to get comments on both the 1997 IRP Update and the proposed RFP. Various comments were received and worked through. The company shared ProSym model run data showing how the Avista resources would be modeled with commission staff.

July/August 2000 **IRP/RFP Approvals**

IRP and RFP Filed With WUTC & IPUC [Planning-Need Book #3]

- On July 12, 2000, the 1997 IRP Update (IRP) was filed with both commissions to supplement the Company's previous plan filed pursuant to WAC 480-100-251 in Washington and by Idaho Order No. 22299. The RFP filings were based on the Company's IRP. As described in the preceding sections, Avista's revised loads and resources demonstrated a need for power.
- Avista Corp filed its Request For Proposals (RFP) with the WUTC on July 13, 2000 and with the IPUC on July 12, 2000. The RFP indicated that the company was seeking proposals for approximately 300 MW of capacity and energy and that flexibility/dispatchability of a resource was a preference. Proposals were sought on all resource types. Renewable resources were given a 10% price credit.
- The RFP was filed pursuant to the WUTC's rule requiring solicitation of competitive bids under WAC 480-107. The Company

opted to file identical copies with IPUC for purposes of keeping the Idaho Commission abreast of resource procurement issues on the same timeline.

- The Company met with Commission Staffs prior to each filing as described in preceding sections. These meetings, in combination with Avista's June IRP Technical Advisory Committee meeting, allowed the Company to gain stakeholder input prior to the release of the RFP.
- On July 12, 2000, the company mailed copies of the filed RFP to 22 potential bidders or interested parties for their review and comment.
- On July 18, 2000, the WUTC formally noticed the filing of Avista's RFP and requested comments by August 8, 2000.
- On July 21, 2000, the IPUC formally noticed Avista's RFP and requested comments by August 11, 2000.
- On August 2, 2000, company representatives met with IPUC staff and Commissioners in Boise to review the 1997 IRP Update and the RFP and to respond to questions.

RFP Approved by WUTC and recognized by IPUC. [Planning-Need Book #4]

- On August 9, 2000, the WUTC heard commission staff, intervenor and company comments on Avista's all-resource RFP. The WUTC Commission Staff developed a memorandum supporting both the need for resources identified in the 1997 IRP Update and the RFP. The WUTC approved the RFP in Docket NO. UE-001081.
- IPUC staff issued their recommendations on August 11th noting that issuance of the RFP was an appropriate action. On October 10th, the IPUC issued Order No. 28542 regarding the RFP, in Case NO. AVU-E-08 noting that approval is not necessary. The IPUC stated "the Company is commended for soliciting public input into its RFP process."
- As an ongoing process, the Company agreed, as part of the Commission approvals, to provide the Staffs access to all materials needed to review the final evaluation system before the bids were opened. Further, the Company committed to sharing all modeling and analysis with the Staffs for the purpose of verifying the final selections.
- The RFP was released to the public on August 14, 2000. The RFP and the 1997 IRP Update were published on Avista's web-site. An announcement was posted in newspapers in Spokane, Seattle and Portland. Media was contacted and interviews were conducted regarding the Company's need for resources and the RFP. The company asked for bids to be returned by September 18, 2000.

Evaluation and Decision-Supply Side

Sept.- 2000 **Supply-Side Evaluation Matrix Development**

- Avista determined that a first screening would ensure that bid proposals met required criteria as stated in the RFP. Bidders were to provide general qualifications as outlined in the RFP plus the project specific information requested for each proposal submitted.
- The RFP document laid out the three principle areas that would be the focus of further evaluation: Electric power characteristics; finance/price characteristics; and social/environmental characteristics. The company had committed to commission staff to develop a more detailed evaluation matrix based on the principle areas prior to the opening of RFP bid proposals.
- The company developed a set of financial/price and non-price factors with associated weightings. This evaluation matrix and write-up describing the various weightings and the ranking process was reviewed with WUTC and IPUC staff members on September 13, 2000.

Review RFP Evaluation Process with WUTC/IPUC staff [Planning-Need Book #4]

Financial/Price Factors

- To provide a consistent evaluation framework, the Screening Work Group developed a matrix to evaluate all supply-side proposals against. The matrix contained the categories of Financial/Price Evaluation Factors, and Non-Price Evaluation Factors. Financial/Price factors received a 65% total weighting. Within this category, three sub-categories, and their weightings, were assigned. The Financial/Price Factors were: economic benefits (35%); financial performance capability (15%); and fuel price risk (15%).
- Economic benefits assessed the net savings, on a per-MWh basis, that each proposal brought to the Company's resource portfolio.
- Financial Performance Capability assessed the likelihood that the bidder had the financial ability to complete the proposed project.
- Fuel Price Risk quantified the potential for the price of the proposal's fuel source to change significantly. For example, flat purchase contracts that were not tied to the price of an underlying fuel source rated highly. Projects consuming natural gas received a lower rating.

on-Price Evaluation Factors

- Non-Price Evaluation Factors received a 35% total weighting. In each category, sub-categories and weightings were assigned. Within the Non-Price Evaluation Factors were: fuel availability risk (5%); Electric Factors (20%); and Environmental Factors (10%).
- Fuel Availability Risk assessed the availability of supply and any risks associated with delivery of the fuel.
- Electric Factors provided an area to evaluate such characteristics as ramping rates, dispatchability, reactive supply, the supply source, and system integration.

- Environmental Factors were designed to ensure adequate permits were available, that environmental laws and regulations were adhered to, and proven technology was used to meet such laws and regulations.

September 2000

Henwood Pricing Forecast [Eval.-Decision Book #2]

Pricing Study – Henwood Energy Services, Inc

- Under contract with Avista, Henwood Energy Services, Inc. (HESI) delivered a WSCC Regional Market Price Forecast study on September 22, 2000. The price forecast included monthly heavy and light load electricity prices and annual gas prices (later updated to monthly gas prices) for the years 2001 – 2022. The wholesale electric and natural gas price forecast was derived from HESI's proprietary *Prosym*™ and Electric Market Simulation System software. [*Prosym*™ performs detailed fundamental simulation of the electric wholesale market on an hour-to-hour basis. Electric production is modeled at the generation unit level while system loads and transmission constraints are modeled on an hourly basis. *Prosym*™ computes market clearing prices and generation production for user-defined transmission zones.]

- As a third party source with recognized expertise in electric and natural gas forecasting, Avista used HESI's electric and natural gas forecast as the source for the second screen RFP economic evaluation process.

- The base electric price forecast was subject to many market variables. Plant availability, plant additions, gas prices, hydro conditions, load growth, and transmission constraints could all affect the future price of wholesale electricity. HESI provided a report (dated September 22, 2000) and a supplemental report (dated December 21, 2000) detailing assumptions made in the electric and natural gas price forecast.

Development Of High and Low Electric Price Scenarios:

- To illustrate the impact of different levels of new capacity additions in the WSCC on wholesale electricity prices, HESI performed an electric price scenario analysis for the period 2001 through 2005. In the underbuild scenario, 9,000 MW of new generation (only capacity that was under construction as of August 2000) comes on line in the WSCC during the 2001-2005 period. The overbuild scenario was simulated by including 23,000 MW of new generation in the WSCC with announced commercial operation dates before 2005. This represents roughly 44 percent of known announced generation in the WSCC. Natural gas prices were assumed to be the same as the base case.

- To quantify a reasonable spread of potential longer term high and low electric price scenarios, Avista used HESI's scenario analysis as a starting point. A paper by Professor Andrew Ford of Washington State University discusses cycles in the electric industry due to overbuilding and underbuilding electric plant. Avista used the frequency interval (7 years) between periods of peak over or under building from Dr. Ford combined with the amplitude of the electric price from the HESI over or under build scenarios to extrapolate a high and a low price forecast through the year 2025. . After discussion with Commission staff, Avista finalized the high/low electric price forecast scenarios by smoothing the over/underbuild data to represent a high and low price forecast.

- The Company extended the price forecasts through 2025 using the growth rate between 2021 and 2022 to meet the need for a forecast of 25-year duration.

September 2000 **Prosym Analysis Methodology**

- Prosym is commercially available production cost modeling tool that optimizes hourly dispatch of company owned or contract generation resources against load requirements, gas and electric price information, and supply or requirements contracts. Avista used *Prosym*™ to estimate costs and benefits to Avista's utility system of the RFP bids and the self-build option.
- The resulting model output quantifies how each RFP bid or self-build resource option meets the hourly requirements of Avista's electric system with the least production cost.
- Models of Avista's system included on-peak and off-peak loads, hydroelectric and thermal generating resources, contractual sales and purchases, and spot-market sales and purchases
- The model was run without proposed resource options and then with each resource proposal individually to determine the net benefit of each resource option to the company.

September 2000 **Economic Analysis/Revenue Requirements Modeling**

- All proposals entering at least the second screening were to be evaluated with an economic spreadsheet model developed by the company. The spreadsheet calculated project benefits/costs by year for the 2001-2025 period, including rate-of-return loadings.
- The economic analysis spreadsheet obtained four columns of annual data for each proposal directly from Prosym: generation, fuel costs, variable O&M and start-up costs, and operating margin net of variable costs. The economic analysis went further to include in its

calculations of margin each proposals fixed costs, including debt service, rate of return, taxes, and transportation.
- Each proposal's final economic analysis value was determined using the operating margin net of all fixed and variable costs on a per-MWh basis.

September 2000

Initial Screening Process

- On September 18, 2000 Avista received 32 proposals for 2,700 megawatts from 23 parties in response to its RFP. Of the 32 proposals, 8 were energy efficiency bids, 6 were for renewable resources, and 18 were supply or unit-contingent offers. Bid proposals were opened in the presence of supply and demand-side company personnel as well as a representative of the WUTC.
- Energy efficiency bids were provided to the DSM workgroup for a parallel analysis and evaluation process.
- Copies of the 24 remaining proposals were distributed to the supply-side Screening Work Group for evaluation. The supply-side Screening Work Group was made up of 12 senior-level Avista employees from varying areas of expertise, including engineering, regulatory affairs, wholesale marketing, resource optimization, finance, transmission, environmental, and natural gas.
- The supply-side Screening Work Group applied their expertise to determine the completeness of each proposal against the requirements of the RFP. Based on its completeness, it was decided by the work group whether a bid proposal should move forward to the next screen.
- Where applicable, certain parties were contacted by telephone to clarify the details of their proposals and in some instances to remove deficiencies in them.
- On September 21 the Screening Work Group gathered to share their findings and screen out those proposals that didn't significantly meet the general requirements set forth in the RFP.
- Letter notifications were sent to three parties on September 22, 2000 stating that their proposals did not significantly meet the general requirements set forth in the evaluated. A verbal review of the process to date was conducted with both WUTC and IPUC staffs.

October 2000

2nd Screening Process

- All supply-side proposals that passed through the Initial Screening Process were evaluated in a 2nd Screening Process that included the price and non-price evaluation factors described above.
- Several parties with proposals in the 2nd screening were contacted by various Screening Work Group individuals to clarify certain proposal details.
- Prosym models were run based on Henwood natural gas and electricity base case forecasts, as well as low and high market electric price scenario forecasts.

- Economic analysis/revenue requirements spreadsheets were generated using all available information.
- The supply-side Screening Work Group convened October 11, 2000 to assign values to the second round screening matrix.
- A short list of five proposals resulted from this screening process step, including market purchases, small hydro, and one utility natural gas-fired turbine option.

Screened to Short List of Seven Projects [Eval. & Decision Book #1]

- Analysis and results of this screening step were reviewed with IPUC and WUTC staff on October 18th and 20th respectively. WUTC and IPUC requested two additional natural gas-fired turbine proposals be included on the short-list, bringing the total up to seven.

November 2000

RW Beck - Resource Analysis Process Review

- RW Beck Consultants were retained to assess Avista's proposal evaluation process.
- RW Beck reviewed the analysis of a representative sample of bid proposals including *Prosym*™ inputs and assumptions, the WSCC Regional Electricity Market Price Forecast Study prepared by HESI, the high and low case electric price scenarios and economic models and analyses used to calculate the expected net benefit of each proposal to Avista's system.
- R. W. Beck recommended additional fine tuning of the analysis including: Resource dispatching against forecasted hourly market energy prices, separate energy and capacity prices used in the analysis, use of monthly gas prices, and modification of price sensitivity cases.

RW Beck's review of Avista's analysis is summarized below:

1. Avista's approach provides a reasonable way to determine which option is most viable
2. Approach taken by Avista provides for a fair comparison of the resource options and does not inherently disadvantage any of the reviewed RFP bids
3. Avista has included the necessary parameters in both the *Prosym*™ modeling and in the economic analyses
4. R. W. Beck did not find any material deficiencies (including miscalculation of formulas or omission of essential data) in the analyses reviewed

RW BeckRFP Bid Analysis Review [Eval.-Decision Book #3]

November 2000 **RW Beck Energy and Capacity Price Forecast**

- **RW Beck Forecast**

RW Beck Market Price Forecast Assumptions and Methodology [Eval.-Decision Book #3]

As suggested in the process review Avista contracted with RW Beck to provide a more detailed energy and capacity electric and gas forecast that included hourly electric prices and monthly gas prices. This granular forecast more closely represents market conditions on an intra-day basis when generation capacity approaches load requirements. As seen recently in the western power market, as load requirements approaches supply limits, dramatic price spikes can and will occur. While it was not the intent of this long-term analysis to estimate short-term price spikes, the purpose of the more granular analysis was to better represent the volatility in the market. RW Beck's hourly forecast captures price spikes, in a long-term sense, by assuming that the generator on the margin must receive adequate compensation to pay for all fixed and variable costs plus a profit. In a mature electric market, demand is much less than supply during most periods within a year. Occasionally, when load increases dramatically due to weather, machines trip off-line, transmission lines fail, or hydro conditions are poor, demand will approach or exceed supply. Under these circumstances generators must recover all expenses to maintain economic viability in the long-term.

- **Differences between RW Beck and HESI Forecasts**

Avista contracted with HESI to provide a long-term electric price forecast. This forecast was used during the first two screening processes of the RFP review. After retaining RW Beck to review Avista's analysis process, RW Beck suggested using a refined electric and natural gas forecast that included the following:

- Resource dispatching against forecasted hourly market energy prices
- Separate energy and capacity prices in analysis
- Use of monthly gas prices
- Modification of price sensitivity cases

The resulting differences between HESI's forecast and RW Beck's forecast were within a reasonable range of one another on an average basis. However, the granularity of RW Beck's forecast enabled the flexible resources to capture the value of the market on an hourly basis resulting in greater benefits to Avista's system.

- **Sensitivity Analysis**

  In addition to the basecase forecast, RW Beck provided three sensitivity cases in the hourly price forecast. These were:

  1. High Fuel Price Case with natural gas prices 25% higher than the Base Case
  2. Low Fuel Price Case with natural gas prices 25% lower than the Base Case
  3. High Load Case with WSCC loads 1.5% higher than the Base Case

Oct./Nov. - 2000

Third Screening Process

- Short-listed proposals were subject to greater scrutiny in the 3rd screen. Electric and natural gas transportation pricing and availability were verified. Where applicable, project heat rates and generating capacity were adjusted to account for seasonal variances and losses. The Company's Rathdrum project was refined to include two potential configurations.
- Two short-listed parties were removed from further consideration due to transmission and financial performance capability issues.
- R.W. Beck price forecasts for natural gas and electricity replaced the earlier Henwood pricing values. The biggest change was a shift to hourly electricity pricing and loads in Prosym.
- The economic analysis/revenue requirement spreadsheets were updated with all newly available information.
- Coyote Springs 2 became available as a resource option.
- On November 21, 2000 the Screening Work Group re-convened to develop a new matrix for the short-listed proposals and a recommendation for presentation to Company officers.
- Since Rathdrum continued to be a highly ranked project, community meetings were held in the Rathdrum area to discuss the potential of an expansion and accept public comments. A number of interested parties were contacted, including the Kootenai Environmental Alliance, the Pan Handle Health District, the City of Rathdrum, and various other community and neighborhood groups.

Dec. -2000

3rd Screening Results [Eval.-Decision Book #1]

Decision

- Following the conclusion of the 3rd screen, a meeting was convened with the Company officers to discuss the results of the RFP process. Results of the supply- and demand-side efforts were shared.
- On November 28-29 met with IPUC and WUTC staff in Spokane to discuss the results of the 3rd screening. Staff was informed of the expectation that Coyote Springs 2 would be the Company's choice on the supply side. R.W. Beck made a presentation on its new market price forecasts and its review of the Company's RFP process. The

consultant found the Company's process was sufficiently comprehensive and did not bias the results.

- On December 1 a final meeting with Company officers confirmed the recommendation of Coyote Springs II, and that their proposals would not be Springs 2 as the supply-side resource selection, and 3 DSM bids.

Demand Side

Spring 2000 **Updated Resource Plan / Criteria**

- The development of the demand-side portion of the RFP and the process screening, evaluating and selecting proposals benefited from the contributions of several organizations. Substantial input was received from the staffs of the IPUC and the WUTC as well as representatives of the Northwest Energy Coalition, Washington Committee on Trade and Economic Development, Northwest Energy Efficiency Coalition and Northwest Energy Services.
- Modifications to early drafts of the DSM RFP were made to accommodate an expedited timeline without placing an undue burden on potential bidders. Several criteria that were considered unnecessary for the evaluation process were deferred until after the successful proposals were selected. These criteria, including proof of insurance, permitting and licensing and similar requirements, were moved to the due diligence and contracting phase to make the bid development process less onerous.

September 2000 **Demand-Side Evaluation Matrix Development**

- The DSM RFP team acted in concert with the supply-side evaluators to develop a clear and consistent means of evaluating all proposals received under the RFP. Six criteria were identified and weights for the point scores of each characteristic were agreed upon. Both supply and demand-side proposals were to have the same weights applied to price and non-price components of the proposals.
- The criteria arrived at by the DSM RFP team consisted of price (with a weight of 50 out of 100 points), resource dispatchability (15 points), ramping, measure life and persistence (10 points), customer economics and customer service (10 points), bidder credibility (10 points) and portfolio value (5 points).
- A six-stage process for evaluating demand-side proposals was also established at this time. This process was separate from that of the evaluation of supply-side proposals, but the presence of key personnel in both the supply and demand-side teams, the use of the same timeline and the continual feedback regarding revealed avoided costs was established to ensure that an integrated supply and demand-side resource decision would be reached.

- The six-stage process established called was (1) screening of the proposals for completeness, (2) preliminary evaluation of each proposal by a seven-person team selected based upon the nature of the bid as well as establishing sufficient common personnel on each team to ensure consistency, (3) final evaluation side-by-side evaluation of all proposals by a team composed of all of the members of the preliminary evaluation teams, (4) negotiation of short-listed proposals completed by a single team, (5) the completion of due diligence on those proposals selected from the negotiation process and (6) establishing contracts with the selected proposals.
- At the bid opening it was determined at this time that, in addition to the seven demand-side proposals, one proposal submitted under the supply-side portion of the RFP would be evaluated by the DSM team. This supply-side proposal involved the acquisition to capacity from customer-owned generation more appropriately evaluated by those familiar with operations on the customer-side of the meter.
- The eight DSM proposals received were advanced to a three-person DSM screening team. Minor clarifications were required on three proposals, one proposal required the provision of a missing page and one proposal was deemed wholly deficient in substance. Fourteen questions which, if answered completely, would meet the minimum requirements upon which to base a preliminary evaluation was submitted to WSU. Five days later representatives of WSU indicated that they would not be phase.

October - November 2000

DSM Proposal Evaluation and Selection

- Seven preliminary evaluation teams were formed to study and evaluate the remaining proposals. Four of the seven members of each evaluation team were included on all evaluation teams, the other three members were selected to provide expertise specific to the individual proposal. Three of the four common members of all evaluation teams were also included on the supply-side evaluation team.
- During the preliminary evaluation each proposer was contacted by conference call at least once, and usually several times, to clarify the content of the proposal. Preliminary scoring of all proposals were completed at the end of this phase.
- All members of the preliminary evaluation teams staffed the final evaluation process. Initial meetings were convened to discuss capacity and energy proposals, followed by a final meeting of both categories of proposal.
- The final evaluation expanded on the characteristics of the proposals identified in the preliminary evaluation process. Based upon a discussion and ranking of each project for each of the six criteria a final overall scoring and ranking of proposals emerged.
- The last duty of the evaluation team was to determine which of the seven ranked proposals had the potential to be developed into

successful ventures. In this final analysis the lowest ranking two proposals were deemed to be fatally flawed in one or more categories, and were consequently eliminated from consideration.

- The five short-listed proposals were forwarded to a negotiation team. The composition of the negotiation team was such that all individuals were familiar with the proposal characteristics by virtue of their involvement in the evaluation process. Two of the members of the negotiation team were also involved in the supply-side evaluation and negotiation of proposals.
- Each bidder was contacted, usually on several occasions, by the negotiation team as a whole. Bidders were again given the opportunity to explain the characteristics of their proposal, respond to questions and to make voluntary modifications to their proposal. Upon the conclusion of the negotiations each modified proposal received a final evaluation and scoring by the negotiation team. Three of the five proposals under negotiation were selected as successful proposals responding to these questions. The proposal was consequently eliminated in the screening.

December-February 2000 / 2001

Proposal Contracting and Implementation

- Those proposals that had been selected were advanced to due diligence. The due diligence team was originally composed of three and later (due to changes in job responsibilities) four individuals. During due diligence the bidder in being required to complete those portions of the RFP that were deferred in order to facilitate a streamlined bidding process (proof of insurance, permitting, licenses etc.). References, financial and other characteristics deemed critical to the proposal success will also be verified.
- Presuming that selected proposals are satisfactorily completed and critical characteristics verified in due diligence, the contracting phase will complete the RFP. During this phase the bidder and company will commit to contractual form the understandings made during the negotiation process.
- Implementation of the contracted proposals is expected to begin immediately upon the completion of the contract.

Overall RFP Evaluation & Reporting

February 2001

RFP Evaluation

- The Company's documentation of its resource selection process has been compiled for future filing with the Washington and Idaho Commissions. The purpose of the evaluation is to chronicle the circumstances, events and the steps taken in conjunction with the Company's resource decision in 2000.