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;

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[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) | | 2002 | | 2003 | | 2004 | | 2005 | | 2006 | | 2007 | | 2008 | | 2009 | | 2010 | | 2011 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | REQUIREMENTS | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | 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 |

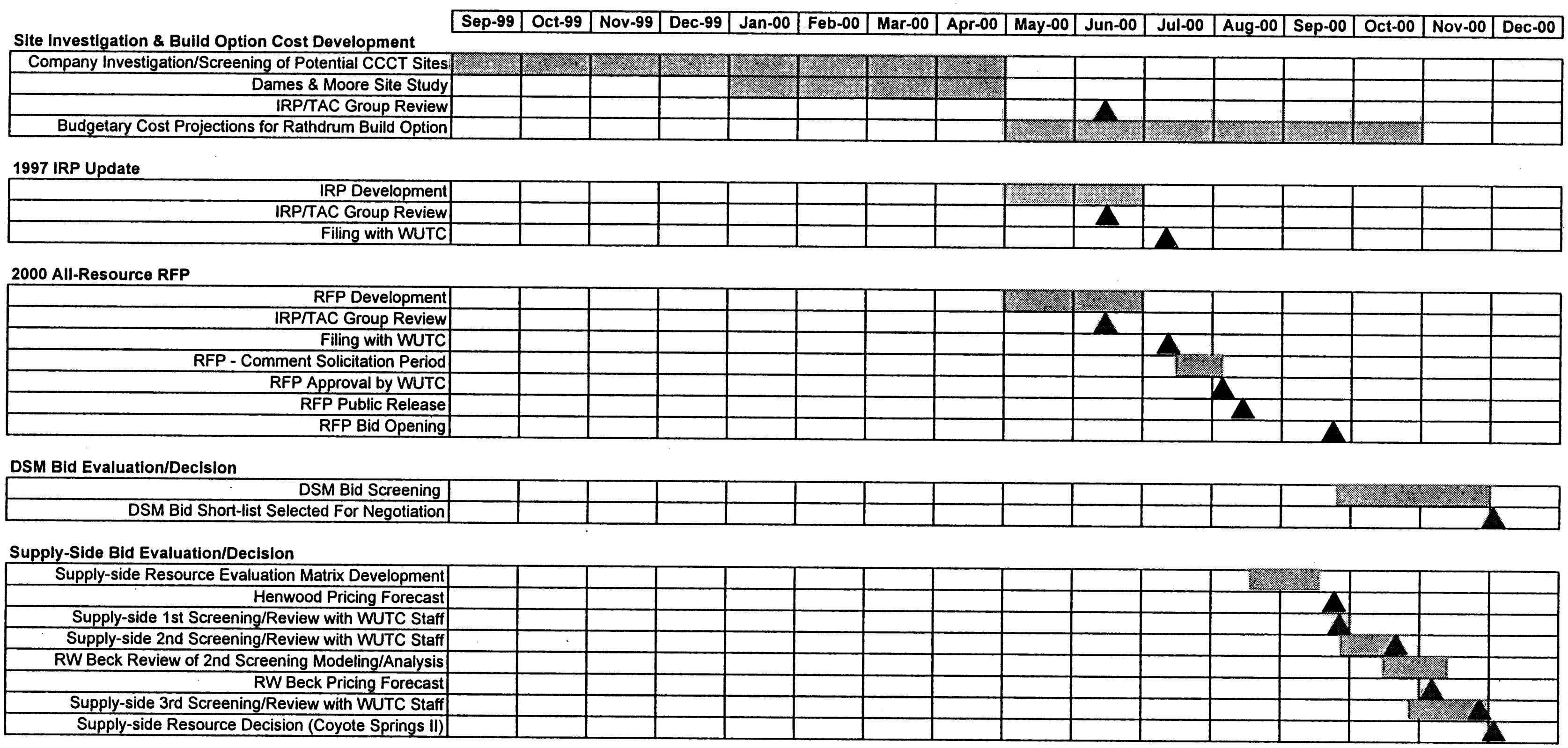
BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-2)

## 2000 Resource Acquisition Process - Timeline



# AVISTA CORP
# 2000 RESOURCE SELECTION PROCESS REPORT
February 14, 2001

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.

## Planning & Determination of Resource Need

**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** |

**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

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

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

**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.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-3)

July 12, 2000

*AVISTA CORPORATION*

# 1997 Integrated Resource Plan Update

## I. Introduction:

Avista's last Integrated Resource Plan (IRP) was filed with the Commission on August 25, 1997. That plan showed that the company was surplus for many years into the future. Since then many things have changed in the electric utility industry and for Avista. Therefore, the company has prepared this updated IRP to include those significant changes. As discussed later, this updated IRP will also serve as the basis for a Request- for-Proposal (RFP) that Avista plans to issue.

The following information has been presented at various TAC meetings and will become a integral part of the next IRP.

## II. 1997 IRP Update

### 1. Load Forecast

The 2000 electric sales forecast was prepared during the summer of 1999. The forecast of firm sales to the core-market is one of the most critical elements and was presented and discussed at the TAC meeting. Avista Utilities utilizes econometric models to produce sales and customer forecasts. Econometric models are systems of algebraic equations which relate past economic growth and development in the geographic communities served electricity with past customer growth and consumption.

The electrical energy forecast shows an annual average load of 1013 aMW in 2001 increasing to 1159 aMW in 2009. The peak forecast shows 1594 MW in 2001 with 1851 MW in the year 2009. The ten-year compound growth rate for residential usage is 2.3 percent, commercial is 3.9 percent and industrial is 1.6 percent. The overall total energy forecast has a compound growth rate of 1.9 percent.

The annual load forecast numbers, for both peak and energy, through the year 2009 can be found on the Requirements and Resources tabulation sheet.

### 2. Resource Assessment

<u>Centralia</u>:
The sale of the Centralia coal-fired plant resulted in the loss of 201 MW of capacity and 177 aMW of annual energy from Avista's resource portfolio. The company entered into a short-term contract with TransAlta, the new owners of Centralia, to replace a majority of the generation lost with the sale of the plant. The term of this contract starts in July 2000 and extends through December 2003.

Hydro Relicensing:
Avista Corp. was granted by the FERC on Feb. 23, 2000, a new 45-year license to operate the Noxon Rapids and Cabinet Gorge hydroelectric projects on the lower Clark Fork River. The licensing effort culminates seven years of planning and consultation, utilizing a unique collaborative approach that produced one of the most successful ever hydro relicensing efforts. The application to relicense was submitted by Avista Corp., Feb. 18, 1999, and contained a comprehensive settlement agreement with 27 signatories.

This landmark agreement ensured the continued economical operation of the two plants while providing a variety of enhancements to natural resources of the project area. Avista retains nearly all the valuable load following and peaking capability of the two projects while providing early implementation of protection, mitigation, and enhancement measures to benefit native fish species, recreation opportunities, continued protection of cultural resources, wildlife populations, and water quality. Avista will spend approximately $4.7 million annually with a significant expenditure earmarked for enhancing bull trout populations.

Contract Sales and Purchases:
While there has been a lot of wholesale contract activity since the last report, the terms of the more recent contracts have tended to be relatively short. It is interesting to note that most of the purchase and sale agreements terminate by the year 2003, except some of the contracts with BPA and exchanges. There are only three sale contracts that extend beyond the year 2003. Those are the PacifiCorp, PGE and Snohomish PUD contracts.

> *PacifiCorp and the company entered into a ten year summer capacity sale for the period June 16, 1994 through September 15, 2003 (with PacifiCorp option to extend for up to five years). The company delivers 150 MW of summer capacity with energy purchased at 25 percent load factor based on variable prices.
>
> *Portland General Electric is purchasing from the company 150 MW of capacity through December 31, 2016. The energy associated with the capacity deliveries has to be returned within 168 hours.
>
> *Snohomish PUD purchases 100 MW of firm capacity with a minimum amount of firm energy at 50 percent load factor from the company. The contract ends September 2006.

Avista also has a large cogeneration facility (Potlatch Forest Industry) in its service territory that entered into a ten-year contract with the company which terminates at the end of 2001. The power received from Potlatch has a maximum capacity of 59 MW and average energy of 55 aMW.

Hydro Upgrades:
In 1999, the company completed the program to replace all four runners at Long Lake, which increased the capability from 72.8 MW to 88 MW. In the planning stages are turbine runner replacements and generator rewinds for three units at Cabinet Gorge and two units at Noxon Rapids. There is also a possibility of an Upper Falls turbine runner replacement and generator rewinds for three units at Little Falls.

## 3. Reserves Analysis

A reasonable level of planning reserves helps the company ensure adequate generating capacity during periods of extreme weather or unexpected plant outages. Avista's planning reserves are not based on the size or types of its resources. Avista's capacity reserves include components for cold weather, generator-forced outages and contingencies such as river freeze-up at hydroelectric plants.

The company's planning reserves are based on 10 percent increase in peak loads or one day in twenty years and an additional 90 MW to account for river freeze ups and a portion of the forced outage reserves. This provides Avista with about 15 percent reserves based on forecasted peak loads. The forecasted peak loads are based on the average expected cold day. For example, the peak for January 2000 was estimated at 1557 MW (at 8 degrees F) but we would expect the peak to be 1713 MW on the extreme day (-10 degrees F).

Avista's operating reserves are considered a part of the company's planning reserve numbers. The operating reserves are 5 percent of hydro generation and 7 percent of thermal and are what we are legally required to carry under regional criteria.

## 4. Re-dispatch Study

As the company contemplates the addition of one or more resources to its portfolio it will be faced with a different resource stack and fuel mix. The new resources will have an impact on the resource dispatch sequence because of the fuel supply and marginal costs. The company is using PROSYM to model its resources, to meet its load requirements on an hourly basis, and to assess the dispatch requirements and compatibility of new resources used in conjunction with existing resources, both hydro and thermal.

PROSYM is a commercially available production cost model used to perform electric planning and operational studies. Due to its hourly chronological design and its capability to accurately dispatch the company's flexible hydro system, we use PROSYM to perform dispatch analyses of various generation sources. A key point to remember is that PROSYM is a production cost model. The resource inputs include machine characteristics, fuel costs, and variable operation and maintenance costs. The model does not calculate the total cost of the resource. After the dispatch information is obtained from PROSYM, traditional economic analyses of each resource option must be performed.

An example of a PROSYM run with a new combined cycle combustion turbine modeled into the company's system is shown in Appendix A.

## 5. Long Term Natural Gas and Electric Price Forecasts

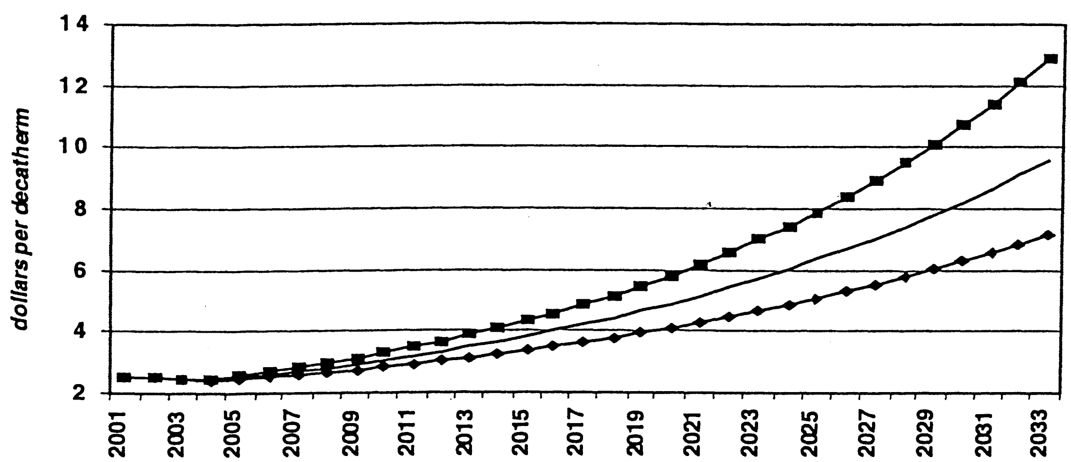
There is much uncertainty in the natural gas and electric price forecasts. Price volatility has increased recently given extremely high prices in the daily and forward markets. The company knows that there will be periods of high prices and periods of low prices as the price curves fluctuate based on demand and supply criteria. It is the company's goal to provide and use a forecast that is reasonable in its start point and escalation for the long term. Avista knows there will be variations both high and low in the future as the company forecasts these energy prices. The forecasts reflect the best information that is available at the time the forecast is made.

Key to any "buy or build" decision is an understanding of the future prices for electricity and natural gas. Because natural gas generation is a significant contributor to the cost of operating such a facility, the future prices for this underlying commodity cannot be overlooked. As discussed above, there is uncertainty in both the near-term and long-term natural gas price forecasts. Avista therefore relies on a set of forward predictions it believes account for a range of possible future outcomes.

**The Natural Gas Price Forecast**

The price forecasts developed for this update build on the natural gas forecast contained in Avista's forthcoming July, 2000 Natural Gas Integrated Resource Plan (Gas IRP). Contained in the Gas IRP is a base forecast of northwest natural gas prices, as detailed in the median or base case forecast shown below.

**Northwest Natural Gas Price Forecasts**
**2001-2033 nominal dollars**




As detailed in the graph in the base case, natural gas prices rise from an average annual value of \$2.52 in 2001 to \$6.35 per decatherm in 2025, the end of the Gas IRP forecast. On average, this equates to a 4.1 percent annual change.

The Gas IRP does not analyze natural gas price sensitivity at the wholesale level and ends its forecast in 2025. Therefore to represent low and high forecasts, the base case escalation rate was adjusted downward and upward by 1 percent annually, respectively. Additionally, to provide a 30-year forecast beginning in 2004, the rate of change in 2025 was continued through 2033. In the low case, the cost per decatherm rises only to \$7.12. In the high case, the price increases to \$12.88. This compares to a base forecast in 2033 of \$9.60 per decatherm.

## The Electricity Price Forecast

With the scenarios for future natural gas prices established, electricity price forecasts was estimated using a "spark spread." Spark spreads identify the heat rate expressed in Btu/kWh that, when applied to a natural gas price, equate an equivalent price of electricity. For example, on June 8, 2000 the forward price for July 2000 natural gas was $4.13 per decatherm. The July 2000 Mid-C forward price was approximately $110 per MWh. The spark spread for July equated to 26,635 Btu/kWh.

The average spark spread through calendar year 2000, again using quotes obtained on June 8 2000, is 21,920 Btu/kWh. Looking forward, the calendar year 2001 spark spread is approximately 17,300 Btu/kWh. To convert the natural gas price forecasts into electricity forecasts, varying spark spread values were considered. The short-term spark spreads inherent in today's forward markets appear high given historical levels. Between 1997 and 1999, the spark spread varied from a low of 7,800 to nearly 17,000 Btu/kWh.

To represent the varying spark spread levels Avista considered three spark spreads of ten, thirteen, and fifteen thousand Btu/kWh applied to the three natural gas price forecasts. At ten thousand Btu/kWh with base case gas prices, electricity prices rise from approximately $24 per MWh in 2004, to $38 per MWh in 2013, to $96 per MWh in 2033. The average annual nominal price increase equals 4.8 percent. In real terms, the equivalent values are $22, $27, and $31, equal to a 1.1 percent annual increase.

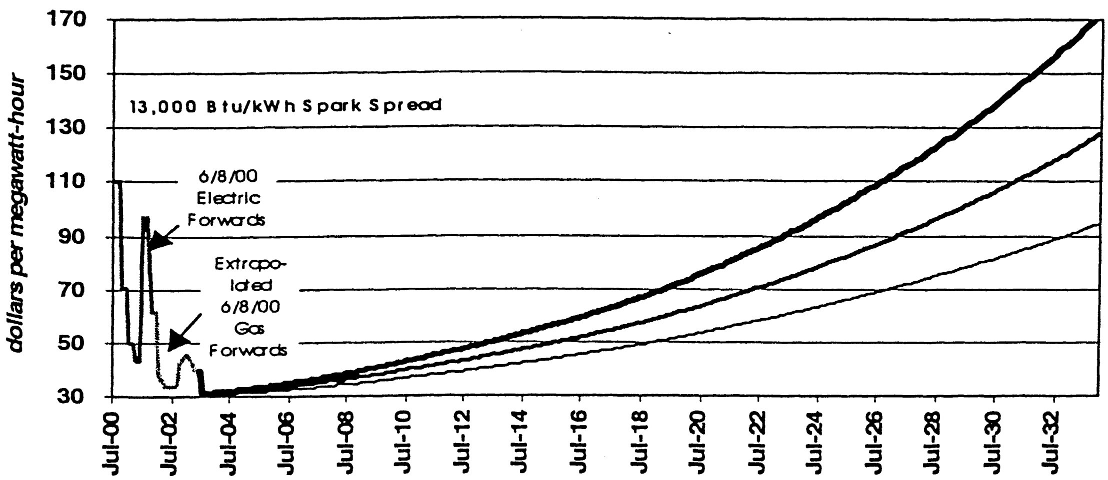
Where the spark spread is assumed to be fifteen thousand Btu/kWh, our high case estimate, electricity prices equal $39 per MWh in 2004. Prices rise to $61 in 2013 and then to $153 in 2033. The average annual price escalation again is 4.8 percent nominal. In real terms, prices rise from $36 in 2004 to $49 in 2033, for an annual average real escalation of approximately 1.1 percent.

Avista's base case spark spread forecast is thirteen thousand Btu/kWh. At this level, electricity prices rise from approximately $32 per MWh in 2004 to $50 per MWh in 2013, to $125 per MWh in 2033 using the base case gas forecast. In real terms, the equivalent values are $29, $35, and $40 per MWh in 2004, 2013, and 2033, respectively. The average nominal increase equals 4.8 percent. In real terms, the forecast rises 1.1 percent annually.

Using the low natural gas price forecast and the base case spark spread, electricity prices rise more slowly at 3.8 percent annually, or 0.1 percent real. In 2004 the annual average electricity price equals $31 per MWh. By 2033 the price equals $93 per MWh. With the high natural gas forecast, electricity prices rise at an average annual rate of 5.8 percent nominal and 2.0 percent real. Forecasted prices increase from $32 per MWh in 2004 to $167 per MWh in 2033.

The following table describes the three electricity price forecasts, including forward market prices prior to August 2003.

Northwest Electricity Price Forecasts
July 2000-2033 nominal dollars




## 6. Resource Alternatives

There are multitudes of resource options available to the company. Some are more suitable than others depending on capital cost, dispatchability, accessibility, operating experience, environmental considerations, and other impacts. All resource options will be evaluated including energy efficiency measures. Probably the preferred resource scenario will be a combination of resource options.

Some of the options that have been discussed and are under consideration are:

- Build a generating resource
- Purchase existing or new generation assets
- Complete system upgrades at generating facilities
- Negotiate a long-term power purchase agreement
- Buy in the short-term wholesale market
- Purchase the output of a generating or cogeneration facility
- Develop additional energy efficiency and DSM programs
- Buy energy efficiency through third party developers

Customer load dropping is also being considered although it is not generally considered a resource. Retail load that can be interrupted or curtailed under specific circumstances can free-up temporary capacity and energy. And as such, the company plans to explore those possibilities through contract negotiations with large customers.

The initial screening of resource costs uses data from the Power Council, actual sites being constructed or just recently constructed, and information received from national publications.

Attached are the nominal levelized costs in 1999 dollars of many supply-side resource types made available by the Power Council (see Appendix B).

Nuclear plant costs are not on the list, although we know (from previous Power Council studies) that nuclear total cost is above 100 mills/kWh or ranked on the high end of the Power Council's geothermal projects.

Biomass plants are also not on the list except for land fill gas and biogasification plants. The analysis show that biomass plants have total costs in the range of the low geothermal costs or about 70 to 80 mills /kWh.

Many of these resources have costs that are very site specific, especially the renewables like, wind and geothermal. Avista would need to do a very detailed cost analysis based on a particular site location in order to assess ultimate viability of these options.

Avista is constantly assessing the markets in order to buy and sell power on an hourly and daily basis. Most utilities and marketers don't want to commit to long-term sales due to the uncertainty in the markets. At this time other utilities in the Northwest find themselves in the same situation as Avista so a long-term commitment from them for a power supply would not be very likely. We have included in the proposed RFP a provision to bid to Avista a long-term power supply contract.

Avista's energy efficiency programs are evaluated in detail on a trimesterly basis and submitted to the company's External Energy Efficiency (Triple-E) Board for review. These reports cover the full menu of standard practice tests and descriptive statistics and are disaggregated by customer segment and technology. These reports are the basis for company program management efforts as well as providing a foundation for meaningful oversight by the Triple-E Board. The company has also assessed the potential for enhancements to specific programs to meet utility resource needs and will be assessing the potential for capacity and peak-energy targeted programs in the near future. Please see Appendix C for further information.

## 7. Screening Results

Avista has historically planned and developed various resource types. The company has experience with hydro, coal, natural gas, and biomass generating plants and demand-side resources. This operating experience gives the company valuable information that can be used in its resource evaluations.

Avista needs a resource that can provide additional benefits in support of the existing generation system. What is needed is a resource that can be dispatched, follow load, and provide a capacity component. In other words, as an entity with a control area, the company needs resources that are dispatchable and meets energy and capacity requirements under a variety of conditions.

A natural gas fired electric generation plant is one example of a resource that could meet those needs stated above. Natural gas plants can be built relatively quickly with relatively low capital costs and discharge less pollutants into the air than other fossil fuel plants. As shown in Appendix B, the Northwest Power Planning Council costs for natural gas fired generation projects range from approximately 41 mills to 43 mills.

At this point in time the following resources would not pass the initial screening. The following costs are nominal life-cycle, levelized costs.

- Nuclear: Costs are over the 100 mills per kilowatt-hour range. The total cost and the lack of public acceptance make this resource option unacceptable.
- Coal: Costs are 80 to 90 mills. The total cost and cost uncertainty in air quality issues make this resource option unacceptable.
- Wind: Costs are 60 to 80 mills. There are indications that costs are declining but our studies show there are not favorable sites in our service territory so transmission costs would have to be added. Because wind is intermittent the resource would have to be discounted for lack of capacity component. This would make this resource option unacceptable.
- Geothermal: Costs are 80 to 100 mills making this resource option unacceptable.
- Solar: Costs are over 240 mills making this resource option unacceptable.

These costs are presented for general comparison purposes. The company will solicit resource bids from the market in an upcoming Request-for-Proposals (RFP). The company is hoping for innovative bids from project developers. The RFP bids will be evaluated against the information that has been gathered both internally and externally.

## 8. Load and Resource Summary

General:
Included is Avista's annual Requirements and Resources (Load and Resource Summary) that shows the company's load and resource position on an annual basis for the next ten years (see Appendix D). It is dated June 1, 2000 and will be the same one used in the 2000 IRP. The peak column is the January peak (the highest forecasted peak for the year) and the average column is the annual 12-month average for the year. The resource peak numbers are what could be expected as maximum capacity outputs during January. The hydro peak and energy numbers are from the final regulation done by the Northwest Power Pool and reflect the reservoir levels in January per the hydro regulation study (one-year critical period, 1936-37 water). The average energy numbers are the expected 12-month averages for the loads, resources and contracts.

All the requirements are shown at the top of the page. Most of the purchases and sales contracts end by the year 2004. The peak and average forecasted loads are shown on line 1 labeled System Load. Line 17 Reserves are Avista's planning reserves and are part of the total Requirements (as described in Section 3).

The Resource section is comprised of the resources and purchase contracts. Line 19 shows the system hydro and line 20 is the contract hydro from the mid-Columbia PUD projects (with critical water conditions). The mid-Columbia numbers decrease due to the Priest Rapids contract ending in 2005 and the Wanapum contract ending in 2009. Avista is hopeful that a contract extension can be negotiated with Grant County PUD. Lines 24 and 25 are the company's existing simple-cycle combustion turbines, and lines 33 and 34 are the expected thermal generation output from Kettle Falls and Colstrip.

Line 29 shows the BPA residential exchange contract and the 47 MW flat delivery of power to the company from BPA. There is no dispatchability or flexibility with this contract. Although this contract has not been signed, Avista feels it is firm enough to be included.

Line 44 is the Surplus (Deficit) numbers calculated by subtracting the Total Requirements from the Total Resource numbers. In the year 2004 Avista is 287 MW deficit on peak and 318 aMW deficit on energy under critical water planning criteria.

Resource Flexibility:
Flexible generation resources are a key component to meet the requirements of Avista's customers. As depicted in the charts on pages 8 and 9 in Appendix E, Avista experiences load changes of 100 MW or more during several hours of each day. Loads must be ramped up and down under a variety of seasonal and load conditions. In order to meet the load, flexible resources (Cabinet Gorge, Noxon Rapids, Long Lake, Mid Columbia contract hydro, and the Rathdrum Combustion turbines) are dispatched. Even with these resources, Avista still must purchase peak energy products to meet customer demand during different times. The market today tends to offer standard heavy load hour and light load hour products that do not meet load shaping or following needs.

2004 Study:
A detailed tabulation of the load and resource requirements study of the year 2004 is also attached,(see Appendix E). We chose the year 2004 for an in-depth study because, as mentioned above, many of the larger supply and requirements contracts have ended and future requirements change (for the most part) due to load growth.

This study is shown in two parts. The first study shows on and off peak loads and resource requirements monthly under critical and normal hydro conditions. The second study goes into even further detail. We created an hourly Surplus-Deficiency duration Curve for the year 2004 using PROSYM to gain the following information. By using the Northwest Power Pool's sixty year hydro generation study for our system, PROSYM runs 720 (sixty years X 12 months/year) hydro scenarios into the forecast net system load, all known contracts, and existing resources. The information gained from this model output shows the company's resource requirements to meet load under many different hydro conditions. This duration curve will be used to analyze how new resource additions will "fit" into the company's requirements without any affect from market conditions. As stated before, standard economic modeling must be performed after dispatch information is gained from PROSYM modeling.

Load growth expectations based on the forecasted methodologies are explained under Section 1. Avista doesn't expect drastic changes in our load beyond the normal load growth that has been experienced. But the future is uncertain and Avista needs to be flexible enough to handle unforeseen changes. For example, the company could lose load by having Avista's larger retail customers install cogeneration, like WSU or Potlatch deciding to serve their own load from existing generating facilities. Or if partial deregulation was to come to our region, Avista could pick up some industrial loads thereby increasing the load requirements.

# APPENDIX A

PROSYM OUTPUT
EXISTING SYSTEM

Station Report
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| No. | Station | Energy GWh | Cap Fctr % | Sta-rts | Fuel Burn GBtu | Heat Rate Btu/kWh | Hours per Unit | FuelOrPrch ¢/MBtu <F> $/MWh <P> | Cost $000 $000 | Start Fuel GBtu | Start Cost $000 | O&M Fixed $000 | O&M Varbl $000 | Opertg Cost $/MWh | Total Cost $/MWh | Total Cost $000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | HLH PURCHASE | 685.8 | 9.1 | 107 | | | 7669 | 37.4 | 25627 | | 0 | 0 | 0 | 37.37 | 37.37 | 25627 |
| 2 | LLH PURCHASE | 694.7 | 12.3 | 54 | | | 8130 | 26.9 | 18689 | | 0 | 0 | 0 | 26.90 | 26.90 | 18689 |
| 3 | HLH Sale | -163.4 | 2.2 | 255 | | | 4940 | 30.1 | -4919 | | 0 | 0 | 0 | 30.11 | 30.11 | -4919 |
| 4 | LLH Sale | -123.4 | 2.2 | 265 | | | 5678 | 15.3 | -1892 | | 0 | 0 | 0 | 15.32 | 15.32 | -1892 |
| 5 | Spokane River | 1055.1 | 71.6 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 6 | Clark Fork Hy | 2848.3 | 42.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 7 | Mid Columbia | 994.4 | 62.9 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 8 | Colstrip 3 | 913.3 | 93.7 | 10 | | | 8228 | 6.4 | 5819 | | 0 | 0 | 2491 | 9.10 | 9.10 | 8310 |
| 9 | Colstrip 4 | 913.1 | 93.6 | 8 | | | 8226 | 6.4 | 5818 | | 0 | 0 | 2491 | 9.10 | 9.10 | 8308 |
| 10 | NortheastTurbine | 56.3 | 10.2 | 55 | 704.4 | 12500 | 1012 | 296.1 | 2086 | 0 | 0 | 0 | 282 | 42.01 | 42.01 | 2367 |
| 11 | Rathdrum 1 | 220.4 | 31.4 | 133 | 2490.3 | 11300 | 2856 | 299.5 | 7458 | 0 | 0 | 0 | 225 | 34.86 | 34.86 | 7683 |
| 12 | Rathdrum 2 | 220.4 | 31.4 | 133 | 2490.3 | 11300 | 2856 | 299.5 | 7458 | 0 | 0 | 0 | 225 | 34.86 | 34.86 | 7683 |
| 13 | Kettle Falls | 383.9 | 93.0 | 5 | | | 8169 | 9.5 | 3647 | | 15 | 0 | 902 | 11.85 | 11.89 | 4565 |
| 14 | Potlatch Cogen | 0.0 | 0.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 15 | Upriver Firm | 49.5 | 100.0 | 0 | | | 4368 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 16 | BPAexchange | 108.4 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 17 | PPLExRtn | 29.3 | 100.0 | 1 | | | 2184 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 18 | PPLExDel | -29.3 | 100.0 | 1 | | | 2184 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 19 | Entitlement | 3.6 | 40.7 | 78 | | | 961 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 20 | CSPE | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 21 | BPA Subscr | 412.8 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 22 | BPACan Ent | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 23 | WNP3 | 374.3 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 24 | Black Crk | 8.2 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 25 | BPA5yr Purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 26 | Sempra Purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 27 | Cin Purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 28 | Esi purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 29 | Enr3yr purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 30 | Enr2yr Purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 31 | Puget Sale | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 32 | PGE Capacity | -1.5 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 33 | Douglas Capacity | 0.0 | 0.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 34 | EWEB Sale | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 35 | SPUD Capacity | -629.3 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 36 | Clark Sale | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 37 | PPL94 Sale | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 38 | CEPM57 Sale | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| SYSTEM PRODUCTION | | 9025.0 | | 1105 | 5685.0 | 11436 | | | 69790 | 0 | 15 | 0 | 6616 | 8.47 | 8.47 | 76421 |

Continues...

Station Group Report
--------------------

| No. Group | Energy GWh | Cap Fctr % | Sta- rts | Fuel Burn GBtu | Heat Rate Btu/kWh | Hours per Unit | FuelOrPrch ¢/MBtu <F> $/MWh <P> | Cost $000 $000 | Start Fuel GBtu | Start Cost $000 | O&M Fixed $000 | O&M Varbl $000 | Opertg Cost $/MWh | Total Cost $/MWh | Total Cost $000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Native Load | 9021.4 | | | | | | | | | | | | | | |
| Dump Power | 0.0 | | | | | | | | | | | | | 0.00 | 0 |
| Tran. Losses | 0.0 | | | | | | | | | | | | | | |
| PS Load | 3.6 | | | | | | | | | | | | | | |
| LESS Resources (Exports): | | | | | | | | | | | | | | | |
| 1 HLH Purch | 685.8 | 9.1 | 107 | | | | 37.4 | 25627 | | 0 | 0 | 0 | 37.37 | 37.37 | 25627 |
| 2 LLH Purch | 694.7 | 12.3 | 54 | | | | 26.9 | 18689 | | 0 | 0 | 0 | 26.90 | 26.90 | 18689 |
| 3 HLH Sale | -163.4 | 2.2 | 255 | | | | 0.0 | -4919 | | 0 | 0 | 0 | 30.11 | 30.11 | -4919 |
| 4 LLH Sale | -123.4 | 2.2 | 265 | | | | 0.0 | -1892 | | 0 | 0 | 0 | 15.32 | 15.32 | -1892 |
| 5 Spokane R | 1055.1 | 71.6 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 6 Clark Fork | 2848.3 | 42.0 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 7 Mid Col | 994.4 | 62.9 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 8 Colstrip | 1826.4 | 93.7 | 17 | | | | 6.4 | 11637 | | 0 | 0 | 4982 | 9.10 | 9.10 | 16619 |
| 9 Northeast | 56.3 | 10.2 | 55 | 704.4 | 12500 | | 296.1 | 2086 | 0 | 0 | 0 | 282 | 42.01 | 42.01 | 2367 |
| 10 Rathdrum | 440.8 | 31.4 | 266 | 4980.7 | 11300 | | 299.5 | 14916 | 0 | 0 | 0 | 450 | 34.86 | 34.86 | 15365 |
| 11 Kettle Fls | 383.9 | 93.0 | 5 | | | | 9.5 | 3647 | | 15 | 0 | 902 | 11.85 | 11.89 | 4565 |
| 12 Cogen | 49.5 | 100.0 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 13 Exchange | 108.4 | 100.0 | 2 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 14 Contract Purchas | 798.9 | 99.4 | 78 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 15 Contract Sale | -630.8 | 100.0 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| [ Non-PS Resources | 9021.4 ] | | | | | | | | | | | | | | |
| [ PS Generation | 3.6 ] | | | | | | | | | | | | | | |
| Resource Totals | 9025.0 | | 1105 | 5685.0 | 11436 | | | 69790 | 0 | 15 | 0 | 6616 | 8.47 | 8.47 | 76421 |
| E.N.S. | 0.0 | | | | | | | | | | | | | 100.00 | 0 |
| SYSTEM | | | | | | | | | | | | | | 8.47 | 76421 |

Spinning reserve deficit report
-------------------------------

| Type | No. | Deficit area | Hrs | -Spinning reserve- Energy MW | Cost $000 | Hrs | -Primary reserve- Energy MW | Cost $000 |
|---|---|---|---|---|---|---|---|---|
| Syst | 0 | System | 627 | 23788 | 0 | 319 | 9380 | 0 |

Emission Report
---------------

| No. Station | NOx (1000tn) | Emiss 7 (1000tn) | Emiss 8 (1000tn) |
|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 1 | HLH PURCHASE | 0.000 | 0.000 | 0.000 |

Continues...

Continues...

| No. | Station | NOx (1000tn) | Emiss 7 (1000tn) | Emiss 8 (1000tn) |
|---|---|---|---|---|
| 2 | LLH PURCHASE | 0.000 | 0.000 | 0.000 |
| 3 | HLH Sale | 0.000 | 0.000 | 0.000 |
| 4 | LLH Sale | 0.000 | 0.000 | 0.000 |
| 5 | Spokane River | 0.000 | 0.000 | 0.000 |
| 6 | Clark Fork Hy | 0.000 | 0.000 | 0.000 |
| 7 | Mid Columbia | 0.000 | 0.000 | 0.000 |
| 8 | Colstrip 3 | 0.000 | 0.000 | 0.000 |
| 9 | Colstrip 4 | 0.000 | 0.000 | 0.000 |
| 10 | NortheastTurbine | 0.148 | 0.000 | 0.000 |
| 11 | Rathdrum 1 | 0.074 | 0.010 | 0.076 |
| 12 | Rathdrum 2 | 0.074 | 0.010 | 0.076 |
| 13 | Kettle Falls | 0.000 | 0.000 | 0.000 |
| 14 | Potlatch Cogen | 0.000 | 0.000 | 0.000 |
| 15 | Upriver Firm | 0.000 | 0.000 | 0.000 |
| 16 | BPAexchange | 0.000 | 0.000 | 0.000 |
| 17 | PPLExRtn | 0.000 | 0.000 | 0.000 |
| 18 | PPLExDel | 0.000 | 0.000 | 0.000 |
| 19 | Entitlement | 0.000 | 0.000 | 0.000 |
| 20 | CSPE | 0.000 | 0.000 | 0.000 |
| 21 | BPA Subscr | 0.000 | 0.000 | 0.000 |
| 22 | BPACan Ent | 0.000 | 0.000 | 0.000 |
| 23 | WNP3 | 0.000 | 0.000 | 0.000 |
| 24 | Black Crk | 0.000 | 0.000 | 0.000 |
| 25 | BPA5yr Purchase | 0.000 | 0.000 | 0.000 |
| 26 | Sempra Purchase | 0.000 | 0.000 | 0.000 |
| 27 | Cin Purchase | 0.000 | 0.000 | 0.000 |
| 28 | Esi purchase | 0.000 | 0.000 | 0.000 |
| 29 | Enr3yr purchase | 0.000 | 0.000 | 0.000 |
| 30 | Enr2yr Purchase | 0.000 | 0.000 | 0.000 |
| 31 | Puget Sale | 0.000 | 0.000 | 0.000 |
| 32 | PGE Capacity | 0.000 | 0.000 | 0.000 |
| 33 | Douglas Capacity | 0.000 | 0.000 | 0.000 |
| 34 | EWEB Sale | 0.000 | 0.000 | 0.000 |
| 35 | SPUD Capacity | 0.000 | 0.000 | 0.000 |
| 36 | Clark Sale | 0.000 | 0.000 | 0.000 |
| 37 | PPL94 Sale | 0.000 | 0.000 | 0.000 |
| 38 | CEPM57 Sale | 0.000 | 0.000 | 0.000 |
| SYSTEM EMISSIONS | | 0.30 | 0.02 | 0.15 |

| No. | Station | NOx (1000tn) | Emiss 7 (1000tn) | Emiss 8 (1000tn) |
|---|---|---|---|---|
| 1 | HLH PURCHASE | 0.000 | 0.000 | 0.000 |
| 2 | LLH PURCHASE | 0.000 | 0.000 | 0.000 |
| 3 | HLH Sale | 0.000 | 0.000 | 0.000 |
| 4 | LLH Sale | 0.000 | 0.000 | 0.000 |
| 5 | Spokane River | 0.000 | 0.000 | 0.000 |
| 6 | Clark Fork Hy | 0.000 | 0.000 | 0.000 |
| 7 | Mid Columbia | 0.000 | 0.000 | 0.000 |
| 8 | Colstrip 3 | 0.000 | 0.000 | 0.000 |
| 9 | Colstrip 4 | 0.000 | 0.000 | 0.000 |

| No. | Station | NOx (1000tn) | Emiss 7 (1000tn) | Emiss 8 (1000tn) |
|---|---|---|---|---|
| 10 | NortheastTurbine | 0.148 | 0.000 | 0.000 |
| | SumasRock Gas | 0.148 | 0.000 | 0.000 |
| 11 | Rathdrum 1 | 0.074 | 0.010 | 0.076 |
| | Rathdrum Gas | 0.074 | 0.010 | 0.076 |
| 12 | Rathdrum 2 | 0.074 | 0.010 | 0.076 |
| | Rathdrum Gas | 0.074 | 0.010 | 0.076 |
| 13 | Kettle Falls | 0.000 | 0.000 | 0.000 |
| 14 | Potlatch Cogen | 0.000 | 0.000 | 0.000 |
| 15 | Upriver Firm | 0.000 | 0.000 | 0.000 |
| 16 | BPAexchange | 0.000 | 0.000 | 0.000 |
| 17 | PPLExRtn | 0.000 | 0.000 | 0.000 |
| 18 | PPLExDel | 0.000 | 0.000 | 0.000 |
| 19 | Entitlement | 0.000 | 0.000 | 0.000 |
| 20 | CSPE | 0.000 | 0.000 | 0.000 |
| 21 | BPA Subscr | 0.000 | 0.000 | 0.000 |
| 22 | BPACan Ent | 0.000 | 0.000 | 0.000 |
| 23 | WNP3 | 0.000 | 0.000 | 0.000 |
| 24 | Black Crk | 0.000 | 0.000 | 0.000 |
| 25 | BPA5yr Purchase | 0.000 | 0.000 | 0.000 |
| 26 | Sempra Purchase | 0.000 | 0.000 | 0.000 |
| 27 | Cin Purchase | 0.000 | 0.000 | 0.000 |
| 28 | Esi purchase | 0.000 | 0.000 | 0.000 |
| 29 | Enr3yr purchase | 0.000 | 0.000 | 0.000 |
| 30 | Enr2yr Purchase | 0.000 | 0.000 | 0.000 |
| 31 | Puget Sale | 0.000 | 0.000 | 0.000 |
| 32 | PGE Capacity | 0.000 | 0.000 | 0.000 |
| 33 | Douglas Capacity | 0.000 | 0.000 | 0.000 |
| 34 | EWEB Sale | 0.000 | 0.000 | 0.000 |
| 35 | SPUD Capacity | 0.000 | 0.000 | 0.000 |
| 36 | Clark Sale | 0.000 | 0.000 | 0.000 |
| 37 | PPL94 Sale | 0.000 | 0.000 | 0.000 |
| 38 | CEPM57 Sale | 0.000 | 0.000 | 0.000 |
| SYSTEM EMISSIONS | | 0.30 | 0.02 | 0.15 |

| No. | Group | NOx (1000tn) | Emiss 7 (1000tn) | Emiss 8 (1000tn) |
|---|---|---|---|---|
| 1 | HLH Purch | 0.000 | 0.000 | 0.000 |
| 2 | LLH Purch | 0.000 | 0.000 | 0.000 |
| 3 | HLH Sale | 0.000 | 0.000 | 0.000 |
| 4 | LLH Sale | 0.000 | 0.000 | 0.000 |
| 5 | Spokane R | 0.000 | 0.000 | 0.000 |
| 6 | Clark Fork | 0.000 | 0.000 | 0.000 |
| 7 | Mid Col | 0.000 | 0.000 | 0.000 |
| 8 | Colstrip | 0.000 | 0.000 | 0.000 |
| 9 | Northeast | 0.148 | 0.000 | 0.000 |
| 10 | Rathdrum | 0.149 | 0.020 | 0.151 |
| 11 | Kettle Fls | 0.000 | 0.000 | 0.000 |
| 12 | Cogen | 0.000 | 0.000 | 0.000 |
| 13 | Exchange | 0.000 | 0.000 | 0.000 |
| 14 | Contract Purchas | 0.000 | 0.000 | 0.000 |
| 15 | Contract Sale | 0.000 | 0.000 | 0.000 |
| SYSTEM EMISSIONS | | 0.30 | 0.02 | 0.15 |

Time of Day Marginal Cost Summary

| Period | Total hours | % of hours | Average Marg Cost |
|---|---|---|---|
| 1 On Peak | 5024 | 57.2 | 37.22 |
| 2 Off Peak | 3760 | 42.8 | 25.32 |
| Total | 8784 | 100.0 | 32.12 |

Percent Time at Margin, by Station Group

| Groups | Time of Day Periods 1 | 2 | All |
|---|---|---|---|
| 1 HLH Purch | 76.5 | 0.0 | 43.8 |
| 2 LLH Purch | 0.0 | 82.6 | 35.4 |
| 3 HLH Sale | 23.5 | 0.0 | 13.4 |
| 4 LLH Sale | 0.0 | 17.4 | 7.4 |
| 5 Spokane R | 0.0 | 0.0 | 0.0 |
| 6 Clark Fork | 0.0 | 0.0 | 0.0 |
| 7 Mid Col | 0.0 | 0.0 | 0.0 |
| 8 Colstrip | 0.0 | 0.0 | 0.0 |
| 9 Northeast | 0.0 | 0.0 | 0.0 |
| 10 Rathdrum | 0.0 | 0.0 | 0.0 |
| 11 Kettle Fls | 0.0 | 0.0 | 0.0 |
| 12 Cogen | 0.0 | 0.0 | 0.0 |
| 13 Exchange | 0.0 | 0.0 | 0.0 |

| | | | |
|---|---|---|---|
| 14 Contract Purchas | 0.0 | 0.0 | 0.0 |

Continues...

| Groups | Time of Day Periods 1 | 2 | All |
|---|---|---|---|
| 15 Contract Sale | 0.0 | 0.0 | 0.0 |
| Dump Power | 0.0 | 0.0 | 0.0 |
| E.N.S. | 0.0 | 0.0 | 0.0 |

## Cost at Margin, by Period and Station Group (mills)

| Groups | Time of Day Periods 1 | 2 | All |
|---|---|---|---|
| 1 HLH Purch | 38.6 | 0.0 | 38.6 |
| 2 LLH Purch | 0.0 | 27.3 | 27.3 |
| 3 HLH Sale | 32.7 | 0.0 | 32.7 |
| 4 LLH Sale | 0.0 | 15.8 | 15.8 |
| 5 Spokane R | 0.0 | 0.0 | 0.0 |
| 6 Clark Fork | 0.0 | 0.0 | 0.0 |
| 7 Mid Col | 0.0 | 0.0 | 0.0 |
| 8 Colstrip | 0.0 | 0.0 | 0.0 |
| 9 Northeast | 0.0 | 0.0 | 0.0 |
| 10 Rathdrum | 0.0 | 0.0 | 0.0 |
| 11 Kettle Fls | 0.0 | 0.0 | 0.0 |
| 12 Cogen | 0.0 | 0.0 | 0.0 |
| 13 Exchange | 0.0 | 0.0 | 0.0 |
| 14 Contract Purchas | 0.0 | 0.0 | 0.0 |
| 15 Contract Sale | 0.0 | 0.0 | 0.0 |
| Dump Power | 0.0 | 0.0 | 0.0 |
| E.N.S. | 0.0 | 0.0 | 0.0 |

## Average Hourly Cost Summary

| Period | Total hours | % of hours | Total GWh | Average cost |
|---|---|---|---|---|
| 1 On Peak | 5024 | 57.2 | 5613 | 8.74 |
| 2 Off Peak | 3760 | 42.8 | 3409 | 8.03 |
| Total | 8784 | 100.0 | 9021 | 8.47 |

## Fuel Use Report

| No. Fuel | GBtu used | Commod $000 | Volume1 $000 | Volume2 $000 | Demand $000 | Total $000 | ¢/MBtu average |
|---|---|---|---|---|---|---|---|
| 1 Kingsgate Gas | 0.0 | 0 | 0 | 0 | 0 | 0.00 | 0.0 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 2 | Rathdrum Gas | 4980.7 | 13571 | 1345 | 0 | 0 | 14915.70 | 299.5 |
| 3 | SumasRock Gas | 704.4 | 1855 | 229 | 1 | 0 | 2085.58 | 296.1 |

Continues...

Station Fuel Report (GBtu used)

| No. | Station | SumasRock Gas | Rathdrum Gas |
|---|---|---|---|
| 10 | NortheastTurbine | 704.4 | - |
| 11 | Rathdrum 1 | - | 2490.3 |
| 12 | Rathdrum 2 | - | 2490.3 |

Plant Fuel Report (GBtu used)

| No. | Plant | SumasRock Gas | Rathdrum Gas |
|---|---|---|---|

| No. | Station | Max Cap MW | Hours | Fuel | Energy GWh | Fuel GBtu | Fuel Units | Cost $000 | Price ¢/MBtu |
|---|---|---|---|---|---|---|---|---|---|
| 10 | NortheastTurbine | 69.0 | 1012 | SumasRock Gas | 56.3 | 704.4 | | 2085.6 | 296.10 |
| 11 | Rathdrum 1 | 88.0 | 2856 | Rathdrum Gas | 220.4 | 2490.3 | | 7457.9 | 299.47 |
| 12 | Rathdrum 2 | 88.0 | 2856 | Rathdrum Gas | 220.4 | 2490.3 | | 7457.9 | 299.47 |

PROSYM OUTPUT
ADD CCCT AT RATHDRUM
BY EXAMPLE

Station Report

| No. | Station | Energy GWh | Cap Fctr % | Sta-rts | Fuel Burn GBtu | Heat Rate Btu/kWh | Hours per Unit | FuelOrPrch ¢/MBtu <F> $/MWh <P> | Cost $000 $000 | Start Fuel GBtu | Start Cost $000 | O&M Fixed $000 | O&M Varbl $000 | Opertg Cost $/MWh | Total Cost $/MWh | Total Cost $000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | HLH PURCHASE | 109.4 | 1.5 | 264 | | | 4867 | 35.5 | 3879 | | 0 | 0 | 0 | 35.47 | 35.47 | 3879 |
| 2 | LLH PURCHASE | 241.4 | 4.3 | 221 | | | 6562 | 25.8 | 6220 | | 0 | 0 | 0 | 25.77 | 25.77 | 6220 |
| 3 | HLH Sale | -695.3 | 9.2 | 109 | | | 7680 | 35.0 | -24328 | | 0 | 0 | 0 | 34.99 | 34.99 | -24328 |
| 4 | LLH Sale | -285.0 | 5.1 | 208 | | | 7246 | 22.4 | -6384 | | 0 | 0 | 0 | 22.41 | 22.41 | -6384 |
| 5 | Spokane River | 1055.1 | 71.6 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 6 | Clark Fork Hy | 2848.3 | 42.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 7 | Mid Columbia | 994.4 | 62.9 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 8 | Colstrip 3 | 913.3 | 93.7 | 10 | | | 8228 | 6.4 | 5819 | | 0 | 0 | 2491 | 9.10 | 9.10 | 8310 |
| 9 | Colstrip 4 | 913.1 | 93.6 | 8 | | | 8226 | 6.4 | 5818 | | 0 | 0 | 2491 | 9.10 | 9.10 | 8308 |
| 10 | NortheastTurbine | 56.3 | 10.2 | 55 | 704.4 | 12500 | 1012 | 296.1 | 2086 | 0 | 0 | 0 | 282 | 42.01 | 42.01 | 2367 |
| 11 | Rathdrum 1 | 220.4 | 31.4 | 133 | 2490.3 | 11300 | 2856 | 299.5 | 7458 | 0 | 0 | 0 | 225 | 34.86 | 34.86 | 7683 |
| 12 | Rathdrum 2 | 220.4 | 31.4 | 133 | 2490.3 | 11300 | 2856 | 299.5 | 7458 | 0 | 0 | 0 | 225 | 34.86 | 34.86 | 7683 |
| 13 | RCCCT | 1724.0 | 85.2 | 68 | 13294.9 | 7712 | 7481 | 275.4 | 36611 | 0 | 0 | 0 | 1759 | 22.26 | 22.26 | 38370 |
| 14 | Kettle Falls | 383.1 | 92.8 | 9 | | | 8152 | 9.5 | 3640 | | 26 | 0 | 900 | 11.85 | 11.92 | 4567 |
| 15 | Potlatch Cogen | 0.0 | 0.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 16 | Upriver Firm | 49.5 | 100.0 | 0 | | | 4368 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 17 | BPAexchange | 108.4 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 18 | PPLExRtn | 29.3 | 100.0 | 1 | | | 2184 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 19 | PPLExDel | -29.3 | 100.0 | 1 | | | 2184 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 20 | Entitlement | 3.6 | 41.7 | 84 | | | 989 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 21 | CSPE | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 22 | BPA Subscr | 412.8 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 23 | BPACan Ent | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 24 | WNP3 | 374.3 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 25 | Black Crk | 8.2 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 26 | BPA5yr Purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 27 | Sempra Purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 28 | Cin Purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 29 | Esi purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 30 | Enr3yr purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 31 | Enr2yr Purchase | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 32 | Puget Sale | 0.0 | 0.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 33 | PGE Capacity | -1.5 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 34 | Douglas Capacity | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 35 | EWEB Sale | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 36 | SPUD Capacity | -629.3 | 100.0 | 0 | | | 8784 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 37 | Clark Sale | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 38 | PPL94 Sale | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 39 | CEPM57 Sale | 0.0 | 0.0 | 0 | | | 0 | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| SYSTEM PRODUCTION | | 9025.1 | | 1304 | 18979.9 | 8545 | | | 48276 | 0 | 26 | 0 | 8372 | 6.28 | 6.28 | 56675 |

Continues...

Station Group Report

| No. Group | Energy GWh | Cap Fctr % | Sta-rts | Fuel Burn GBtu | Heat Rate Btu/kWh | Hours per Unit | FuelOrPrch ¢/MBtu <F> $/MWh <P> | Cost $000 $000 | Start Fuel GBtu | Start Cost $000 | O&M Fixed $000 | O&M Varbl $000 | Opertg Cost $/MWh | Total Cost $/MWh | Total Cost $000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Native Load | 9021.4 | | | | | | | | | | | | | | |
| Dump Power | 0.0 | | | | | | | | | | | | | 0.00 | 0 |
| Tran. Losses | 0.0 | | | | | | | | | | | | | | |
| PS Load | 3.6 | | | | | | | | | | | | | | |
| LESS Resources (Exports): | | | | | | | | | | | | | | | |
| 1 HLH Purch | 109.4 | 1.5 | 264 | | | | 35.5 | 3879 | | 0 | 0 | 0 | 35.47 | 35.47 | 3879 |
| 2 LLH Purch | 241.4 | 4.3 | 221 | | | | 25.8 | 6220 | | 0 | 0 | 0 | 25.77 | 25.77 | 6220 |
| 3 HLH Sale | -695.3 | 9.2 | 109 | | | | 0.0 | -24328 | | 0 | 0 | 0 | 34.99 | 34.99 | -24328 |
| 4 LLH Sale | -285.0 | 5.1 | 208 | | | | 0.0 | -6384 | | 0 | 0 | 0 | 22.41 | 22.41 | -6384 |
| 5 Spokane R | 1055.1 | 71.6 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 6 Clark Fork | 2848.3 | 42.0 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 7 Mid Col | 994.4 | 62.9 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 8 Colstrip | 1826.4 | 93.7 | 17 | | | | 6.4 | 11637 | | 0 | 0 | 4982 | 9.10 | 9.10 | 16619 |
| 9 Northeast | 56.3 | 10.2 | 55 | 704.4 | 12500 | | 296.1 | 2086 | 0 | 0 | 0 | 282 | 42.01 | 42.01 | 2367 |
| 10 Rathdrum | 440.8 | 31.4 | 266 | 4980.7 | 11300 | | 299.5 | 14916 | 0 | 0 | 0 | 450 | 34.86 | 34.86 | 15365 |
| 11 RathdrumCCCT | 1724.0 | 85.2 | 68 | 13294.9 | 7712 | | 275.4 | 36611 | 0 | 0 | 0 | 1759 | 22.26 | 22.26 | 38370 |
| 12 Kettle Fls | 383.1 | 92.8 | 9 | | | | 9.5 | 3640 | | 26 | 0 | 900 | 11.85 | 11.92 | 4567 |
| 13 Cogen | 49.5 | 100.0 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 14 Exchange | 108.4 | 100.0 | 2 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 15 Contract Purchas | 799.0 | 99.4 | 84 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| 16 Contract Sale | -630.8 | 100.0 | 0 | | | | 0.0 | 0 | | 0 | 0 | 0 | 0.00 | 0.00 | 0 |
| [ Non-PS Resources | 9021.4 ] | | | | | | | | | | | | | | |
| [ PS Generation | 3.6 ] | | | | | | | | | | | | | | |
| Resource Totals | 9025.1 | | 1304 | 18979.9 | 8545 | | | 48276 | 0 | 26 | 0 | 8372 | 6.28 | 6.28 | 56675 |
| E.N.S. | 0.0 | | | | | | | | | | | | | 100.00 | 0 |
| SYSTEM | | | | | | | | | | | | | | 6.28 | 56675 |

Spinning reserve deficit report

| Type | No. | Deficit area | Hrs | -Spinning reserve- Energy MW | Cost $000 | Hrs | -Primary reserve- Energy MW | Cost $000 |
|---|---|---|---|---|---|---|---|---|
| Syst | 0 | System | 744 | 31057 | 0 | 436 | 12879 | 0 |

Continues...

## Emission Report

| No. | Station | NOx (1000tn) | Emiss 7 (1000tn) | Emiss 8 (1000tn) |
|---|---|---|---|---|
| 1 | HLH PURCHASE | 0.000 | 0.000 | 0.000 |
| 2 | LLH PURCHASE | 0.000 | 0.000 | 0.000 |
| 3 | HLH Sale | 0.000 | 0.000 | 0.000 |
| 4 | LLH Sale | 0.000 | 0.000 | 0.000 |
| 5 | Spokane River | 0.000 | 0.000 | 0.000 |
| 6 | Clark Fork Hy | 0.000 | 0.000 | 0.000 |
| 7 | Mid Columbia | 0.000 | 0.000 | 0.000 |
| 8 | Colstrip 3 | 0.000 | 0.000 | 0.000 |
| 9 | Colstrip 4 | 0.000 | 0.000 | 0.000 |
| 10 | NortheastTurbine | 0.148 | 0.000 | 0.000 |
| 11 | Rathdrum 1 | 0.074 | 0.010 | 0.076 |
| 12 | Rathdrum 2 | 0.074 | 0.010 | 0.076 |
| 13 | RCCCT | 0.195 | 0.026 | 0.198 |
| 14 | Kettle Falls | 0.000 | 0.000 | 0.000 |
| 15 | Potlatch Cogen | 0.000 | 0.000 | 0.000 |
| 16 | Upriver Firm | 0.000 | 0.000 | 0.000 |
| 17 | BPAexchange | 0.000 | 0.000 | 0.000 |
| 18 | PPLExRtn | 0.000 | 0.000 | 0.000 |
| 19 | PPLExDel | 0.000 | 0.000 | 0.000 |
| 20 | Entitlement | 0.000 | 0.000 | 0.000 |
| 21 | CSPE | 0.000 | 0.000 | 0.000 |
| 22 | BPA Subscr | 0.000 | 0.000 | 0.000 |
| 23 | BPACan Ent | 0.000 | 0.000 | 0.000 |
| 24 | WNP3 | 0.000 | 0.000 | 0.000 |
| 25 | Black Crk | 0.000 | 0.000 | 0.000 |
| 26 | BPA5yr Purchase | 0.000 | 0.000 | 0.000 |
| 27 | Sempra Purchase | 0.000 | 0.000 | 0.000 |
| 28 | Cin Purchase | 0.000 | 0.000 | 0.000 |
| 29 | Esi purchase | 0.000 | 0.000 | 0.000 |
| 30 | Enr3yr purchase | 0.000 | 0.000 | 0.000 |
| 31 | Enr2yr Purchase | 0.000 | 0.000 | 0.000 |
| 32 | Puget Sale | 0.000 | 0.000 | 0.000 |
| 33 | PGE Capacity | 0.000 | 0.000 | 0.000 |
| 34 | Douglas Capacity | 0.000 | 0.000 | 0.000 |
| 35 | EWEB Sale | 0.000 | 0.000 | 0.000 |
| 36 | SPUD Capacity | 0.000 | 0.000 | 0.000 |
| 37 | Clark Sale | 0.000 | 0.000 | 0.000 |
| 38 | PPL94 Sale | 0.000 | 0.000 | 0.000 |
| 39 | CEPM57 Sale | 0.000 | 0.000 | 0.000 |
| SYSTEM EMISSIONS | | 0.49 | 0.05 | 0.35 |

| No. | Station | NOx (1000tn) | Emiss 7 (1000tn) | Emiss 8 (1000tn) |
|---|---|---|---|---|
| 1 | HLH PURCHASE | 0.000 | 0.000 | 0.000 |
| 2 | LLH PURCHASE | 0.000 | 0.000 | 0.000 |

Continues...

| No. | Station | NOx (1000tn) | Emiss 7 (1000tn) | Emiss 8 (1000tn) |
|---|---|---|---|---|
| 3 | HLH Sale | 0.000 | 0.000 | 0.000 |
| 4 | LLH Sale | 0.000 | 0.000 | 0.000 |
| 5 | Spokane River | 0.000 | 0.000 | 0.000 |
| 6 | Clark Fork Hy | 0.000 | 0.000 | 0.000 |
| 7 | Mid Columbia | 0.000 | 0.000 | 0.000 |
| 8 | Colstrip 3 | 0.000 | 0.000 | 0.000 |
| 9 | Colstrip 4 | 0.000 | 0.000 | 0.000 |
| 10 | NortheastTurbine | 0.148 | 0.000 | 0.000 |
| | SumasRock Gas | 0.148 | 0.000 | 0.000 |
| 11 | Rathdrum 1 | 0.074 | 0.010 | 0.076 |
| | Rathdrum Gas | 0.074 | 0.010 | 0.076 |
| 12 | Rathdrum 2 | 0.074 | 0.010 | 0.076 |
| | Rathdrum Gas | 0.074 | 0.010 | 0.076 |
| 13 | RCCCT | 0.195 | 0.026 | 0.198 |
| | Kingsgate Gas | 0.195 | 0.026 | 0.198 |
| 14 | Kettle Falls | 0.000 | 0.000 | 0.000 |
| 15 | Potlatch Cogen | 0.000 | 0.000 | 0.000 |
| 16 | Upriver Firm | 0.000 | 0.000 | 0.000 |
| 17 | BPAexchange | 0.000 | 0.000 | 0.000 |
| 18 | PPLExRtn | 0.000 | 0.000 | 0.000 |
| 19 | PPLExDel | 0.000 | 0.000 | 0.000 |
| 20 | Entitlement | 0.000 | 0.000 | 0.000 |
| 21 | CSPE | 0.000 | 0.000 | 0.000 |
| 22 | BPA Subscr | 0.000 | 0.000 | 0.000 |
| 23 | BPACan Ent | 0.000 | 0.000 | 0.000 |
| 24 | WNP3 | 0.000 | 0.000 | 0.000 |
| 25 | Black Crk | 0.000 | 0.000 | 0.000 |
| 26 | BPA5yr Purchase | 0.000 | 0.000 | 0.000 |
| 27 | Sempra Purchase | 0.000 | 0.000 | 0.000 |
| 28 | Cin Purchase | 0.000 | 0.000 | 0.000 |
| 29 | Esi purchase | 0.000 | 0.000 | 0.000 |
| 30 | Enr3yr purchase | 0.000 | 0.000 | 0.000 |
| 31 | Enr2yr Purchase | 0.000 | 0.000 | 0.000 |
| 32 | Puget Sale | 0.000 | 0.000 | 0.000 |
| 33 | PGE Capacity | 0.000 | 0.000 | 0.000 |
| 34 | Douglas Capacity | 0.000 | 0.000 | 0.000 |
| 35 | EWEB Sale | 0.000 | 0.000 | 0.000 |
| 36 | SPUD Capacity | 0.000 | 0.000 | 0.000 |
| 37 | Clark Sale | 0.000 | 0.000 | 0.000 |
| 38 | PPL94 Sale | 0.000 | 0.000 | 0.000 |
| 39 | CEPM57 Sale | 0.000 | 0.000 | 0.000 |
| SYSTEM EMISSIONS | | 0.49 | 0.05 | 0.35 |

| No. | Group | NOx (1000tn) | Emiss 7 (1000tn) | Emiss 8 (1000tn) |
|---|---|---|---|---|
| 1 | HLH Purch | 0.000 | 0.000 | 0.000 |
| 2 | LLH Purch | 0.000 | 0.000 | 0.000 |
| 3 | HLH Sale | 0.000 | 0.000 | 0.000 |
| 4 | LLH Sale | 0.000 | 0.000 | 0.000 |
| 5 | Spokane R | 0.000 | 0.000 | 0.000 |
| 6 | Clark Fork | 0.000 | 0.000 | 0.000 |
| 7 | Mid Col | 0.000 | 0.000 | 0.000 |
| 8 | Colstrip | 0.000 | 0.000 | 0.000 |
| 9 | Northeast | 0.148 | 0.000 | 0.000 |
| 10 | Rathdrum | 0.149 | 0.020 | 0.151 |
| 11 | RathdrumCCCT | 0.195 | 0.026 | 0.198 |
| 12 | Kettle Fls | 0.000 | 0.000 | 0.000 |
| 13 | Cogen | 0.000 | 0.000 | 0.000 |
| 14 | Exchange | 0.000 | 0.000 | 0.000 |
| 15 | Contract Purchas | 0.000 | 0.000 | 0.000 |
| 16 | Contract Sale | 0.000 | 0.000 | 0.000 |
| SYSTEM EMISSIONS | | 0.49 | 0.05 | 0.35 |

## Time of Day Marginal Cost Summary

| Period | Total hours | % of hours | Average Marg Cost |
|---|---|---|---|
| 1 On Peak | 5024 | 57.2 | 37.21 |
| 2 Off Peak | 3760 | 42.8 | 25.31 |
| Total | 8784 | 100.0 | 32.12 |

## Percent Time at Margin, by Station Group

| Groups | Time of Day Periods 1 | 2 | All |
|---|---|---|---|
| 1 HLH Purch | 22.0 | 0.0 | 12.6 |
| 2 LLH Purch | 0.0 | 40.9 | 17.5 |
| 3 HLH Sale | 78.0 | 0.0 | 44.6 |
| 4 LLH Sale | 0.0 | 59.1 | 25.3 |
| 5 Spokane R | 0.0 | 0.0 | 0.0 |
| 6 Clark Fork | 0.0 | 0.0 | 0.0 |
| 7 Mid Col | 0.0 | 0.0 | 0.0 |
| 8 Colstrip | 0.0 | 0.0 | 0.0 |
| 9 Northeast | 0.0 | 0.0 | 0.0 |
| 10 Rathdrum | 0.0 | 0.0 | 0.0 |
| 11 RathdrumCCCT | 0.0 | 0.0 | 0.0 |
| 12 Kettle Fls | 0.0 | 0.0 | 0.0 |

| | | | |
|---|---|---|---|
| 13 Cogen | 0.0 | 0.0 | 0.0 |

Continues...

| Groups | Time of Day Periods 1 | 2 | All |
|---|---|---|---|
| 14 Exchange | 0.0 | 0.0 | 0.0 |
| 15 Contract Purchas | 0.0 | 0.0 | 0.0 |
| 16 Contract Sale | 0.0 | 0.0 | 0.0 |
| Dump Power | 0.0 | 0.0 | 0.0 |
| E.N.S. | 0.0 | 0.0 | 0.0 |

Cost at Margin, by Period and Station Group (mills)

| Groups | Time of Day Periods 1 | 2 | All |
|---|---|---|---|
| 1 HLH Purch | 35.0 | 0.0 | 35.0 |
| 2 LLH Purch | 0.0 | 26.5 | 26.5 |
| 3 HLH Sale | 37.8 | 0.0 | 37.8 |
| 4 LLH Sale | 0.0 | 24.5 | 24.5 |
| 5 Spokane R | 0.0 | 0.0 | 0.0 |
| 6 Clark Fork | 0.0 | 0.0 | 0.0 |
| 7 Mid Col | 0.0 | 0.0 | 0.0 |
| 8 Colstrip | 0.0 | 0.0 | 0.0 |
| 9 Northeast | 0.0 | 0.0 | 0.0 |
| 10 Rathdrum | 0.0 | 0.0 | 0.0 |
| 11 RathdrumCCCT | 0.0 | 0.0 | 0.0 |
| 12 Kettle Fls | 0.0 | 0.0 | 0.0 |
| 13 Cogen | 0.0 | 0.0 | 0.0 |
| 14 Exchange | 0.0 | 0.0 | 0.0 |
| 15 Contract Purchas | 0.0 | 0.0 | 0.0 |
| 16 Contract Sale | 0.0 | 0.0 | 0.0 |
| Dump Power | 0.0 | 0.0 | 0.0 |
| E.N.S. | 0.0 | 0.0 | 0.0 |

Average Hourly Cost Summary

| Period | Total hours | % of hours | Total GWh | Average cost |
|---|---|---|---|---|
| 1 On Peak | 5024 | 57.2 | 5613 | 5.81 |
| 2 Off Peak | 3760 | 42.8 | 3409 | 7.06 |
| Total | 8784 | 100.0 | 9021 | 6.28 |

Fuel Use Report

| GBtu | Commod | Volume1 | Volume2 | Demand | Total | ¢/MBtu |
|---|---|---|---|---|---|---|

| No. | Fuel | used | $000 | $000 | $000 | $000 | $000 | average |
|---|---|---|---|---|---|---|---|---|
| 1 | Kingsgate Gas | 13294.9 | 36611 | 0 | 0 | 0 | 36611.10 | 275.4 |
| 2 | Rathdrum Gas | 4980.7 | 13571 | 1345 | 0 | 0 | 14915.70 | 299.5 |

Continues...

| No. | Fuel | GBtu used | Commod $000 | Volume1 $000 | Volume2 $000 | Demand $000 | Total $000 | ¢/MBtu average |
|---|---|---|---|---|---|---|---|---|
| 3 | SumasRock Gas | 704.4 | 1855 | 229 | 1 | 0 | 2085.58 | 296.1 |

Station Fuel Report (GBtu used)

| No. | Station | SumasRock Gas | Rathdrum Gas | Kingsgate Gas |
|---|---|---|---|---|
| 10 | NortheastTurbine | 704.4 | - | - |
| 11 | Rathdrum 1 | - | 2490.3 | - |
| 12 | Rathdrum 2 | - | 2490.3 | - |
| 13 | RCCCT | - | - | 13294.9 |

Plant Fuel Report (GBtu used)

| No. | Plant | SumasRock Gas | Rathdrum Gas | Kingsgate Gas |
|---|---|---|---|---|

| No. | Station | Max Cap MW | Hours | Fuel | Energy GWh | Fuel GBtu | Fuel Units | Cost $000 | Price ¢/MBtu |
|---|---|---|---|---|---|---|---|---|---|
| 10 | NortheastTurbine | 69.0 | 1012 | SumasRock Gas | 56.3 | 704.4 | | 2085.6 | 296.10 |
| 11 | Rathdrum 1 | 88.0 | 2856 | Rathdrum Gas | 220.4 | 2490.3 | | 7457.9 | 299.47 |
| 12 | Rathdrum 2 | 88.0 | 2856 | Rathdrum Gas | 220.4 | 2490.3 | | 7457.9 | 299.47 |
| 13 | RCCCT | 240.0 | 7481 | Kingsgate Gas | 1724.0 | 13294.9 | | 36611.1 | 275.38 |

# APPENDIX B

## Exhibit 1
## Alternative Resource Options
Source: NWPPC (6/00)

| | | Nominal Life-Cycle Levelized Cost (1999$) | | | |
|---|---|---|---|---|---|
| **Project Type** | **Fuel Type** | **Total** | **Capital** | **O&M** | **Fuel** |
| 250 MW CC - West & A2-14 Block 2 Base | Gas | 41.18 | 13.23 | 3.75 | 24.21 |
| 2x160 SCCT Low | Gas | 41.84 | 5.69 | 1.78 | 34.36 |
| 250 MW CC - Eastside Block 2 Base | Gas | 42.23 | 14.11 | 3.98 | 24.14 |
| 2x160 SCCT Base | Gas | 42.47 | 6.32 | 1.78 | 34.36 |
| 2x160 SCCT High | Gas | 43.09 | 6.95 | 1.78 | 34.36 |
| High Plains Wind (AB, MT, WY, CO, NM) | Wind | 60.77 | 47.77 | 13.00 | 0.00 |
| High Plains Wind (@ Main Grid) | Wind | 69.48 | 53.21 | 16.27 | 0.00 |
| Landfill Gas Recovery | Landfill Gas | 69.69 | 28.84 | 8.23 | 32.62 |
| Pacific Coast Wind (BC, OR, WA, CA) | Wind | 78.75 | 61.55 | 17.20 | 0.00 |
| Adv. Coal (PFBC) | Coal | 79.68 | 37.88 | 7.89 | 33.91 |
| Geothermal 4th Plan Group 1- Opt. | Geothermal | 79.71 | 59.77 | 19.94 | 0.00 |
| Geothermal 4th Plan Group 1- Base | Geothermal | 79.91 | 59.92 | 19.99 | 0.00 |
| Cascades Geothermal – Optimistic | Geothermal | 81.26 | 61.09 | 20.17 | 0.00 |
| Geothermal 4th Plan Group 1- Pessimistic | Geothermal | 81.35 | 60.52 | 20.83 | 0.00 |
| Cascades Geothermal – Base | Geothermal | 81.63 | 61.41 | 20.22 | 0.00 |
| Cascades Geothermal – Pessimistic | Geothermal | 82.34 | 61.72 | 20.62 | 0.00 |
| Conventional Coal (300 MW) | Coal | 88.57 | 41.25 | 9.78 | 37.54 |
| 80MW SCCT, 4/29 Pessimistic | Gas | 92.08 | 38.75 | 9.95 | 43.38 |
| Basin & Range Geothermal – Optimistic | Geothermal | 103.39 | 78.06 | 25.33 | 0.00 |
| Basin & Range Geothermal – Base | Geothermal | 103.57 | 78.24 | 25.33 | 0.00 |
| Basin & Range Geothermal – Pessimistic | Geothermal | 105.47 | 79.02 | 26.45 | 0.00 |
| 25 MW Bio-Gasification CC (4th Plan) | Biomass | 122.45 | 52.23 | 33.01 | 37.21 |
| Basin & Range Wind (ID, AZ, UT, NV) | Wind | 135.44 | 104.78 | 30.67 | 0.00 |
| 80MW SCCT, 4/29 Optimistic | Gas | 144.59 | 69.44 | 19.79 | 55.37 |
| 80MW SCCT, 4/29 Base | Gas | 148.45 | 73.30 | 19.79 | 55.37 |
| Aurora Fuel Cell (Distribution CG) | Gas | 172.68 | 125.13 | 25.37 | 22.17 |
| Eli PV @ Grid (50 miles) | Solar | 242.99 | 237.65 | 5.33 | 0.00 |
| Whitehorse PV @ Grid (50 miles) | Solar | 284.24 | 278.20 | 6.04 | 0.00 |
| Whitehorse PV @ Grid | Solar | 291.30 | 280.55 | 10.75 | 0.00 |
| PV Shingles | Solar | 558.37 | 549.86 | 8.51 | 0.00 |
| Roof Rack PV | Solar | 611.47 | 602.95 | 8.51 | 0.00 |
| Aurora Fuel Cell (Peaking) | Gas | 823.00 | 674.86 | 99.65 | 48.49 |

# APPENDIX C

# Triple-E Report

## December 1, 1999 to March 31, 2000

Avista Utilities Controllers Dept.
Resource Analysis Team
Jason Fletcher
Steve Negretti
Jon Powell

# Table of Contents

# Introduction

This is the second Triple-E Report produced in fulfillment of Avista Corporation's commitment at the time of the most recent Schedule 90 Tariff approval. This report covers quantitative results for the December 1, 1999 to March 31, 2000 trimester. It includes costs, energy savings, cost-effectiveness and descriptive statistics, Energy Efficiency Tariff Rider balances, measurement and evaluation (M&E) activities, policy updates, and large project disclosures.

Given that much of the basic methodology was covered in the prior report, we have excluded that discussion from this report. We are distributing an electronic version of the previous report for the reader's reference.

In place of the methodology discussion, this report includes approximately three times as many tables than were present in the last report. This is partially to facilitate comparison against the previous August 1 to November 30, 1999 trimester report, but this report also contains a more detailed disaggregation of our impact by jurisdiction and rateclass. Unless otherwise noted, the analytical methodology employed is unchanged from the prior report.

This is the first report where the *SalesLogix* database has been used. Data quality has improved in several areas of this process, including the incorporation of additional information fields and custom reports.

Although the format of the June 2000 Triple-E Board meeting does not include discussion of this report, we would appreciate the opportunity to meet with any Triple-E Board member interested in the full detail of these calculations, either individually or in small groups.

# General Analytical Notes

This section has been included to provide insight into analytical details that affect the results of this report. This includes relevant information regarding the treatment of raw data that influences the analysis.

## Database and Non-Database Projects

All Avista Corporation energy efficiency projects can be roughly divided into two categories; those that are tracked on a project-by-project basis through the *SalesLogix* database and those that are handled outside the database.

Non-database projects include the Resource Management Partnership Program (RMPP), the Limited Income program and the Natural Gas Awareness Campaign. The analyses of these programs are brought into the report only after a custom evaluation of their costs and benefits are completed.

Database projects are tracked individually through the *SalesLogix* database. Each of the characteristics relevant to the analysis, such as energy savings, non-energy benefits, utility revenue impact and customer cost, are specified based upon each project's unique characteristics.

### Database Project Details

Projects tracked through the database include all projects that are individually reviewed, as well as three measures that are analyzed in mass (due to the similarity of many of the project characteristics). Projects reviewed in mass are comprised of the following measures:

1) *VendingMI$ER*™

   *VendingMI$ER* is a control mechanism used to reduce the energy usage of cold drink vending machines. A prescriptive analysis of non-energy benefits resulting from *VendingMI$ER* installations revealed that a significant portion (20%) of the participant benefit from this measure accrue in the form of non-energy (maintenance) savings. These results have been incorporated into the analysis. Since this is a control device, benefits and costs accumulated through *VendingMI$ER* are allocated to the Controls technology.

2) LED Exit Signs

   A detailed analysis of LED exit sign annual energy savings was conducted in 1999, with the result being a revision from 240 kWh per sign to 200 kWh per sign. This was primarily based upon a higher inventory of compact fluorescents in the existing inventory than was anticipated. The analysis team has also completed a prescriptive analysis of non-energy benefits resulting from the installation of LED exit signs. The results of this analysis indicate that most (83%) of the participant benefit from this measure accrue in the form of non-energy (maintenance) savings. These results have been incorporated into the analysis. LED exit sign projects were incentivized as New Technologies. As such, benefits and costs accumulated through this program are allocated to the New Technologies measure.

3) LED Traffic Signals

   The energy savings from LED traffic signals are tracked by jurisdiction and are incorporated into the analysis. This measure has also been the subject of a non-energy benefit analysis by the analysis team. The results of this analysis indicate that a significant portion (42%) of the participant benefit from this measure accrue in the form of non-energy (maintenance) savings. These results have been incorporated into the analysis. LED traffic signal projects were incentivized as New Technologies. As such, benefits and costs accumulated through this program are allocated to the New Technologies measure.

<u>All Other Projects</u>

All projects tracked within *SalesLogix*, aside from those fitting the categories above, are individually analyzed for their impacts. All characteristics relevant to cost-effectiveness calculations and descriptive statistics are based upon project specific circumstances.

**Non-Database Project Details**

<u>Resource Management Partnership Program (RMPP)</u>

This program derives resource savings by placing resource managers in individual school districts. The resources affected include electric, natural gas (and other energy), water, sewer and solid waste. For the most part, the non-energy resource impacts occur early during the resource manager's work with the school district. During this particular trimester there were not any significant non-energy resource savings. Energy savings, however, do require the ongoing presence of a district resource manager and do not degrade as much as non-energy resource savings during the period of time that the resource manager is present.

The billing analysis captures the electric and natural gas savings. Non-utility energy impacts are captured on a site-specific basis. The billing analysis for the RMPP program has, over time, resulted in several policies dealing with such contingencies as new construction at an existing school site, the treatment of portable buildings, the aggregation or disaggregation of loads across multiple meters, and so on.

Projects for which the customer receives a direct incentive at a school site where a resource manager is present are removed from the metered savings calculation and credited to the technology that the direct incentive applies toward. For example, the savings from lighting projects at schools are removed from the billed energy savings and credited as an impact of the lighting technology. All billed energy savings remaining after these specific projects have been removed are attributed to resource management activities.

The resource management energy savings can then be characterized by three components; (1) behavioral, such as turning off the lights as necessary, (2) operational, such as utilizing existing controls or modifying the dispatch of end-uses and (3) hardwired measures that, for one reason or another, did not receive a direct incentive. In recognition of the short life of the behavioral and operational measures, in calculating the energy savings for any particular period of time it is assumed that 50% of the energy savings in the prior year and 25% of the energy savings two years preceding were readopted. This effect substantially increases the number of first-year kWh claimed by the program, but it also results in a weighted average life of only four years for these billed energy savings.

At this point we don't have enough data on school districts that have discontinued their resource manager program to verify the accuracy of the measure persistence figures being used.

<u>Limited Income</u>

The Limited Income program obtains energy savings through weatherization improvements and electric to gas conversions (space heat and domestic hot water) for qualified electric utility customers. These savings enter the analysis by applying the results of a detailed billing analysis study completed in 1999 to the water heat and space heat conversions claimed through the program. The weatherization savings are based upon engineering estimates specific to the dwelling. Since the vast majority (99%) of the energy savings in this segment is from fuel-conversions, this has been the focus of the measurement and evaluation efforts to date.

The Limited Income program also funds structural and mechanical repairs to qualified homes, subject to a cap, if they are necessary to ensure the persistence of the energy measures installed, or if they are necessary on a health and human safety basis. It is assumed the benefits derived from these repairs have a non-energy benefit commensurate with their costs.

In this particular trimester no costs associated with these repairs were reported to the analysis team. We will be following up on these impacts in more detail in the next trimester to determine if expenses had been incurred that were not captured as non-energy benefits.

Since these programs are operated in conjunction with community action program (CAP) agencies as part of their overall offerings to this customer segment, the utility costs of the programs are fairly minimal. This leveraging strategy has substantially contributed to a cost-effectiveness higher than would be expected out of this segment.

To clarify the meaning of the various tables reporting on this program, the customer cost is equal to the utility incentive for the limited income programs because all costs associated with energy savings are paid for through the incentive.

<u>Natural Gas Awareness Campaign (NGAC)</u>

The effects of the NGAC are incorporated into the analysis based upon the most recent information on actual residential conversions of space heating, water heating, clothes dryers, ovens and ranges. The first 1,000 space heating conversions are excluded on the basis that these customers are part of the natural adoption in our service territory. This is the only program that excludes the energy savings of free-riders (or natural adopters).

The savings for this program will be adjusted when recently completed survey information is subjected to our energy savings analysis and verification.

## Non-Quantifiable Non-Energy Impacts

The analytical group has been working to further develop means of quantifying, where possible, and identifying, where quantification is unreasonable, the non-energy impacts of our projects. The reason for this is twofold; (1) to more accurately represent the cost-effectiveness of the projects and (2) to provide management information about the overall benefits of our programs. This information will be used to refine the marketing of energy efficiency technologies.

At present our quantification of non-energy effects has been limited to two primary components; (1) modifying the capital cost of projects to reflect differences in end-use equipment life and (2) incorporating the maintenance savings. The quantified maintenance savings is almost exclusively related to lighting projects. The non-quantifiable value of these non-energy benefits must be taken into consideration when interpreting much of this analysis, and in particular the TRC test results.

We are endeavoring to improve our ability to identify and quantify these non-energy benefits in the future. One of the changes implemented to address this issue is detailed under the *Notable Projects, Disclosures and Policy Update* section of this report.

# Quantitative Results

The following contains descriptions of the methodologies used for completion of the cost-effectiveness analysis and descriptive statistics for the December 1, 1999 to March 31, 2000 trimester. Observations noted in the course of performing this analysis have been noted as well.

## Allocation of Utility Costs

This allocation methodology is essentially unchanged from our previous report.

The raw data for utility non-incentive costs comes in the form of actual expenses and journal entries incurred by Tariff Rider accounts. The raw data for direct incentive costs comes in the form of accrual-based expenses, drawn from the *SalesLogix* database. While non-incentive costs represent real expenditures, incentives are de-rated in the same manner as kWh, therms, etc. As such, incentives applied to projects in the Contracted phase are accounted for at 75%, those applied to projects in the Construction phase are accounted for at 95%, and those applied to Completed projects are accounted for at 100%. This methodology was adopted this trimester in an effort to more closely align expenditures with committed funds.

Each expenditure is incurred through an account number specific to the appropriate customer segment, to an "old" program (prior to our shift to the customer segment model), or to general implementation or M&E. In order to attribute all costs to customer segments and technologies, three allocations must be made. The first allocation assigns the expenses associated with the old programs to customer segments. Next, the general implementation and general M&E expense are allocated to customer segments. Last, the utility non-incentive expenses associated with, or allocated to, each customer segment are allocated to individual technologies within that segment.

The overall allocation process is heavily dependent upon the judgement of the individuals performing the allocation. The meaningfulness of these allocations is handicapped by the joint cost nature of many expenditures. An audit, site visit, or marketing effort is generally targeted towards multiple technologies.

Consequently there is the potential for technologies which are cost-effective contributors to the overall portfolio to be cost-ineffective as a result of being burdened with a disproportionate amount of allocated general costs. This should be considered when reviewing both cost-effectiveness ratios and net cost-effectiveness results.

In our previous Triple-E Report we noted that the proportion of utility costs allocated to one of the general categories seemed excessive. The general implementation and general M&E categories were only to be used if a cost could not be reasonably allocated to one or more individual customer segments. We reiterated the need for accurate reporting of these costs to the staff on several occasions after that point. The net result was an insignificant reduction in the proportion of costs charged to general (27.7% to 27.5%). We will continue to follow up on this task, but our tentative interpretation is that the allocation to general costs is appropriate in spite of the initial appearances.

Refer to *Tables 1-4* for utility costs allocated across programs, customer segments, and technologies.

Table 1 Utility Costs Aggregated by Programs and Customer Segments

| | Implementation | Incentives[1] | M&E | TOTAL |
|---|---|---|---|---|
| **SEGMENTS** | | | | |
| Agriculture | $ 8,756 | $ - | $ - | $ 8,756 |
| Education | $ 120,099 | $ 208,958 | $ 2,912 | $ 331,969 |
| Food Service | $ 12,947 | $ 16,200 | $ 1,396 | $ 30,543 |
| Health Care | $ 11,486 | $ 22,715 | $ 78 | $ 34,279 |
| Hospitality | $ 24,784 | $ 25,240 | $ 1,241 | $ 51,265 |
| Limited Income | $ 12,960 | $ 414,492 | $ - | $ 427,452 |
| Manufacturing | $ 104,638 | $ 127,739 | $ 941 | $ 233,318 |
| Office | $ 26,709 | $ 30,441 | $ 3,004 | $ 60,154 |
| Residential[2] | $ 77,689 | $ 319 | $ - | $ 78,007 |
| Retail | $ 21,789 | $ 7,657 | $ 620 | $ 30,066 |
| **GENERAL** | | | | |
| General (Implementation) | $ 624,456 | $ - | $ - | $ 624,456 |
| General (M&E) | $ - | $ - | $ 87,813 | $ 87,813 |
| **OTHER EXPENDITURES** | | | | |
| NEEA[3] | $ 3,232 | $ 442,005 | $ - | $ 445,237 |
| Leases[4] | $ 5,867 | $ 44,798 | $ - | $ 50,665 |
| **OLD PROGRAMS** | | | | |
| LED Traffic Signals | $ 1,112 | $ 30,105 | $ - | $ 31,217 |
| New Technologies | $ 1,698 | $ 28,548 | $ - | $ 30,246 |
| Prescriptive HVAC | $ 17 | $ - | $ - | $ 17 |
| Prescriptive Lighting | $ 319 | $ 1,157 | $ 360 | $ 1,836 |
| RMPP | $ - | $ 475 | $ - | $ 475 |
| Site Specific | $ 25,186 | $ 3,020 | $ 110 | $ 28,316 |
| SS-VFD | $ - | $ 344 | $ - | $ 344 |
| Trade Ally | $ 2,779 | $ 3,293 | $ 110 | $ 6,182 |
| **TOTAL** | **$ 1,086,523** | **$ 1,407,504** | **$ 98,585** | **$ 2,592,611** |
| | | | | |
| **BROKEN OUT BY CATEGORY** | | | | |
| Total assigned to segments | $ 421,857 | $ 853,761 | $ 10,192 | $ 1,285,809 |
| Total assigned to general | $ 624,456 | $ - | $ 87,813 | $ 712,269 |
| Total assigned to other | $ 9,099 | $ 486,803 | $ - | $ 495,902 |
| Total assigned to old programs | $ 31,111 | $ 66,940 | $ 580 | $ 98,631 |
| **TOTAL** | **$ 1,086,523** | **$ 1,407,504** | **$ 98,585** | **$ 2,592,611** |
| | | | | |
| **CATEGORY AS A PERCENT** | | | | |
| Total assigned to segment | 16.3% | 32.9% | 0.4% | 49.6% |
| Total assigned to general | 24.1% | 0.0% | 3.4% | 27.5% |
| Total assigned to other | 0.4% | 18.8% | 0.0% | 19.1% |
| Total assigned to old programs | 1.2% | 2.6% | 0.0% | 3.8% |
| **TOTAL** | **41.9%** | **54.3%** | **3.8%** | **100.0%** |

**NOTES:**

1) Incentives are accounted for on an accrual basis, and are therefore de-rated (in the same way as kWh, therms, etc.)
2) Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.
3) Costs associated with membership in NEEA are included in this table, but are excluded from all other tables.
4) Costs associated with outstanding leases are included in this table, but are excluded from all other tables.

**Table 2** — Assignment of Utility Costs to Customer Segments

| | Assigned Impl. [A] | Assigned M&E [B] | Total util assigned non-incent $ [C] | Gen Impl allocated [D] | Gen M&E allocated [E] | Total alloc overhead [F] | Old pgm alloc impl cost [G] | Old pgm alloc M&E cost [H] | Total old pgm non-incent allocations [I] | TOTAL IMPL [J] | TOTAL M&E [K] | TOTAL INCENTIVE [L] | GRAND TOTAL [M] | Allocated ovhd as % of total [N] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Agriculture | $ 8,756 | $ - | $ 8,756 | $ 14,522 | $ 7,082 | $ 21,604 | $ 425 | $ - | $ 425 | $ 23,703 | $ 7,082 | $ - | $ 30,784 | 70.2% |
| Education | $ 120,099 | $ 2,912 | $ 123,011 | $ 116,178 | $ 11,870 | $ 128,047 | $ 10,538 | $ 79 | $ 10,617 | $ 246,815 | $ 14,861 | $ 237,932 | $ 499,608 | 25.6% |
| Food Service | $ 12,947 | $ 1,396 | $ 14,343 | $ 29,044 | $ 8,253 | $ 37,297 | $ 480 | $ 47 | $ 527 | $ 42,471 | $ 9,696 | $ 16,200 | $ 68,366 | 54.6% |
| Health Care | $ 11,486 | $ 78 | $ 11,564 | $ 58,089 | $ 8,809 | $ 66,898 | $ 5,501 | $ 51 | $ 5,552 | $ 75,076 | $ 8,938 | $ 22,715 | $ 106,729 | 62.7% |
| Hospitality | $ 24,784 | $ 1,241 | $ 26,025 | $ 87,133 | $ 10,354 | $ 97,487 | $ 480 | $ 47 | $ 527 | $ 112,397 | $ 11,642 | $ 25,783 | $ 149,822 | 65.1% |
| Limited Income | $ 12,960 | $ - | $ 12,960 | $ 72,611 | $ 9,656 | $ 82,267 | $ - | $ - | $ - | $ 85,571 | $ 9,656 | $ 414,492 | $ 509,718 | 16.1% |
| Manufacturing | $ 104,638 | $ 941 | $ 105,579 | $ 116,178 | $ 11,870 | $ 128,047 | $ 8,422 | $ 46 | $ 8,469 | $ 229,238 | $ 12,857 | $ 161,816 | $ 403,911 | 31.7% |
| Office | $ 26,709 | $ 3,004 | $ 29,713 | $ 58,089 | $ 8,627 | $ 66,716 | $ 2,627 | $ 110 | $ 2,737 | $ 87,425 | $ 11,741 | $ 33,228 | $ 132,394 | 50.4% |
| Residential | $ 77,689 | $ - | $ 77,689 | $ 29,044 | $ 5,355 | $ 34,399 | $ 17 | $ - | $ 2,822 | $ 106,750 | $ 5,355 | $ 319 | $ 112,424 | 30.6% |
| Retail | $ 21,789 | $ 620 | $ 22,409 | $ 43,567 | $ 5,940 | $ 49,507 | $ 2,622 | $ 200 | $ 2,822 | $ 67,978 | $ 6,760 | $ 8,217 | $ 82,954 | 59.7% |
| | $ 421,857 | $ 10,192 | $ 432,049 | $ 624,456 | $ 87,813 | $ 712,269 | $ 31,111 | $ 580 | $ 34,496 | $ 1,077,424 | $ 98,585 | $ 920,701 | $ 2,096,709 | |

[A] The implementation cost charged directly to that customer segment.
[B] The M&E cost charged directly to that customer segment.
[C] The total utility non-incentive cost of the customer segment.
[D] The general implementation cost allocated to the customer segment.
[E] The general M&E cost allocated to the customer segment
[F] The total allocated general cost.
[G] The implementation cost allocated from 'old programs' (those not specified as customer segments in the new tariff) to new customer segments.
[H] The M&E cost allocated from 'old programs' (those not specified as customer segments in the new tariff) to new customer segments.
[I] The total non-incentive cost allocated from old programs to new customer segments.
[J] Total implementation cost for the customer segment, including allocated general cost and allocated implementation cost from old programs.
[K] Total M&E cost for the customer segment, including allocated general M&E and allocated M&E cost from old programs.
[L] Total incentives paid under both old programs and new segments during the trimester to customers within this customer segment.
[M] Total utility cost (including incentives) for the customer segment.
[N] The allocation of general implementation and M&E cost as a percent of the total program cost.

**NOTES:**

Incentives are accounted for on an accrual basis, and are therefore de-rated (in the same way as kWh, therms, etc.)
Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.
Costs associated with membership in NEEA are excluded from this table, and are excluded from all cost-effectiveness calculations.
Costs associated with outstanding leases are excluded from this table, and are excluded from all cost-effectiveness calculations.

Table 3

Allocation of Utility Costs Across Customer Segments and Technologies

| | Appliances | Assistive Technologies | Compressed Air | Controls | HVAC | Industrial Process | Lighting | Monitoring | Motors | New Tech | Renewables | Resource Management | Shell | Sustainable Building | TOTAL $ | % of Portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Agriculture | $ - | $ - | $ - | $ 12,314 | $ - | $ 6,157 | $ - | $ - | $ 12,314 | $ - | $ - | $ - | $ - | $ - | $ 30,784 | 1.5% |
| Education | $ - | $ - | $ - | $ 60,606 | $ 44,723 | $ - | $ 262,220 | $ - | $ - | $ 38,603 | $ - | $ 84,110 | $ 9,346 | $ - | $ 499,608 | 23.8% |
| Food Service | $ - | $ - | $ - | $ 21,096 | $ 20,867 | $ - | $ 15,650 | $ 5,217 | $ - | $ 320 | $ - | $ - | $ 5,217 | $ - | $ 68,366 | 3.3% |
| Health Care | $ - | $ - | $ - | $ 8,844 | $ 17,687 | $ 4,422 | $ 17,687 | $ 4,422 | $ 4,422 | $ 31,559 | $ - | $ 13,265 | $ 4,422 | $ - | $ 106,729 | 5.1% |
| Hospitality | $ - | $ - | $ - | $ 16,628 | $ 31,010 | $ - | $ 52,441 | $ - | $ - | $ 49,742 | $ - | $ - | $ - | $ - | $ 149,822 | 7.1% |
| Limited Income | $ 133,067 | $ 34,228 | $ - | $ - | $ 325,904 | $ - | $ - | $ - | $ 5,793 | $ - | $ - | $ - | $ 10,726 | $ - | $ 509,718 | 24.3% |
| Manufacturing | $ - | $ - | $ 28,977 | $ 33,326 | $ 63,602 | $ 22,269 | $ 29,613 | $ 14,385 | $ 27,869 | $ 183,871 | $ - | $ - | $ - | $ - | $ 403,911 | 19.3% |
| Office | $ - | $ - | $ - | $ 26,913 | $ 27,045 | $ - | $ 46,386 | $ - | $ 9,015 | $ 18,781 | $ - | $ - | $ (4,761) | $ 9,015 | $ 132,394 | 6.3% |
| Residential | $ 11,264 | $ 70,465 | $ - | $ 319 | $ 30,375 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 112,424 | 5.4% |
| Retail | $ - | $ - | $ - | $ 10,430 | $ 20,383 | $ - | $ 40,490 | $ - | $ - | $ 1,460 | $ - | $ - | $ 10,192 | $ - | $ 82,954 | 4.0% |
| TOTAL $ | $ 144,331 | $ 104,694 | $ 28,977 | $ 190,475 | $ 581,596 | $ 32,848 | $ 464,487 | $ 24,023 | $ 59,413 | $ 324,336 | $ - | $ 97,375 | $ 35,140 | $ 9,015 | $ 2,096,709 | 100.0% |
| % of portfolio | 6.9% | 5.0% | 1.4% | 9.1% | 27.7% | 1.6% | 22.2% | 1.1% | 2.8% | 15.5% | 0.0% | 4.6% | 1.7% | 0.4% | 100.0% | |

NOTES:

Incentives are accounted for on an accrual basis, and are therefore de-rated (in the same way as kWh, therms, etc.)

Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.

Costs associated with membership in NEEA are excluded from this table, and are excluded from all cost-effectiveness calculations.

Costs associated with outstanding leases are excluded from this table, and are excluded from all cost-effectiveness calculations.

**Table 4** **Allocation of Direct Incentives Across Customer Segments and Technologies**

| | Appliances | Assistive Technologies | Compressed Air | Controls | HVAC | Industrial Process | Lighting | Monitoring | Motors | New Tech | Renewables | Resource Management | Shell | Sustainable Building | TOTAL $ | % of Portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Agriculture | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | 0.0% |
| Education | $ - | $ - | $ - | $ 32,570 | $ (2,005) | $ - | $ 178,110 | $ - | $ - | $ 29,258 | $ - | $ - | $ - | $ - | $ 237,932 | 25.8% |
| Food Service | $ - | $ - | $ - | $ 15,880 | $ - | $ - | $ - | $ - | $ - | $ 320 | $ - | $ - | $ - | $ - | $ 16,200 | 1.8% |
| Health Care | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 22,715 | $ - | $ - | $ - | $ - | $ 22,715 | 2.5% |
| Hospitality | $ - | $ - | $ - | $ 1,123 | $ - | $ - | $ 21,432 | $ - | $ - | $ 3,228 | $ - | $ - | $ - | $ - | $ 25,783 | 2.8% |
| Limited Income | $ 129,204 | $ - | $ - | $ - | $ 274,562 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 10,726 | $ - | $ 414,492 | 45.0% |
| Manufacturing | $ - | $ - | $ 6,565 | $ 5,456 | $ 7,092 | $ 756 | $ 972 | $ - | $ - | $ 140,974 | $ - | $ - | $ - | $ - | $ 161,816 | 17.6% |
| Office | $ - | $ - | $ - | $ 8,883 | $ - | $ - | $ 19,341 | $ - | $ - | $ 9,766 | $ - | $ - | $ (4,761) | $ - | $ 33,228 | 3.6% |
| Residential | $ - | $ - | $ - | $ 319 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 319 | 0.0% |
| Retail | $ - | $ - | $ - | $ 238 | $ - | $ - | $ 6,518 | $ - | $ - | $ 1,460 | $ - | $ - | $ - | $ - | $ 8,217 | 0.9% |
| TOTAL $ | $ 129,204 | $ - | $ 6,565 | $ 64,469 | $ 279,649 | $ 756 | $ 226,373 | $ - | $ - | $ 207,720 | $ - | $ - | $ 5,965 | $ - | $ 920,701 | 100.0% |
| % of portfolio | 14.0% | 0.0% | 0.7% | 7.0% | 30.4% | 0.1% | 24.6% | 0.0% | 0.0% | 22.6% | 0.0% | 0.0% | 0.6% | 0.0% | 100.0% | |

**NOTES:**

Incentives are accounted for on an accrual basis, and are therefore de-rated (in the same way as kWh, therms, etc.)

Incentive costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.

Incentive costs associated with membership in NEEA are excluded from this table, and are excluded from all cost-effectiveness calculations.

Incentive costs associated with outstanding leases are excluded from this table, and are excluded from all cost-effectiveness calculations.

## Treatment of De-Rated Project Results

As previously mentioned, projects in the Contracted and Construction phases are credited with 75% and 95% of the engineering estimates. This applies to kWh savings, therm savings, direct incentives, non-energy benefits, and customer costs.

## Energy Savings

During this trimester Avista participated in over 12.3 million kWh of energy savings, which resulted in an increase of approximately 137,000 therms of natural gas usage. This represents the progress of projects within the "pipeline" of the five sequential phases during the trimester.

As always, the net therm savings incorporate the additional therm usage of electric to natural gas conversions. The largest therm contributors this trimester were the Natural Gas Awareness Campaign and the conversion component of the Limited Income program.

Avista Corporation's participation in the Northwest Energy Efficiency Alliance is within this report for purposes of calculating utility costs, but has been excluded for cost-effectiveness purposes. This is due to the lack of definable energy savings at this point in time. During this trimester, NEEA accounted for 17.2% of our utility costs.

These calculations of energy savings do not include any estimates of free-riders, free-drivers, or any market transformation effects. At this point it is unclear how these effects will influence the total energy savings of the portfolio. We will be investigating this question in the near future in compliance with our Idaho general ratecase order.

Refer to *Tables 5 and 6* for the allocations of electric and therm savings (increases) across customer segments and technologies.

**Table 5**

**Allocation of Electric Savings Across Customer Segments and Technologies**

| | Appliances | Assistive Technologies | Compressed Air | Controls | HVAC | Industrial Process | Lighting | Monitoring | Motors | New Tech | Renewables | Resource Management | Shell | Sustainable Building | TOTAL kWh | % of Portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Agriculture | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0% |
| Education | - | - | - | 470,952 | 5,223 | - | 2,948,586 | - | - | 367,783 | - | 1,108,974 | - | - | 4,901,519 | 39.8% |
| Food Service | - | - | - | 245,861 | 21,240 | - | - | - | - | 3,200 | - | - | - | - | 270,301 | 2.2% |
| Health Care | - | - | - | - | - | - | - | - | - | 216,525 | - | - | - | - | 216,525 | 1.8% |
| Hospitality | - | - | - | 12,375 | - | - | 253,767 | - | - | 36,600 | - | - | - | - | 302,742 | 2.5% |
| Limited Income | 641,478 | - | - | - | 1,295,502 | - | - | - | - | - | - | - | 20,054 | - | 1,957,034 | 15.9% |
| Manufacturing | - | - | 122,788 | 91,778 | 124,507 | 15,127 | 117,066 | - | - | 1,168,019 | - | - | - | - | 1,639,284 | 13.3% |
| Office | - | - | - | 114,520 | 34,493 | - | 350,821 | - | - | 103,021 | - | - | (59,651) | - | 543,204 | 4.4% |
| Residential | 460,187 | - | - | 6,755 | 1,790,841 | - | - | - | - | - | - | - | - | - | 2,257,783 | 18.3% |
| Retail | - | - | - | 2,825 | - | - | 214,646 | - | - | 14,607 | - | - | - | - | 231,878 | 1.9% |
| TOTAL kWh | 1,101,665 | - | 122,788 | 944,887 | 3,271,805 | 15,127 | 3,884,886 | - | - | 1,909,755 | - | 1,108,974 | (39,597) | - | 12,320,271 | 100.0% |
| % of portfolio | 8.9% | 0.0% | 1.0% | 7.7% | 26.6% | 0.1% | 31.5% | 0.0% | 0.0% | 15.5% | 0.0% | 9.0% | -0.3% | 0.0% | 100.0% | |

NOTE: These figures include de-rated electric savings from the Contracted and Construction phases.

**Table 6**

**Allocation of Natural Gas Savings Across Customer Segments and Technologies**

| | Appliances | Assistive Technologies | Compressed Air | Controls | HVAC | Industrial Process | Lighting | Monitoring | Motors | New Tech | Renewables | Resource Management | Shell | Sustainable Building | TOTAL Therms | % of Portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Agriculture | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0% |
| Education | - | - | - | 8,984 | - | - | (10,809) | - | - | (51) | - | 40,299 | - | - | 38,404 | -28.1% |
| Food Service | - | - | - | - | 672 | - | - | - | - | - | - | - | - | - | 672 | -0.5% |
| Health Care | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0% |
| Hospitality | - | - | - | - | - | - | (319) | - | - | - | - | - | - | - | (319) | 0.2% |
| Limited Income | (17,510) | - | - | - | (35,362) | - | - | - | - | - | - | - | (547) | - | (53,419) | 39.1% |
| Manufacturing | - | - | - | - | - | - | (138) | - | - | - | - | - | - | - | (138) | 0.1% |
| Office | - | - | - | - | - | - | (2,583) | - | - | - | - | - | (21,904) | - | (24,487) | 17.9% |
| Residential | (19,633) | - | - | - | (76,402) | - | - | - | - | - | - | - | - | - | (96,034) | 70.3% |
| Retail | - | - | - | - | - | - | (1,199) | - | - | - | - | - | - | - | (1,199) | 0.9% |
| TOTAL Therms | (37,143) | - | - | 8,984 | (111,092) | - | (15,048) | - | - | (51) | - | 40,299 | (22,451) | - | (136,521) | 100.0% |
| % of portfolio | 27.2% | 0.0% | 0.0% | -6.6% | 81.4% | 0.0% | 11.0% | 0.0% | 0.0% | 0.0% | 0.0% | -29.5% | 16.4% | 0.0% | 100.0% | |

NOTE: These figures include de-rated natural gas savings from the Contracted and Construction phases.

## Customer Costs and Non-Energy Benefits

A summary of customer costs incurred to achieve the energy savings portion of the projects captured in this report has been included. The raw customer costs have been modified to exclude non-electric components of customer projects, and to appropriately match the measure life of base-case and high-efficiency alternatives. Customer cost figures listed are also not adjusted for direct incentives granted by Avista Corporation.

These customer costs substantially affect the total resource cost test and the participant test. Customer costs amount to approximately two-thirds of the total resource and participant costs.

The non-energy benefit data reflects the quantifiable non-energy benefits accruing to the energy efficiency projects. To date these quantifiable non-energy benefits are limited to maintenance savings inherent in LED exit sign, LED traffic signal, *VendingMI$ER*, and non-residential lighting projects.

We are continuing our research to quantify other non-energy benefits such as productivity, safety, retail sales and so forth. To date we have not found a sufficient body of research that would reasonably substantiate the numerical claims that have been made in these areas. These as yet non-quantifiable non-energy benefits are clearly major influences on the adoption of energy efficiency measures and on the cost-effectiveness of our portfolio, and they are actively used in marketing these measures to our customers.

We are reviewing the database projects in greater depth to obtain information about increased production and other relatively easily quantifiable values. We will also be working to better identify what non-energy benefits accrue to what measures, even if those benefits are non-quantifiable.

Refer to *Tables 7 and 8* for the allocations of customer costs and non-energy benefits across customer segments and technologies.

**Table 7**

**Allocation of Non-Energy Benefits Across Customer Segments and Technologies**

| | Appliances | Assistive Technologies | Compressed Air | Controls | HVAC | Industrial Process | Lighting | Monitoring | Motors | New Tech | Renewables | Resource Management | Shell | Sustainable Building | TOTAL NEB $ | % of Portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Agriculture | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | 0.0% |
| Education | $ - | $ - | $ - | $ 28,052.65 | $ - | $ - | $ 535,510.51 | $ - | $ - | $ 542,105.01 | $ - | $ - | $ - | $ - | $ 1,105,668.18 | 62.3% |
| Food Service | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 4,775.07 | $ - | $ - | $ - | $ - | $ 4,775.07 | 0.3% |
| Health Care | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 190,704.18 | $ - | $ - | $ - | $ - | $ 190,704.18 | 10.7% |
| Hospitality | $ - | $ - | $ - | $ 37,582.47 | $ - | $ - | $ 24,221.83 | $ - | $ - | $ 54,614.81 | $ - | $ - | $ - | $ - | $ 116,419.11 | 6.6% |
| Limited Income | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | 0.0% |
| Manufacturing | $ - | $ - | $ - | $ 6,406.42 | $ - | $ - | $ 8,065.60 | $ - | $ - | $ 1,790.65 | $ - | $ - | $ - | $ - | $ 16,262.67 | 0.9% |
| Office | $ - | $ - | $ - | $ 6,584.83 | $ - | $ - | $ 101,048.63 | $ - | $ - | $ 153,728.76 | $ - | $ - | $ - | $ - | $ 261,362.23 | 14.7% |
| Residential | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | 0.0% |
| Retail | $ - | $ - | $ - | $ 219.49 | $ - | $ - | $ 58,252.93 | $ - | $ - | $ 21,796.68 | $ - | $ - | $ - | $ - | $ 80,269.11 | 4.5% |
| TOTAL NEB $ | $ - | $ - | $ - | $ 78,845.87 | $ - | $ - | $ 727,099.51 | $ - | $ - | $ 969,515.16 | $ - | $ - | $ - | $ - | $ 1,775,460.54 | 100.0% |
| % of portfolio | 0.0% | 0.0% | 0.0% | 4.4% | 0.0% | 0.0% | 41.0% | 0.0% | 0.0% | 54.6% | 0.0% | 0.0% | 0.0% | 0.0% | 100.0% | |

NOTE: The non-energy benefit figures contained in this table are listed as net present value (NPV).

**Table 8**

**Allocation of Customer Costs Across Customer Segments and Technologies**

| | Appliances | Assistive Technologies | Compressed Air | Controls | HVAC | Industrial Process | Lighting | Monitoring | Motors | New Tech | Renewables | Resource Management | Shell | Sustainable Building | TOTAL NEB $ | % of Portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Agriculture | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | 0.0% |
| Education | $ - | $ - | $ - | $ 118,768.04 | $ (3,243.50) | $ - | $ 526,632.10 | $ - | $ - | $ 90,483.60 | $ - | $ - | $ - | $ - | $ 732,640.24 | 29.1% |
| Food Service | $ - | $ - | $ - | $ 31,780.25 | $ - | $ - | $ - | $ - | $ - | $ 787.28 | $ - | $ - | $ - | $ - | $ 32,547.53 | 1.3% |
| Health Care | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 47,961.40 | $ - | $ - | $ - | $ - | $ 47,961.40 | 1.9% |
| Hospitality | $ - | $ - | $ - | $ 1,310.93 | $ - | $ - | $ 29,713.11 | $ - | $ - | $ 9,004.49 | $ - | $ - | $ - | $ - | $ 40,028.52 | 1.6% |
| Limited Income | $ 129,204.43 | $ - | $ - | $ - | $ 274,561.59 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 10,725.52 | $ - | $ 414,491.54 | 16.5% |
| Manufacturing | $ - | $ - | $ 15,269.35 | $ 9,474.70 | $ 29,059.00 | $ - | $ 8,854.00 | $ - | $ - | $ 850,579.23 | $ - | $ - | $ - | $ - | $ 713,236.28 | 28.3% |
| Office | $ - | $ - | $ - | $ 23,927.15 | $ 5,000.00 | $ - | $ 6,021.75 | $ - | $ - | $ 25,345.66 | $ - | $ - | $ 86,042.00 | $ - | $ 146,336.56 | 5.8% |
| Residential | $ 145,514.63 | $ - | $ - | $ 750.00 | $ 234,674.41 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 380,938.94 | 15.1% |
| Retail | $ - | $ - | $ - | $ 282.15 | $ - | $ - | $ 5,745.41 | $ - | $ - | $ 3,593.68 | $ - | $ - | $ - | $ - | $ 9,621.24 | 0.4% |
| TOTAL NEB $ | $ 274,718.96 | $ - | $ 15,269.35 | $ 186,273.21 | $ 540,051.50 | $ - | $ 576,966.37 | $ - | $ - | $ 827,755.34 | $ - | $ - | $ 96,767.52 | $ - | $ 2,517,802.25 | 100.0% |
| % of portfolio | 10.9% | 0.0% | 0.6% | 7.4% | 21.4% | 0.0% | 22.9% | 0.0% | 0.0% | 32.9% | 0.0% | 0.0% | 3.8% | 0.0% | 100.0% | |

NOTE: The customer cost figures contained in this table are not adjusted for incentives received. Instead, they reflect the entire de-rated cost of the energy efficiency project.

## Cost-Effectiveness and Descriptive Statistics

The following tables contain cost-effectiveness statistics for this trimester for all four standard practice tests. Also included are net benefits for each test by customer segment and technology. Net benefits have been included to give additional insight into the significance of each segment and technology.

The Total Resource Cost (TRC) ratio is essentially unchanged from the previous trimester (1.12 to 1.11). It is too early to ascertain if we were correct in our expectation that TRC cost-effectiveness would increase as the one-time costs incurred in the August 1 to November 30, 1999 trimester were completed. As of yet, we do not have enough history of calculating cost-effectiveness on a trimesterly basis to determine if the normal variation could conceal a meaningful increase in cost-effectiveness.

The Utility Cost Test (UCT) ratio has fallen significantly from the previous trimester (2.11 to 1.11). As mentioned previously, we are uncertain as to the normal variation that we should expect when cost-effectiveness is calculated on a trimesterly basis, but it seems unlikely that a change of this magnitude is within normal variation. It is more likely that it is the result of the imposition of the new Schedule 90 Tariff and the higher incentives contained therein. Supporting this hypothesis is the fact that the proportion of "old programs" (those projects being completed under the old tariff) has fallen significantly from the previous trimester.

It is possible that the decline in the UCT ratio will continue into the next trimester, as the last of the "old programs" reach completion and the project pipeline is composed completely of the higher incentive projects being completed under the new tariff. If this is the case, a management review of the portfolio would be warranted to address the issue of identifying what the minimum acceptable UCT ratio is and how the portfolio can be managed to achieve it.

The participant test ratio has moved from 2.98 to 4.46 in the last trimester. This increase lends a certain amount of corroboration to the theory that the UCT ratio is falling as a result of increased utility direct incentives. It may also imply that the free-ridership ratio has improved as a result of offering enhanced incentives (the larger the incentive and the higher the participant ratio the more likely it is that the program made the difference in adoption of the measure). The tiering of the incentives based upon simple payback may further enhance that effect.

These interpretations will be incorporated into the free-ridership analysis that the Company was requested to perform under the recently completed Idaho ratecase order. This may impact the timing of the study. Having established the hypothesis that the new programs appear to be impacting the free-ridership ratio, it would be necessary to segment "old" programs from "new" programs to develop an accurate view of free-ridership.

The non-participant test ratio (also called the rate impact measure) experienced a slight decline from 0.44 to 0.33. As had been previously indicated, Avista is mathematically guaranteed to fail this test (have a ratio below 1.0) as long as our rates are above our avoided costs. The Avista response has been to offer a broad enough program portfolio to provide every customer the opportunity to directly or indirectly benefit from our portfolio. The meaning of a non-participant test is diminished as these program benefits become more widely distributed.

Comparison to the previous trimester indicates a slight increase in the customer cost per kWh (18 cents/kWh to 20 cents/kWh). A change of this magnitude is likely to be within the normal variation of a trimesterly report.

The utility implementation cost also increased from 7 cents/kWh to 10 cents/kWh. This is attributable to the reduction in energy savings from 14.2 million kWh to 12.3 million kWh. The utility implementation costs actually fell from the previous trimester.

We have added a measure of incentive cost per kWh to assist in diagnosing the UCT ratio issue, as previously discussed. The increase in incentive cost per kWh from five cents to seven cents reflects the most recent change to the Schedule 90 Tariff.

Refer to *Tables 9 and 10* for summaries of cost-effectiveness for all four standard practice tests by customer segments and technologies.

Refer to *Tables 11 and 12* for summaries of net benefits for all four standard practice tests by customer segments and technologies.

Refer to *Table 13* for further details on the calculation of the cost-effectiveness rations, as well as some useful descriptive statistics.

**Table 9** **Cost-Effectiveness Statistics by Customer Segment**

| | Total Resource Cost Test | Utility Cost Test | Participant Test | Non-Participant Test |
|---|---|---|---|---|
| Agriculture | - | - | N/A | - |
| Education | 1.96 | 1.70 | 5.89 | 0.36 |
| Food Service | 0.62 | 0.70 | 7.05 | 0.26 |
| Health Care | 1.74 | 0.37 | 10.35 | 0.22 |
| Hospitality | 1.06 | 0.38 | 16.42 | 0.22 |
| Limited Income | 0.91 | 0.91 | N/A | 0.29 |
| Manufacturing | 0.34 | 0.75 | 0.90 | 0.34 |
| Office | 1.33 | 0.49 | 3.84 | 0.27 |
| Residential | 0.92 | 4.03 | 3.18 | 0.37 |
| Retail | 1.46 | 0.51 | 127.18 | 0.24 |
| **PORTFOLIO** | **1.11** | **1.11** | **4.46** | **0.33** |

**Table 10** **Cost-Effectiveness Statistics by Technology**

| | Total Resource Cost Test | Utility Cost Test | Participant Test | Non-Participant Test |
|---|---|---|---|---|
| Appliances | 0.86 | 1.73 | 4.06 | 0.34 |
| Assistive Technologies | - | - | N/A | - |
| Compressed Air | 0.56 | 0.73 | 3.96 | 0.33 |
| Controls | 0.87 | 0.73 | 3.74 | 0.33 |
| HVAC | 0.83 | 1.20 | 7.49 | 0.32 |
| Industrial Process | 0.08 | 0.08 | (8.01) | 0.07 |
| Lighting | 1.75 | 1.51 | 6.54 | 0.35 |
| Monitoring | - | - | N/A | - |
| Motors | - | - | N/A | - |
| New Tech | 1.42 | 1.14 | 2.56 | 0.39 |
| Renewables | N/A | N/A | N/A | N/A |
| Resource Management | 1.29 | 1.29 | N/A | 0.29 |
| Shell | (0.31) | (1.11) | (0.77) | (0.12) |
| Sustainable Building | - | - | N/A | - |
| **PORTFOLIO** | **1.11** | **1.11** | **4.46** | **0.33** |

NOTES:

Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.
Costs associated with membership in NEEA are excluded from all cost-effectiveness calculations.
Costs associated with outstanding leases are excluded from all cost-effectiveness calculations.
"N/A" is listed for segments and technologies with benefits, but no costs.

Table 11 **Net Benefits by Customer Segment**

| | Total Resource Cost Test | Utility Cost Test | Participant Test | Non-Participant Test |
|---|---|---|---|---|
| Agriculture | $ (30,784) | $ (30,784) | $ - | $ (30,784) |
| Education | $ 958,778 | $ 347,818 | $ 2,417,921 | $ (1,448,409) |
| Food Service | $ (32,371) | $ (20,798) | $ 98,941 | $ (130,319) |
| Health Care | $ 97,913 | $ (67,544) | $ 236,051 | $ (138,138) |
| Hospitality | $ 9,879 | $ (92,295) | $ 219,638 | $ (210,100) |
| Limited Income | $ (46,251) | $ (46,251) | $ 1,276,036 | $ (1,445,800) |
| Manufacturing | $ (634,407) | $ (99,250) | $ (52,563) | $ (581,963) |
| Office | $ 81,059 | $ (67,195) | $ 320,826 | $ (274,598) |
| Residential | $ (40,061) | $ 340,559 | $ 827,902 | $ (1,103,064) |
| Retail | $ 38,408 | $ (40,457) | $ 177,215 | $ (140,418) |
| **PORTFOLIO** | **$ 402,162** | **$ 223,803** | **$ 5,521,968** | **$ (5,503,595)** |

Table 12 **Net Benefits by Technology**

| | Total Resource Cost Test | Utility Cost Test | Participant Test | Non-Participant Test |
|---|---|---|---|---|
| Appliances | $ (39,944) | $ 105,571 | $ 444,788 | $ (583,667) |
| Assistive Technologies | $ (104,694) | $ (104,694) | $ - | $ (104,694) |
| Compressed Air | $ (16,586) | $ (7,881) | $ 25,756 | $ (42,341) |
| Controls | $ (39,177) | $ 3,781 | $ 333,908 | $ (365,394) |
| HVAC | $ (146,462) | $ 113,941 | $ 1,689,879 | $ (2,093,761) |
| Industrial Process | $ (29,492) | $ (30,249) | $ 6,817 | $ (36,309) |
| Lighting | $ 612,692 | $ 236,186 | $ 1,941,179 | $ (1,342,545) |
| Monitoring | $ (24,023) | $ (24,023) | $ - | $ (24,023) |
| Motors | $ (59,413) | $ (59,413) | $ - | $ (59,413) |
| New Tech | $ 394,861 | $ 45,380 | $ 969,313 | $ (574,515) |
| Renewables | $ - | $ - | $ - | $ - |
| Resource Management | $ 28,527 | $ 28,527 | $ 270,812 | $ (229,678) |
| Shell | $ (165,112) | $ (74,309) | $ (160,482) | $ (38,240) |
| Sustainable Building | $ (9,015) | $ (9,015) | $ - | $ (9,015) |
| **PORTFOLIO** | **$ 402,162** | **$ 223,803** | **$ 5,521,968** | **$ (5,503,595)** |

**NOTES:**

Net benefits are calculated by subtracting costs from benefits.
Costs and benefits included in each cost-effectiveness test are detailed in Table 13.
Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.
Costs associated with membership in NEEA are excluded from all cost-effectiveness calculations.
Costs associated with outstanding leases are excluded from all cost-effectiveness calculations.

Table 13 Summary of Cost-Effectiveness Tests and Descriptive Statistics

| Total Resource Cost Test | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| Electric avoided cost | $ 2,066,877 | $ 599,880 | $ 2,666,757 |
| Non-Energy benefits | $ 1,775,461 | $ - | $ 1,775,461 |
| Natural Gas avoided cost | $ (209,832) | $ (136,413) | $ (346,244) |
| TRC benefits | $ 3,632,506 | $ 463,467 | $ 4,095,973 |
| Non-incentive utility cost | $ 1,080,782 | $ 95,227 | $ 1,176,009 |
| Customer cost | $ 2,103,311 | $ 414,492 | $ 2,517,802 |
| TRC costs | $ 3,184,093 | $ 509,718 | $ 3,693,811 |
| TRC ratio | 1.14 | 0.91 | 1.11 |
| Net TRC benefits | $ 448,413 | $ (46,251) | $ 402,162 |

| Utility Cost Test | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| Electric avoided cost | $ 2,066,877 | $ 599,880 | $ 2,666,757 |
| Natural Gas avoided cost | $ (209,832) | $ (136,413) | $ (346,244) |
| UCT benefits | $ 1,857,045 | $ 463,467 | $ 2,320,512 |
| Non-incentive utility cost | $ 1,080,782 | $ 95,227 | $ 1,176,009 |
| Incentive cost | $ 506,209 | $ 414,492 | $ 920,701 |
| UCT costs | $ 1,586,991 | $ 509,718 | $ 2,096,709 |
| UCT ratio | 1.17 | 0.91 | 1.11 |
| Net UCT benefits | $ 270,054 | $ (46,251) | $ 223,803 |

| Participant Test | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| Bill Reduction | $ 4,067,573 | $ 1,276,036 | $ 5,343,609 |
| Non-Energy benefits | $ 1,775,461 | $ - | $ 1,775,461 |
| Participant benefits | $ 5,843,033 | $ 1,276,036 | $ 7,119,070 |
| Customer project cost | $ 2,103,311 | $ 414,492 | $ 2,517,802 |
| Incentive received | $ 506,209 | $ 414,492 | $ 920,701 |
| Participant costs | $ 1,597,101 | $ - | $ 1,597,101 |
| Participant Test ratio | 3.66 | N/A | 4.46 |
| Net Participant benefits | $ 4,245,932 | $ 1,276,036 | $ 5,521,968 |

| Non-Participant Test | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| Electric avoided cost savings | $ 2,066,877 | $ 599,880 | $ 2,666,757 |
| Non-Part benefits | $ 2,066,877 | $ 599,880 | $ 2,666,757 |
| Revenue loss | $ 4,537,681 | $ 1,535,961 | $ 6,073,642 |
| Non-incentive utility cost | $ 1,080,782 | $ 95,227 | $ 1,176,009 |
| Customer incentives | $ 506,209 | $ 414,492 | $ 920,701 |
| Non-Part costs | $ 6,124,672 | $ 2,045,679 | $ 8,170,351 |
| Non-Part. ratio | 0.34 | 0.29 | 0.33 |
| Net Non-Part. benefits | $ (4,057,795) | $ (1,445,800) | $ (5,503,595) |

| Descriptive Statistics | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| Annual kWh savings | 10,363,237 | 1,957,034 | 12,320,271 |
| Customer cost/kWh | $ 0.20 | $ 0.21 | $ 0.20 |
| Non-incentive utility cost/kWh | $ 0.10 | $ 0.05 | $ 0.10 |
| Electric avoided cost/kWh | $ 0.20 | $ 0.31 | $ 0.22 |
| Incentive cost/kWh | $ 0.05 | $ 0.21 | $ 0.07 |

**NOTES:**

Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.
Costs associated with membership in NEEA are excluded from all cost-effectiveness calculations.
Costs associated with outstanding leases are excluded from all cost-effectiveness calculations.
"N/A" is listed for segments and technologies with benefits, but no costs.

# Energy Efficiency Tariff Rider Balance Calculations

The methodology of this calculation has not changed since the previous Triple-E Report. One error, the omission of the effect of the one-month lag specified in the 1994 Accounting Guidelines amounting to $10,949, has been corrected.

In the last twelve months Avista has:

- spent $2.2 million more than it has collected as Tariff Rider revenues ($1.4 million in Washington, $0.8 million in Idaho)
- incurred expenditures in excess of rider revenues by 47% (41% in Washington, 64% in Idaho)
- reduced the Tariff Rider balance by $1.9 million ($1.2 million in Washington, $0.7 million in Idaho)
- cut the balance by 45% (41% in Washington, 53% in Idaho) and
- incorporated within the balance $318,000 of interest assessments ($215,000 Washington, $103,000 Idaho).

This progress towards Avista Corporation's objective of reducing the balance through funding cost-effective energy efficiency may somewhat overstate the progress to date due to a disproportionate amount of NEEA invoices paid during this moving average. However, even taking this into consideration, it does represent a significant increase in energy efficiency activity on the part of the Company.

The TRC cost-effectiveness during this trimester indicates that it is not only an increase in expenditures, but that the incremental expenditures do have energy savings commensurate with their costs.

Refer to *Table 14* for the most recent update to our tariff rider balance calculation.

Table 14

## Calculation of Energy Efficiency Tariff Rider Balance and Interest

| Month | Washington DSM Expenditures | Washington DSM Revenues | Washington Beginning DSM balance | Washington Ending DSM balance | Washington Interest | Washington Ending bal. with interest |
|---|---|---|---|---|---|---|
| January 1999 | $ 171,037 | $ 371,658 | $ 2,617,016 | $ 2,817,637 | $ 10,950 | $ 2,828,586 |
| February | $ 188,863 | $ 321,493 | $ 2,828,586 | $ 2,961,216 | $ 21,668 | $ 2,982,885 |
| March | $ 416,803 | $ 292,771 | $ 2,982,885 | $ 2,858,853 | $ 23,084 | $ 2,881,937 |
| April | $ 781,855 | $ 266,606 | $ 2,881,937 | $ 2,366,688 | $ 23,291 | $ 2,389,979 |
| May | $ 333,268 | $ 247,454 | $ 2,389,979 | $ 2,304,165 | $ 20,927 | $ 2,325,092 |
| June | $ 283,079 | $ 266,981 | $ 2,325,092 | $ 2,308,994 | $ 18,716 | $ 2,327,710 |
| July | $ 315,854 | $ 237,115 | $ 2,327,710 | $ 2,248,971 | $ 18,476 | $ 2,267,447 |
| August | $ 470,627 | $ 272,035 | $ 2,267,447 | $ 2,068,855 | $ 18,248 | $ 2,087,102 |
| September | $ 220,534 | $ 302,045 | $ 2,087,102 | $ 2,168,613 | $ 17,289 | $ 2,185,903 |
| October | $ 333,763 | $ 260,080 | $ 2,185,903 | $ 2,112,220 | $ 16,968 | $ 2,129,188 |
| November | $ 174,943 | $ 263,916 | $ 2,129,188 | $ 2,218,161 | $ 17,137 | $ 2,235,298 |
| December | $ 759,356 | $ 317,111 | $ 2,235,298 | $ 1,793,053 | $ 17,333 | $ 1,810,386 |
| January 2000 | $ 261,424 | $ 350,395 | $ 1,810,386 | $ 1,899,357 | $ 16,061 | $ 1,915,419 |
| February | $ 296,815 | $ 318,411 | $ 1,915,419 | $ 1,937,014 | $ 14,791 | $ 1,951,805 |
| March | $ 566,151 | $ 296,857 | $ 1,951,805 | $ 1,682,511 | $ 15,360 | $ 1,697,871 |
| 1999 totals | $ 4,449,983 | $ 3,419,265 | | | $ 224,088 | |
| 2000 totals | $ 1,124,390 | $ 965,663 | | | $ 46,212 | |

| Month | Idaho DSM Expenditures | Idaho DSM Revenues | Idaho Beginning DSM balance | Idaho Ending DSM balance | Idaho Interest | Idaho Ending bal. with interest |
|---|---|---|---|---|---|---|
| January 1999 | $ 70,147 | $ 161,905 | $ 1,053,579 | $ 1,145,337 | $ 2,385 | $ 1,147,722 |
| February | $ 100,620 | $ 157,171 | $ 1,147,722 | $ 1,204,273 | $ 8,767 | $ 1,213,040 |
| March | $ 57,166 | $ 143,563 | $ 1,213,040 | $ 1,299,438 | $ 9,378 | $ 1,308,815 |
| April | $ 268,935 | $ 132,749 | $ 1,308,815 | $ 1,172,629 | $ 10,017 | $ 1,182,647 |
| May | $ 131,689 | $ 121,686 | $ 1,182,647 | $ 1,172,644 | $ 9,894 | $ 1,182,538 |
| June | $ 87,749 | $ 121,986 | $ 1,182,538 | $ 1,216,775 | $ 9,391 | $ 1,226,165 |
| July | $ 82,662 | $ 121,018 | $ 1,226,165 | $ 1,264,521 | $ 9,566 | $ 1,274,087 |
| August | $ 146,099 | $ 82,983 | $ 1,274,087 | $ 1,210,971 | $ 9,931 | $ 1,220,902 |
| September | $ 85,885 | $ 86,004 | $ 1,220,902 | $ 1,221,021 | $ 9,908 | $ 1,230,929 |
| October | $ 304,545 | $ 81,571 | $ 1,230,929 | $ 1,007,955 | $ 9,736 | $ 1,017,691 |
| November | $ 167,877 | $ 85,391 | $ 1,017,691 | $ 935,206 | $ 8,927 | $ 944,132 |
| December | $ 306,838 | $ 102,257 | $ 944,132 | $ 739,552 | $ 7,786 | $ 747,338 |
| January 2000 | $ 174,092 | $ 93,727 | $ 747,338 | $ 666,973 | $ 6,713 | $ 673,686 |
| February | $ 92,648 | $ 124,369 | $ 673,686 | $ 705,407 | $ 5,639 | $ 711,046 |
| March | $ 200,639 | $ 95,373 | $ 711,046 | $ 605,780 | $ 5,499 | $ 611,278 |
| 1999 totals | $ 1,810,210 | $ 1,398,284 | | | $ 105,685 | |
| 2000 totals | $ 467,379 | $ 313,469 | | | $ 17,850 | |

| Month | Combined DSM Expenditures | Combined DSM Revenues | Combined Beginning DSM balance | Combined Ending DSM balance | Combined Interest | Combined Ending bal. with interest |
|---|---|---|---|---|---|---|
| January 1999 | $ 241,185 | $ 533,563 | $ 3,670,595 | $ 3,962,973 | $ 13,335 | $ 3,976,308 |
| February | $ 289,483 | $ 478,664 | $ 3,976,308 | $ 4,165,489 | $ 30,436 | $ 4,195,925 |
| March | $ 473,969 | $ 436,334 | $ 4,195,925 | $ 4,158,290 | $ 32,462 | $ 4,190,752 |
| April | $ 1,050,790 | $ 399,355 | $ 4,190,752 | $ 3,539,317 | $ 33,309 | $ 3,572,626 |
| May | $ 464,956 | $ 369,140 | $ 3,572,626 | $ 3,476,809 | $ 30,820 | $ 3,507,630 |
| June | $ 370,828 | $ 388,967 | $ 3,507,630 | $ 3,525,768 | $ 28,107 | $ 3,553,875 |
| July | $ 398,516 | $ 358,133 | $ 3,553,875 | $ 3,513,492 | $ 28,043 | $ 3,541,534 |
| August | $ 616,726 | $ 355,018 | $ 3,541,534 | $ 3,279,826 | $ 28,178 | $ 3,308,004 |
| September | $ 306,419 | $ 388,049 | $ 3,308,004 | $ 3,389,635 | $ 27,197 | $ 3,416,832 |
| October | $ 638,308 | $ 341,651 | $ 3,416,832 | $ 3,120,175 | $ 26,704 | $ 3,146,879 |
| November | $ 342,820 | $ 349,307 | $ 3,146,879 | $ 3,153,366 | $ 26,064 | $ 3,179,430 |
| December | $ 1,066,194 | $ 419,368 | $ 3,179,430 | $ 2,532,604 | $ 25,120 | $ 2,557,724 |
| January 2000 | $ 435,516 | $ 444,122 | $ 2,557,724 | $ 2,566,330 | $ 22,774 | $ 2,589,105 |
| February | $ 389,463 | $ 442,780 | $ 2,589,105 | $ 2,642,421 | $ 20,430 | $ 2,662,851 |
| March | $ 766,790 | $ 392,230 | $ 2,662,851 | $ 2,288,291 | $ 20,858 | $ 2,309,150 |
| 1999 totals | $ 6,260,193 | $ 4,817,549 | | | $ 329,773 | |
| 2000 YTD totals | $ 1,591,769 | $ 1,279,132 | | | $ 64,063 | |

**DSM balance reduction in most recent twelve months:**

| | Rev - Exp | Exp / Rev | $ balance reduction | % balance reduction | Interest |
|---|---|---|---|---|---|
| Washington | $ (1,398,663) | 141% | $ 1,184,066 | 41% | $ 214,597 |
| Idaho | $ (800,543) | 164% | $ 697,537 | 53% | $ 103,006 |
| System | $ (2,199,206) | 147% | $ 1,881,602 | 45% | $ 317,603 |

**NOTES:**

Interest calculations have been revised to be based upon the prior months balances, per the one month lag incorporated into the filed accounting guidelines.
January interest reflects the adjustment to annual 1995 to 1998 balances to reflect this one month lag.

# Analysis / Measurement and Evaluation Summary

For this reporting period, seven projects and programs were selected for in-depth review. The following summaries highlight the findings of each review.

For confidentiality reasons, customer names have been omitted except in the case of governmental organizations. More detailed reports are available upon request.

The analysis team continually endeavors to present to the Triple-E Board an accurate portrayal of Avista Utilities' energy efficiency activities. Comments and suggestions regarding both the content and format of this report are always welcome.

## Program Updates

### Resource Management Partnership Program (RMPP)

The billing analysis of all school districts participating in RMPP were reviewed and revised to meet the most recent policy decisions on these calculations.

It was notable that no non-energy benefits have been identified during the trimester. Follow-up indicated that this was an accurate reflection of the programs current activity. Most of the participating school districts have already realized the majority of the cost-effective non-energy resource savings.

One meter located at Mead High School is currently under investigation. The usage on the meter has dramatically increased to a level far beyond that which is reasonable for the tennis court application that it was intended for. We are almost certain that the nearby construction of a major addition to the school is the cause of the aberration. If we can positively identify construction as the source of the usage we will revise the billed savings calculation upward by that amount.

### *VendingMI$ER*™ Program

In the November 1999 Triple-E Report, it was reported that Avista was embarking on an aggressive project to install *VendingMI$ER* control units on hundreds of cold drink vending machines within the service territory. As of March 31, 2000, over 300 individual *VendingMI$ER* units were installed, or in the process of being installed, on vending machines throughout Avista Utilities' service territory.

The *VendingMI$ER* control unit is manufactured by Bayview Technology Group, Inc. It is designed to operate as an intelligent power controller for cold product vending machines. It is not recommended for use with vending machines containing perishable products. The *VendingMI$ER* uses a passive infrared sensor to shut down the controlled vending machine when the area surrounding the machine has been vacant for 15 minutes. The *VendingMI$ER* will periodically re-power the vending machine to ensure the product stays cold.

Preliminary monitoring conducted by Avista has shown an estimated annual energy savings of 1,500 kWh per unit. These results closely match studies performed by Bayview and other analysis, including a study performed by Rutgers University. These preliminary studies form the basis for the annual savings claim of 1,500 kWh per *VendingMI$ER* installation. Avista has adopted this figure for a prescriptive program, with the understanding that further data collection would occur and savings claims would be adjusted accordingly.

The *VendingMI$ER* is appropriately considered a new technology since a microprocessor based control of vending machines is new and such a technology was non-existent in the Avista service territory prior to the launch of this program. Under the existing tariff, any new technology project producing 1,500 kWh in annual savings would be eligible for an incentive of $150.00 to $210.00,depending on the project simple payback. For this program Avista has chosen to purchase *VendingMI$ER* units on behalf of customers, in lieu of direct financial incentives. The cost per *VendingMI$ER* unit is $135.

Avista Utilities is currently in the midst of extensive monitoring of the *VendingMI$ER* control unit. Data acquisition began in December of 1999. Monitoring is currently being performed on dozens of cold drink vending machines at customer locations throughout the service territory. Datalogging of vending machines without control units installed, as well as those under *VendingMI$ER* control, are underway. Data acquisition will continue until a large enough population has been observed to provide us with adequate data for calculation of average annual kWh savings. Datalogging results will be used to adjust annual energy savings claimed by Energy Services if necessary.

The results of datalogging efforts for the *VendingMI$ER* program thus far have indicated that the savings may average closer to 800 kWh per installation. However, given the substantial variance of savings across projects we have decided to delay any adjustment until we can expand the sample size. We will revisit this topic in the next Triple-E Report, with the benefits of a larger sample size.

The analysis team intends to capture data on individual electricity consumption for as long as a year, both pre and post installation. We are also striving to capture energy consumption on a variety of vending machine makes and models, dispensing cold products of various sizes and in a variety of locations.

## Individual Project Reviews

| | |
|---|---|
| **Project Status:** | Completed August of 1999 |
| **Program/Segment:** | Trade Ally and New Technology Programs |
| **Technology:** | Canopy Lighting and LED Strip Lighting |
| **Site:** | Service Station and Convenience Store |
| **Location:** | Colville, Washington |

<u>Study Summary</u>

- This study resulted in no impact on energy savings estimates.
- This project was randomly selected from a list of projects completed between January 1, 1999 and February 15, 2000.
- The project involved the lighting retrofits incorporated in the replacement of canopies over gas pump islands. High wattage metal halide lights were replaced with lower wattage metal halide light fixtures with some de-lamping. High wattage fluorescent lights were replaced with new technology light emitting diode (LED) strips.
- After some investigation, the LED strip lighting was found to be appropriately incentivized as a New Technology measure. It has been recommended that Energy Services attached

documentation to New Technology projects to explain the rationale used to determine New Technology status.

- A process error was uncovered as the LED canopy strip lighting was mistakenly entered into the project tracking database as "LED Exit Signs."

Study Detail

This project was initiated after an energy audit of the customer's facility. The energy audit was completed in September of 1998. The customer was in the process of replacing canopies over three gasoline and diesel pump islands and chose to install lower wattage metal halide fixtures. The manufacturer of the new fixtures claims several design improvements allow the use of a lower wattage lamps. The new fixture positions the metal halide lamp vertically rather than horizontally, and uses an improved reflector and prismatic lens to direct light out of the fixture in a uniform manner.

Lighting improvements were incentivized under the Trade Ally program in effect at the time. As the project neared completion, the Energy Services project lead separated the Light Emitting Diode strip lighting savings from the remainder of the project. This allowed the LED portion of the project to be incentivized as a New Technology.

After a review of the project file and discussion with the Energy Services project technical lead, it was determined that New Technologies incentives were appropriately applied toward the LED strip lighting as this was a relatively new product and this was the first application with Avista involvement. Initially the project file lacked documentation, which would explain the rationale behind assigning New Technology status to the LED strip lighting. This deficiency was brought to the attention of Energy Services and additional notes were added to the project file. Analysis staff recommended Energy Services incorporate such documentation with all New Technology projects. As a result, a policy change has been incorporated.

A review of the accounting transactions revealed an error in data entry. The LED canopy strip lighting was mistakenly entered into the Energy Services database as an LED exit sign project. The error caused incentive payments to be charged to the LED exit sign program account. Annual kWh savings were also erroneously credited to the LED exit sign program. Energy Services was informed of the error and appropriate account corrections were made.

A post-verification of the installation was performed by Energy Services and photographs of the equipment were included in the project file. The analysis team also performed an independent verification of this project. The engineering calculations were reviewed and found to be accurate.

Energy savings for this project totaled 12,800 kWh per year for the metal halide canopy lighting improvements and 8,340 kWh per year for the LED strip lighting. The customer received an incentive of $1,084.00.

| | |
|---|---|
| **Project Status:** | Completed January of 1999 |
| **Program/Segment:** | Site Specific Program |
| **Technology:** | Irrigation Pumping Efficiency Improvements |
| **Site:** | Farm |
| **Location** | Kahlotus, Washington |

Study Summary

- This study resulted in no impact on energy savings estimates.

- This project was randomly selected from a list of projects completed between January 1, 1999 and February 15, 2000.
- The project involved the installation of a variable frequency drive on a irrigation pump motor and a retrofit from standard impact sprinkler heads to low pressure pivot rotator sprinkler heads. The project was completed under a performance-based agreement.
- Data was collected for over a year from water flow meters and Avista Utilities electric meters on irrigation pumps serving seven pivot irrigation systems. The results of the data collection analyses were used to establish energy and water savings, and the incentive amount.
- Several non-energy benefits were documented by the owners of the farm; including improved cold weather irrigation to provide a measure of frost protection, a large reduction in water usage, and reduced equipment failure caused by high water pressure stress.

Study Detail

In the summer of 1997, a study was begun at a family owned farm near Kahlotus, Washington. The farmers of this land were seeking assistance to reduce both electric power consumption and water usage.

The customer and the Energy Services technical lead chose to replace standard impact sprinkler heads with a low-pressure pivot rotator sprinkler heads. To allow proper operation and control of the new sprinklers, water pressure control was required. The pressure control was obtained by installing a variable frequency drive on a 100 horsepower pump serving the seven irrigated crop circles.

The sprinkler heads provided several benefits; including reduced water run off, greater uniformity in water application, reduced wind drift, and reduced water loss caused by evaporation. The new sprinkler heads also allowed the farmer to vary the water droplet size, allowing improved precision in water application.

The operators of the farm closely monitored water usage over several years. Electric usage history was available from Avista Utilities customer records. With this information, a performance-based energy efficiency agreement was executed. Avista and the farm operators collected water flow data and electric usage data for over one year following the installation of the low-pressure pivot rotator sprinkler heads and the variable frequency drive. The data collection was completed in December of 1998.

Several non-energy benefits were documented. Water savings totaled 554 acre-feet per year (180,521,454 gallons). Superior water distribution capabilities allowed the farm to provide a measure of frost protection. The customer anticipates significant maintenance cost savings from reduced equipment failure caused by high water pressure. The customer also expressed satisfaction with the improved water distribution on his crops, noting that "The crop under the rotator equipped center pivots was always in at least as good, or in better condition, than the crops grown under impact sprinkler equipped machines."

A review of the incentive formula in the energy efficiency agreement found that the incentive calculation was appropriately applied. A review of the accounting transactions found costs and incentives were appropriately charged to the Site Specific program.

The savings for this project totaled 51,326 kWh per year. The customer received an incentive of $2,566.00.

**Project Status:** Completed May of 1999
**Program/Segment:** Trade Ally and Site Specific Programs
**Technology:** Cooling and Ventilation Improvements
**Site:** Mine
**Location:** Wallace, Idaho

Study Summary

- This study resulted in no impact on energy savings estimates.
- This project was randomly selected from a list of projects completed between January 1, 1999 and February 15, 2000.
- The project was completed using both the Trade Ally program and the Site Specific program. The Trade Ally portion allowed for expenditures to study and implement the replacement of *Whizbang* units with portable fans. The Site Specific program provided incentives for the conversion of an adjacent mineshaft into an exhaust shaft.
- The large scale and unique nature of these projects warrant an ongoing persistence study. The large annual energy savings could be reduced should the mine scale back its operations in the future.

Study Detail

Heat and humidity levels in the mineshafts are very high. The miners in the shafts developed a device called a *Whizbang* to provide cooling. A *Whizbang* is essentially a pipe, drilled with approximately a dozen 1/8" holes. The pipe is connected to a compressed air system and is turned on and off by the miners as needed. The study performed by Energy Services in coordination with the customer's own engineering staff indicated the mines had fifty *Whizbangs* operating up to 5,408 hours per year. While these devices worked well and were compatible with the extreme conditions found in the mines, they were created without regard to energy efficiency. Energy Services proposed replacing the *Whizbang* units with individual portable 2 horsepower cooling fans. The customer replaced the *Whizbangs*, on a limited basis, removing eighteen units and replacing them with two horsepower cooling fans.

The engineering estimates for the *Whizbang* replacements were reviewed and found to be appropriate. However, the customer is under no obligation to continue the use of the individual fans, nor does there appear to be a tracking mechanism in place to ensure that the air compressor loads are reduced. Analysis staff recommended Energy Services coordinate a follow-up study within the next six months to measure the persistence of this measure.

The ventilation project required that the mine open a connection to an adjacent shaft and use it for exhaust ventilation. By making the connection to the adjacent shaft, ventilation to the mine was increased and fan horsepower requirements were reduced.

Information included in the project file indicates a significant engineering effort was made to ensure this operational change would greatly improve the ventilation in the mine and reduce the required horsepower. Engineering calculations are detailed in an initial project memo from the Avista project engineer, however the project changed over time and subsequent calculations were absent in the project file. Final savings figures were presented only in a summary spreadsheet and to recreate the final energy savings figures was difficult.
Analysis staff recommended Energy Services review project files upon project completion and establish a procedure to ensure final energy savings calculations are clearly documented and reflect all changes between initial study and project completion.

As with the *Whizbang* project, any change in the mine's operation could dramatically alter the energy savings provided by the ventilation project. A follow-up study of both of these projects, by the analysis team in coordination with Energy Services, is to be initiated within the next six months.

The savings for the *Whizbang* cooling replacement project totaled 2,091,300 kWh per year and savings for the ventilation efficiency improvements totaled 1,942,100 kWh per year. The customer received an incentive (capped at 50% of the project cost) of $62,500.00.

| | |
|---|---|
| **Project Status:** | Contracted as of March 31, 2000 |
| **Program/Segment:** | Site Specific Program / Manufacturing Segment |
| **Technology:** | Process Fuel Conversion |
| **Site:** | Specialty Metals Manufacturer |
| **Location** | Spokane, Washington |

<u>Study Summary</u>

- This study resulted in no impact on energy savings estimates.
- This project was randomly selected from a list of projects which were in progress as of March 31, 2000.
- This project was listed as Contracted as of March 31, 2000 and involves a process fuel switch. An electric oven is to be replaced with a natural gas oven.
- The project file contained a detailed engineering calculation to estimate potential electricity savings.
- A significant non-energy benefit was identified early in the study. The customer is nearing the maximum capacity of existing transformers. The process fuel switch will allow the customer to defer the installation of a new transformer and additional electrical circuit breakers and will free up approximately 40 kW of capacity to be used for future production expansion.
- The process requires precise temperature control and requires specialized ovens.

<u>Study Detail</u>

The manufacturing process, which is the subject of this project, involves the bonding of dissimilar metals. In this case, steel is bonded to aluminum using a molecular bonding material. The bond occurs as the steel and aluminum are heated in an oven with precise temperature control. The customer's process allows bonding to occur without reduction or oxidation, which often occur when dissimilar metals are in close proximity.

For this energy efficiency project, the customer will be replacing an existing radiant electric oven with a new radiant natural gas oven. The customer also needed to increase processing capacity and was considering several options including the installation of additional electric or gas fired ovens. The new gas oven chosen by the customer will provide this increase in the production capacity.

Energy Services personnel documented the operation of the existing electric oven and detailed the operation of up to two additional electric ovens under consideration to meet the increased process capacity. Using production information provided by the customer, it was calculated that the heating elements in the original oven consumed 166,400 kWh per year. Adding two similar

**Table B3** **Allocation of Utility Costs Across Customer Segments and Technologies**

| | Appliance | Assistive Tech | Controls | Motors | HVAC | Industrial | Lighting | Maintenance | Monitoring | New Tech | Regional | Renewable | Resource Mgmt | Shell | Sustainable building | Total $ | % of portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NEEA | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 260,151 | $ - | $ - | $ - | $ - | $ 260,151 | 14.4% |
| Agriculture | $ - | $ - | $ 3,526 | $ 3,526 | $ - | $ 3,526 | $ - | $ - | $ 1,175 | $ - | $ - | $ - | $ - | $ - | $ - | $ 11,755 | 0.6% |
| Manufacturing | $ - | $ - | $ 35,833 | $ 35,833 | $ 35,833 | $ 233,078 | $ 28,845 | $ 17,917 | $ 35,833 | $ 35,833 | $ 35,833 | $ - | $ - | $ - | $ - | $ 494,838 | 27.3% |
| Health Care | $ - | $ - | $ 6,081 | $ 3,040 | $ 9,121 | $ 3,040 | $ 12,383 | $ 6,081 | $ 3,040 | $ 3,040 | $ - | $ 3,040 | $ 6,081 | $ 3,040 | $ - | $ 57,989 | 3.2% |
| Hospitality | $ 5,461 | $ - | $ 16,383 | $ 5,461 | $ 5,461 | $ - | $ 17,241 | $ 5,461 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 55,466 | 3.1% |
| Office | $ - | $ - | $ 19,693 | $ 9,846 | $ 22,453 | $ - | $ 41,821 | $ 9,846 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 103,660 | 5.7% |
| Food Service | $ - | $ - | $ 42,027 | $ - | $ - | $ - | $ 42,147 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 84,174 | 4.7% |
| Retail | $ - | $ - | $ 17,937 | $ - | $ - | $ - | $ 43,893 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 61,830 | 3.4% |
| Residential | $ - | $ 19,791 | $ - | $ - | $ 66 | $ - | $ 1,520 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 21,377 | 1.2% |
| Limited Income (electric) | $ - | $ - | $ - | $ - | $ 296,485 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 23,870 | $ 591 | $ 320,946 | 17.7% |
| RMPP / Education | $ - | $ - | $ 55,241 | $ - | $ 50,100 | $ - | $ 198,413 | $ - | $ - | $ 34,147 | $ - | $ - | $ - | $ - | $ - | $ 337,901 | 18.7% |
| Total | $ 5,461 | $ 19,791 | $ 196,721 | $ 57,707 | $ 419,519 | $ 239,645 | $ 386,263 | $ 39,305 | $ 40,049 | $ 73,020 | $ 295,984 | $ 3,040 | $ 6,081 | $ 26,910 | $ 591 | $ 1,810,088 | 100.0% |
| % of portfolio | 0.3% | 1.1% | 10.9% | 3.2% | 23.2% | 13.2% | 21.3% | 2.2% | 2.2% | 4.0% | 16.4% | 0.2% | 0.3% | 1.5% | 0.0% | 100.0% | |

NOTE: This is a compilation of all utility costs, including incentives, by customer segment and technology.

REFERENCE: Comparable to *Table 3* of March 2000 Report.

Table B4

## Allocation of Direct Incentives Across Customer Segments and Technologies

| | Appliance | Assistive Tech | Controls | Motors | HVAC | Industrial | Lighting | Maintenance | Monitoring | New Tech | Regional | Renewable | Resource Mgmt | Shell | Sustainable building | Total $ | % of portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Regional | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (1,188) | $ - | $ - | $ - | $ - | $ (1,188) | -0.2% |
| Agriculture | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | 0.0% |
| Manufacturing | $ - | $ - | $ - | $ - | $ - | $ 179,328 | $ 10,928 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 190,256 | 31.0% |
| Health Care | $ - | $ - | $ - | $ - | $ - | $ - | $ 3,262 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 3,262 | 0.5% |
| Hospitality | $ - | $ - | $ - | $ - | $ - | $ - | $ 858 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 858 | 0.1% |
| Office | $ - | $ - | $ - | $ - | $ 2,760 | $ - | $ 12,282 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 15,042 | 2.5% |
| Food Service | $ - | $ - | $ - | $ - | $ - | $ - | $ 120 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 120 | 0.0% |
| Retail | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,040 | -$ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,040 | 0.3% |
| Residential | $ - | $ 114 | $ - | $ - | $ 66 | $ - | $ 1,520 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,700 | 0.3% |
| Limited Income | $ - | $ - | $ - | $ - | $ 267,507 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 23,870 | $ - | $ 291,377 | 47.5% |
| Education | $ - | $ - | $ 21,095 | $ - | $ 15,953 | $ - | $ 73,208 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 110,256 | 18.0% |
| TOTAL | $ - | $ 114 | $ 21,095 | $ - | $ 286,286 | $ 179,328 | $ 104,218 | $ - | $ - | $ - | $ (1,188) | $ - | $ - | $ 23,870 | $ - | $ 613,723 | 100.0% |
| % of portfolio | 0.0% | 0.0% | 3.4% | 0.0% | 46.6% | 29.2% | 17.0% | 0.0% | 0.0% | 0.0% | -0.2% | 0.0% | 0.0% | 3.9% | 0.0% | 100.0% | |

REFERENCE: Comparable to *Table 4* of March 2000 Report.

**Table B4** **Allocation of Direct Incentives Across Customer Segments and Technologies**

| | Appliance | Assistive Tech | Controls | Motors | HVAC | Industrial | Lighting | Maintenance | Monitoring | New Tech | Regional | Renewable | Resource Mgmt | Shell | Sustainable building | Total $ | % of portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Regional | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (1,188) | $ - | $ - | $ - | $ - | $ (1,188) | -0.2% |
| Agriculture | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | 0.0% |
| Manufacturing | $ - | $ - | $ - | $ - | $ - | $ 179,328 | $ 10,928 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 190,256 | 31.0% |
| Health Care | $ - | $ - | $ - | $ - | $ - | $ - | $ 3,262 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 3,262 | 0.5% |
| Hospitality | $ - | $ - | $ - | $ - | $ - | $ - | $ 858 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 858 | 0.1% |
| Office | $ - | $ - | $ - | $ - | $ 2,760 | $ - | $ 12,282 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 15,042 | 2.5% |
| Food Service | $ - | $ - | $ - | $ - | $ - | $ - | $ 120 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 120 | 0.0% |
| Retail | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,040 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,040 | 0.3% |
| Residential | $ - | $ 114 | $ - | $ - | $ 66 | $ - | $ 1,520 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,700 | 0.3% |
| Limited Income | $ - | $ - | $ - | $ - | $ 267,507 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 23,870 | $ - | $ 291,377 | 47.5% |
| Education | $ - | $ - | $ 21,095 | $ - | $ 15,953 | $ - | $ 73,208 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 110,256 | 18.0% |
| TOTAL | $ - | $ 114 | $ 21,095 | $ - | $ 286,286 | $ 179,328 | $ 104,218 | $ - | $ - | $ - | $ (1,188) | $ - | $ - | $ 23,870 | $ - | $ 613,723 | 100.0% |
| % of portfolio | 0.0% | 0.0% | 3.4% | 0.0% | 46.6% | 29.2% | 17.0% | 0.0% | 0.0% | 0.0% | -0.2% | 0.0% | 0.0% | 3.9% | 0.0% | 100.0% | |

REFERENCE: Comparable to *Table 4* of March 2000 Report.

**Table B5** — Allocation of Electric Savings Across Customer Segments and Technologies

| | Appliance | Assistive Tech | Controls | Motors | HVAC | Industrial | Lighting | Maintenance | Monitoring | New Tech | Regional | Renewable | Resource Mgmt | Shell | Sustainable building | TOTAL | % of total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NEEA | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0% |
| Agriculture | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0% |
| Manufacturing | - | - | 561,150 | 8,841 | - | 889,907 | 220,054 | - | - | - | - | - | - | - | - | 1,677,952 | 11.8% |
| Health Care | - | - | - | - | 1,842,789 | - | 181,923 | - | - | - | - | - | - | - | - | 2,024,712 | 14.3% |
| Hospitality | - | - | - | - | - | - | 103,639 | - | - | - | - | - | - | 3,390 | - | 107,029 | 0.8% |
| Office | - | - | - | - | 43,789 | - | 96,209 | - | - | - | - | - | - | 97,334 | - | 237,332 | 1.7% |
| Food Service | - | - | - | - | - | - | 1,600 | - | - | - | - | - | - | - | - | 1,600 | 0.0% |
| Retail | - | - | - | - | - | - | 44,053 | - | - | - | - | - | - | - | - | 44,053 | 0.3% |
| Residential | - | - | - | - | 6,753,084 | - | 360,348 | - | - | 400 | - | - | - | - | - | 7,113,832 | 50.1% |
| Limited Income (electric) | - | - | - | - | 1,108,040 | - | - | - | - | - | - | - | - | 44,324 | - | 1,152,364 | 8.1% |
| RMPP / Education | - | - | 193,041 | 477,268 | 86,364 | - | 476,076 | - | - | - | - | - | 610,122 | - | - | 1,842,890 | 13.0% |
| TOTAL | - | - | 754,191 | 484,109 | 9,834,086 | 889,907 | 1,483,902 | - | - | 400 | - | - | 610,122 | 145,048 | - | 14,201,764 | |
| | 0.0% | 0.0% | 5.3% | 3.4% | 69.2% | 6.3% | 10.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.3% | 1.0% | 0.0% | | |

NOTE: These figures include de-rated electric savings from the Contracted and Construction phases.

REFERENCE: Comparable to *Table 5* of March 2000 Report.

**Table B6** — Allocation of Therm Savings Across Customer Segments and Technologies

| | Appliance | Assistive Tech | Controls | Motors | HVAC | Industrial | Lighting | Maintenance | Monitoring | New Tech | Regional | Renewable | Resource Mgmt | Shell | Sustainable building | TOTAL | % of total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NEEA | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0% |
| Agriculture | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0% |
| Manufacturing | - | - | - | - | - | (4,829) | (22) | - | - | - | - | - | - | - | - | (4,851) | 2.0% |
| Health Care | - | - | - | - | (43,214) | - | (2,418) | - | - | - | - | - | - | - | - | (45,632) | 18.3% |
| Hospitality | - | - | - | - | - | - | (185) | - | - | - | - | - | - | - | - | (185) | 0.1% |
| Office | - | - | - | - | 1,111 | - | (388) | - | - | - | - | - | - | 61,582 | - | 62,324 | -25.1% |
| Food Service | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0% |
| Retail | - | - | - | - | - | - | (12) | - | - | - | - | - | - | - | - | (12) | 0.0% |
| Residential | - | - | - | - | (288,103) | - | - | - | - | - | - | - | - | - | - | (288,103) | 115.8% |
| Limited Income (electric) | - | - | - | - | (18,779) | - | - | - | - | - | - | - | - | - | - | (18,779) | 7.6% |
| RMPP / Education | - | - | 28,893 | - | - | - | (3,106) | - | - | - | - | - | 22,726 | - | - | 46,513 | -18.7% |
| TOTAL | - | - | 28,893 | - | (348,985) | (4,829) | (6,110) | - | - | - | - | - | 22,726 | 61,582 | - | (248,724) | |
| | 0.0% | 0.0% | -10.8% | 0.0% | 140.3% | 1.9% | 2.5% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | -9.1% | -24.8% | 0.0% | | |

NOTE: These figures include de-rated therm savings from the Contracted and Construction phases.

REFERENCE: Comparable to *Table 6* of March 2000 Report.

**Table B7** **Cost-Effectiveness Statistics by Customer Segment**

| | Total Resource Cost Test | Utility Cost Test | Participant Test | Non-Participant Test |
|---|---|---|---|---|
| NEEA | - | - | - | - |
| Agriculture | - | - | | - |
| Manufacturing | 1.05 | 0.86 | | 0.40 |
| Health Care | 0.66 | 2.31 | 1.26 | 0.44 |
| Hospitality | 0.24 | 0.33 | 1.45 | 0.20 |
| Office | 2.27 | 2.52 | 10.85 | 0.63 |
| Food Service | 0.01 | 0.00 | | 0.00 |
| Retail | 0.12 | 0.13 | 2.26 | 0.10 |
| Residential | 1.51 | 78.15 | 2.16 | 0.48 |
| Limited Income (electric) | 1.23 | 1.23 | | 0.42 |
| RMPP / Education | 0.99 | 1.08 | 16.94 | 0.37 |
| PORTFOLIO | 1.04 | 1.84 | 2.98 | 0.43 |
| **PORTFOLIO w/o NEEA** | **1.12** | **2.11** | **2.98** | **0.44** |

REFERENCE: Comparable to *Table 9* of March 2000 Report.

**Table B8** **Cost-Effectiveness Statistics by Technology**

| | Total Resource Cost Test | Utility Cost Test | Participant Test | Non-Participant Test |
|---|---|---|---|---|
| Appliance | - | - | | - |
| Assistive Tech | - | - | | - |
| Controls | 0.60 | 1.14 | 1.34 | 0.43 |
| Motors | 2.58 | 1.63 | | 0.41 |
| HVAC | 1.18 | 4.63 | 2.12 | 0.47 |
| Industrial | 2.92 | 1.03 | | 0.45 |
| Lighting | 0.72 | 0.64 | | 0.28 |
| Maintenance | - | - | | - |
| Monitoring | - | - | | - |
| New Tech | 0.00 | 0.00 | | 0.00 |
| Regional | - | - | - | - |
| Renewable | - | - | | - |
| Resource Mgmt | 10.93 | 10.93 | | 0.47 |
| Shell | 2.75 | 7.66 | 3.32 | 0.79 |
| Sustainable Building | - | - | | - |
| PORTFOLIO | 1.04 | 1.84 | 2.98 | 0.43 |
| **PORTFOLIO w/o NEEA** | **1.12** | **2.11** | **2.98** | **0.44** |

REFERENCE: Comparable to *Table 10* of March 2000 Report.

Table B9 Summary of Cost-Effectiveness Tests and Descriptive Statistics

| Total Resource Cost Test | | Regular Income portfolio without NEEA | | Limited Income portfolio | | Overall portfolio without NEEA |
|---|---|---|---|---|---|---|
| Electric avoided cost | $ | 4,303,697 | $ | 457,790 | $ | 4,761,487 |
| Non-Energy benefits | $ | 76,850 | $ | - | $ | 76,850 |
| Natural Gas avoided cost | $ | (859,424) | $ | (63,443) | $ | (922,867) |
| TRC benefits | $ | 3,521,122 | $ | 394,347 | $ | 3,915,469 |
| Implementation cost | $ | 905,457 | $ | 29,569 | $ | 935,026 |
| Customer cost | $ | 2,273,339 | $ | 291,377 | $ | 2,564,716 |
| TRC costs | $ | 3,178,795 | $ | 320,946 | $ | 3,499,742 |
| TRC ratio | | 1.11 | | 1.23 | | 1.12 |

| Utility Cost Test | | Regular Income portfolio without NEEA | | Limited Income portfolio | | Overall portfolio without NEEA |
|---|---|---|---|---|---|---|
| Electric avoided cost | $ | 4,303,697 | $ | 457,790 | $ | 4,761,487 |
| Natural Gas avoided cost | $ | (859,424) | $ | (63,443) | $ | (922,867) |
| UCT benefits | $ | 3,444,273 | $ | 394,347 | $ | 3,838,620 |
| Implementation cost | $ | 905,457 | $ | 29,569 | $ | 935,026 |
| Incentive cost | $ | 595,293 | $ | 291,377 | $ | 886,670 |
| UCT costs | $ | 1,500,749 | $ | 320,946 | $ | 1,821,696 |
| UCT ratio | | 2.30 | | 1.23 | | 2.11 |

| Participant Test | | Regular Income portfolio without NEEA | | Limited Income portfolio | | Overall portfolio without NEEA |
|---|---|---|---|---|---|---|
| Bill Reduction | $ | 4,471,020 | $ | 456,505 | $ | 4,927,525 |
| Non-Energy benefits | $ | 76,850 | $ | - | $ | 76,850 |
| Participant benefits | $ | 4,547,869 | $ | 456,505 | $ | 5,004,374 |
| Customer project cost | $ | 2,273,339 | $ | 291,377 | $ | 2,564,716 |
| Incentive received | $ | (595,293) | $ | (291,377) | $ | (886,670) |
| Participant costs | $ | 1,678,046 | $ | - | $ | 1,678,046 |
| Participant Test ratio | | 2.71 | NA | | | 2.98 |

| Non-Participant Test | | Regular Income portfolio without NEEA | | Limited Income portfolio | | Overall portfolio without NEEA |
|---|---|---|---|---|---|---|
| Avoided cost savings | $ | 3,444,273 | $ | 394,347 | $ | 3,838,620 |
| Non-Part benefits | $ | 3,444,273 | $ | 394,347 | $ | 3,838,620 |
| Revenue loss | $ | 6,274,491 | $ | 619,887 | $ | 6,894,378 |
| Implementation | $ | 905,457 | $ | 29,569 | $ | 935,026 |
| Customer incentives | $ | 595,293 | $ | 291,377 | $ | 886,670 |
| Non-Part costs | $ | 7,775,240 | $ | 940,833 | $ | 8,716,073 |
| Non-Part. ratio | | 0.44 | | 0.42 | | 0.44 |

| Descriptive Statistics | | Regular Income portfolio without NEEA | | Limited Income portfolio | | Overall portfolio without NEEA |
|---|---|---|---|---|---|---|
| Annual kWhs | | 13,049,400 | | 1,152,364 | | 14,201,764 |
| Cust cost/kWh | $ | 0.174 | $ | 0.253 | $ | 0.181 |
| Impl cost/kWh | $ | 0.069 | $ | 0.026 | $ | 0.066 |
| El AC $/kWh | $ | 0.330 | $ | 0.397 | $ | 0.335 |
| Inc cost/kWh | $ | 0.046 | $ | 0.253 | $ | 0.062 |

REFERENCE: Comparable to *Table 13* of March 2000 Report.

**Table B10** — **Calculation of Energy Efficiency Tariff Rider Balance and Interest**

| Month | Washington DSM Expenditures | Washington DSM Revenues | Washington Beginning DSM balance | Washington Ending DSM balance | Washington Interest * | Washington Ending bal. with Interest | Idaho DSM Expenditures | Idaho DSM Revenues | Idaho Beginning DSM balance | Idaho Ending DSM balance | Idaho Interest * | Idaho Ending bal. with Interest |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| January 1999 | $ 171,037 | $ 371,658 | $ 2,627,965 | $ 2,828,586 | $ 10,950 | $ 2,839,535 | $ 70,147 | $ 161,905 | $ 1,053,579 | $ 1,145,337 | $ 2,385 | $ 1,147,722 |
| February | $ 188,863 | $ 321,493 | $ 2,839,535 | $ 2,972,165 | $ 21,756 | $ 2,993,921 | $ 100,620 | $ 157,171 | $ 1,147,722 | $ 1,204,273 | $ 8,767 | $ 1,213,040 |
| March | $ 416,803 | $ 292,771 | $ 2,993,921 | $ 2,869,889 | $ 23,172 | $ 2,893,061 | $ 57,166 | $ 143,563 | $ 1,213,040 | $ 1,299,438 | $ 9,378 | $ 1,308,815 |
| April | $ 781,855 | $ 266,606 | $ 2,893,061 | $ 2,377,811 | $ 23,379 | $ 2,401,191 | $ 268,935 | $ 132,749 | $ 1,308,815 | $ 1,172,629 | $ 10,017 | $ 1,182,647 |
| May | $ 333,268 | $ 247,454 | $ 2,401,191 | $ 2,315,377 | $ 21,015 | $ 2,336,392 | $ 131,689 | $ 121,686 | $ 1,182,647 | $ 1,172,644 | $ 9,894 | $ 1,182,538 |
| June | $ 283,079 | $ 266,981 | $ 2,336,392 | $ 2,320,294 | $ 18,805 | $ 2,339,099 | $ 87,749 | $ 121,986 | $ 1,182,538 | $ 1,216,775 | $ 9,391 | $ 1,226,165 |
| July | $ 315,854 | $ 237,115 | $ 2,339,099 | $ 2,260,360 | $ 18,567 | $ 2,278,927 | $ 82,662 | $ 121,018 | $ 1,226,165 | $ 1,264,521 | $ 9,566 | $ 1,274,087 |
| August | $ 470,627 | $ 272,035 | $ 2,278,927 | $ 2,080,335 | $ 18,338 | $ 2,098,673 | $ 146,099 | $ 82,983 | $ 1,274,087 | $ 1,210,971 | $ 9,931 | $ 1,220,902 |
| September | $ 220,534 | $ 302,045 | $ 2,098,673 | $ 2,180,184 | $ 17,381 | $ 2,197,565 | $ 85,885 | $ 86,004 | $ 1,220,902 | $ 1,221,021 | $ 9,908 | $ 1,230,929 |
| October | $ 333,763 | $ 260,080 | $ 2,197,565 | $ 2,123,882 | $ 17,060 | $ 2,140,942 | $ 304,545 | $ 81,571 | $ 1,230,929 | $ 1,007,955 | $ 9,736 | $ 1,017,691 |
| November | $ 174,943 | $ 263,916 | $ 2,140,942 | $ 2,229,915 | $ 17,230 | $ 2,247,145 | $ 167,877 | $ 85,391 | $ 1,017,691 | $ 935,206 | $ 8,927 | $ 944,132 |
| December | $ 588,013 | $ 317,111 | $ 2,247,145 | $ 1,976,243 | $ 17,427 | $ 1,993,670 | $ 232,356 | $ 102,257 | $ 944,132 | $ 814,034 | $ 7,786 | $ 821,820 |
| January 2000 | $ 211,344 | $ 350,395 | $ 1,993,670 | $ 2,132,721 | $ 16,839 | $ 2,149,560 | $ 143,926 | $ 93,727 | $ 821,820 | $ 771,621 | $ 7,010 | $ 778,631 |
| 1999 totals | $ 4,278,640 | $ 3,419,265 | | | $ 225,080 | | $ 1,735,728 | $ 1,398,284 | | | $ 105,685 | |
| 2000 totals | $ 211,344 | $ 350,395 | | | $ 16,839 | | $ 143,926 | $ 93,727 | | | $ 7,010 | |

| Month | Combined DSM Expenditures | Combined DSM Revenues | Combined Beginning DSM balance | Combined Ending DSM balance | Combined Interest * | Combined Ending bal. with Interest |
|---|---|---|---|---|---|---|
| January 1999 | $ 241,185 | $ 533,563 | $ 3,681,544 | $ 3,973,922 | $ 13,335 | $ 3,987,257 |
| February | $ 289,483 | $ 478,664 | $ 3,987,257 | $ 4,176,438 | $ 30,523 | $ 4,206,961 |
| March | $ 473,969 | $ 436,334 | $ 4,206,961 | $ 4,169,326 | $ 32,549 | $ 4,201,876 |
| April | $ 1,050,790 | $ 399,355 | $ 4,201,876 | $ 3,550,440 | $ 33,397 | $ 3,583,837 |
| May | $ 464,956 | $ 369,140 | $ 3,583,837 | $ 3,488,021 | $ 30,909 | $ 3,518,930 |
| June | $ 370,828 | $ 388,967 | $ 3,518,930 | $ 3,537,069 | $ 28,196 | $ 3,565,265 |
| July | $ 398,516 | $ 358,133 | $ 3,565,265 | $ 3,524,881 | $ 28,133 | $ 3,553,014 |
| August | $ 616,726 | $ 355,018 | $ 3,553,014 | $ 3,291,306 | $ 28,269 | $ 3,319,575 |
| September | $ 306,419 | $ 388,049 | $ 3,319,575 | $ 3,401,205 | $ 27,289 | $ 3,428,494 |
| October | $ 638,308 | $ 341,651 | $ 3,428,494 | $ 3,131,837 | $ 26,796 | $ 3,158,634 |
| November | $ 342,820 | $ 349,307 | $ 3,158,634 | $ 3,165,121 | $ 26,157 | $ 3,191,277 |
| December | $ 820,369 | $ 419,368 | $ 3,191,277 | $ 2,790,277 | $ 25,213 | $ 2,815,490 |
| January 2000 | $ 355,270 | $ 444,122 | $ 2,815,490 | $ 2,904,342 | $ 23,849 | $ 2,928,191 |
| 1999 totals | $ 6,014,368 | $ 4,817,549 | | | $ 330,765 | |
| 2000 totals | $ 355,270 | $ 444,122 | | | $ 23,849 | |

**REFERENCE:** Comparable to *Table 14* of March 2000 Report.

# Appendix D

# Exhibit D – Annual Load and Resource Forecast

| | | AVISTA CORP. | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Requirements and Resources | | | | | | | | | | | | | | | | | | | | | |
| figures in MW | | 2000 | | 2001 | | 2002 | | 2003 | | 2004 | | 2005 | | 2006 | | 2007 | | 2008 | | 2009 | |
| Line No. | REQUIREMENTS | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg | Pk | Avg |
| 1 | System Load | 1557 | 1008 | 1594 | 1013 | 1557 | 971 | 1572 | 982 | 1608 | 1007 | 1649 | 1033 | 1692 | 1059 | 1743 | 1091 | 1796 | 1124 | 1851 | 1159 |
| 2 | PacifiCorp Exchange | 0 | 3 | 0 | 3 | 0 | 3 | 0 | 3 | 0 | 3 | 0 | 3 | 0 | 3 | 0 | 3 | 0 | 3 | 0 | 3 |
| 3 | Puget #2 | 100 | 75 | 67 | 50 | 33 | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | PacifiCorp 1994 | 0 | 9 | 0 | 9 | 0 | 9 | 0 | 9 | 0 | 9 | 0 | 9 | 0 | 9 | 0 | 9 | 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 | Snohomish 10 yr | 100 | 88 | 100 | 88 | 100 | 88 | 100 | 88 | 100 | 88 | 100 | 88 | 100 | 88 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Cogentrix 57 mo | 100 | 100 | 100 | 75 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Nichols Pumping | 0 | 7 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | West Kootenay | 125 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Eugene Water & Electric | 10 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | PGE Sale | 25 | 25 | 25 | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | Pend Oreille | 6 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Montana Sale | 100 | 100 | 100 | 58 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Duke Sale | 100 | 100 | 100 | 58 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Clark2 PUD | 250 | 137 | 250 | 85 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | City of Cheney | 2 | 2 | 2 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | Reserves | 246 | 0 | 249 | 0 | 246 | 0 | 247 | 0 | 251 | 0 | 255 | 0 | 259 | 0 | 264 | 0 | 270 | 0 | 275 | 0 |
| 18 | TOTAL REQUIREMENTS | 2871 | 1662 | 2737 | 1470 | 2086 | 1096 | 2069 | 1082 | 2109 | 1107 | 2154 | 1133 | 2201 | 1159 | 2157 | 1103 | 2216 | 1127 | 2276 | 1162 |
| | | | | | | | | | | | | | | | | | | | | | |
| | RESOURCES | | | | | | | | | | | | | | | | | | | | |
| 19 | System Hydro | 936 | 313 | 936 | 313 | 936 | 313 | 936 | 313 | 936 | 313 | 936 | 313 | 936 | 313 | 936 | 313 | 936 | 313 | 936 | 313 |
| 20 | Contract Hydro | 195 | 76 | 195 | 76 | 195 | 76 | 195 | 76 | 195 | 76 | 195 | 71 | 140 | 50 | 140 | 50 | 140 | 50 | 140 | 44 |
| 21 | Can Ent Return | -10 | -5 | -10 | -5 | -10 | -5 | -10 | -5 | -15 | -5 | -15 | -4 | -11 | -4 | -10 | -4 | -10 | -4 | -10 | -3 |
| 22 | Small Power | 12 | 11 | 12 | 11 | 12 | 11 | 12 | 11 | 12 | 11 | 12 | 11 | 12 | 11 | 12 | 11 | 12 | 11 | 12 | 11 |
| 23 | Cogeneration | 59 | 55 | 59 | 55 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | Northeast CTs | 69 | 5 | 69 | 5 | 69 | 5 | 69 | 5 | 69 | 5 | 69 | 5 | 69 | 5 | 69 | 5 | 69 | 5 | 69 | 5 |
| 25 | Rathdrum CTs | 176 | 62 | 176 | 62 | 176 | 62 | 176 | 62 | 176 | 62 | 176 | 62 | 176 | 62 | 176 | 62 | 176 | 62 | 176 | 62 |
| 26 | PacifiCorp Exchange | 50 | 3 | 50 | 3 | 50 | 3 | 50 | 3 | 50 | 3 | 50 | 3 | 50 | 3 | 50 | 3 | 50 | 3 | 50 | 3 |
| 27 | BPA/Avista Exchange | 32 | 12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 28 | Entitlement & Supplemental | 5 | 0 | 4 | 0 | 4 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 29 | BPA Res. Exchange | 0 | 0 | 0 | 12 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 72 | 149 | 149 | 149 | 149 | 149 | 149 |
| 30 | BPA-WNP #3 | 82 | 41 | 82 | 41 | 82 | 41 | 82 | 41 | 82 | 41 | 82 | 41 | 82 | 41 | 82 | 41 | 82 | 41 | 82 | 41 |
| 31 | CSPE | 10 | 5 | 9 | 5 | 9 | 5 | 8 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 32 | TransAlta-Centralia | 200 | 138 | 200 | 143 | 200 | 143 | 200 | 143 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | Thermal- Kettle Falls | 48 | 45 | 48 | 45 | 48 | 45 | 48 | 45 | 48 | 45 | 48 | 45 | 48 | 45 | 48 | 45 | 48 | 45 | 48 | 45 |
| 34 | Colstrip | 222 | 191 | 222 | 191 | 222 | 191 | 222 | 191 | 222 | 191 | 222 | 191 | 222 | 191 | 222 | 191 | 222 | 191 | 222 | 191 |
| 35 | SEMPRA | 0 | 19 | 0 | 19 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 36 | BPA 5 yr. Purchase | 115 | 115 | 115 | 86 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 37 | Idaho Purchase | 100 | 100 | 100 | 58 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 38 | Duke Purchase | 100 | 100 | 100 | 58 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 39 | MIECO | 25 | 25 | 25 | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 40 | Cinergy Services, Inc. | 0 | 14 | 0 | 14 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 41 | Energy Services, Inc. | 0 | 50 | 0 | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 42 | Enron | 50 | 50 | 50 | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 43 | TOTAL RESOURCES | 2476 | 1425 | 2442 | 1267 | 2040 | 944 | 2039 | 933 | 1822 | 789 | 1822 | 785 | 1771 | 789 | 1874 | 866 | 1874 | 866 | 1874 | 861 |
| | | | | | | | | | | | | | | | | | | | | | |
| 44 | SURPLUS (DEFICIT) | -395 | -237 | -295 | -203 | -46 | -152 | -30 | -149 | -287 | -318 | -332 | -348 | -430 | -370 | -283 | -237 | -342 | -261 | -402 | -301 |

# Appendix E

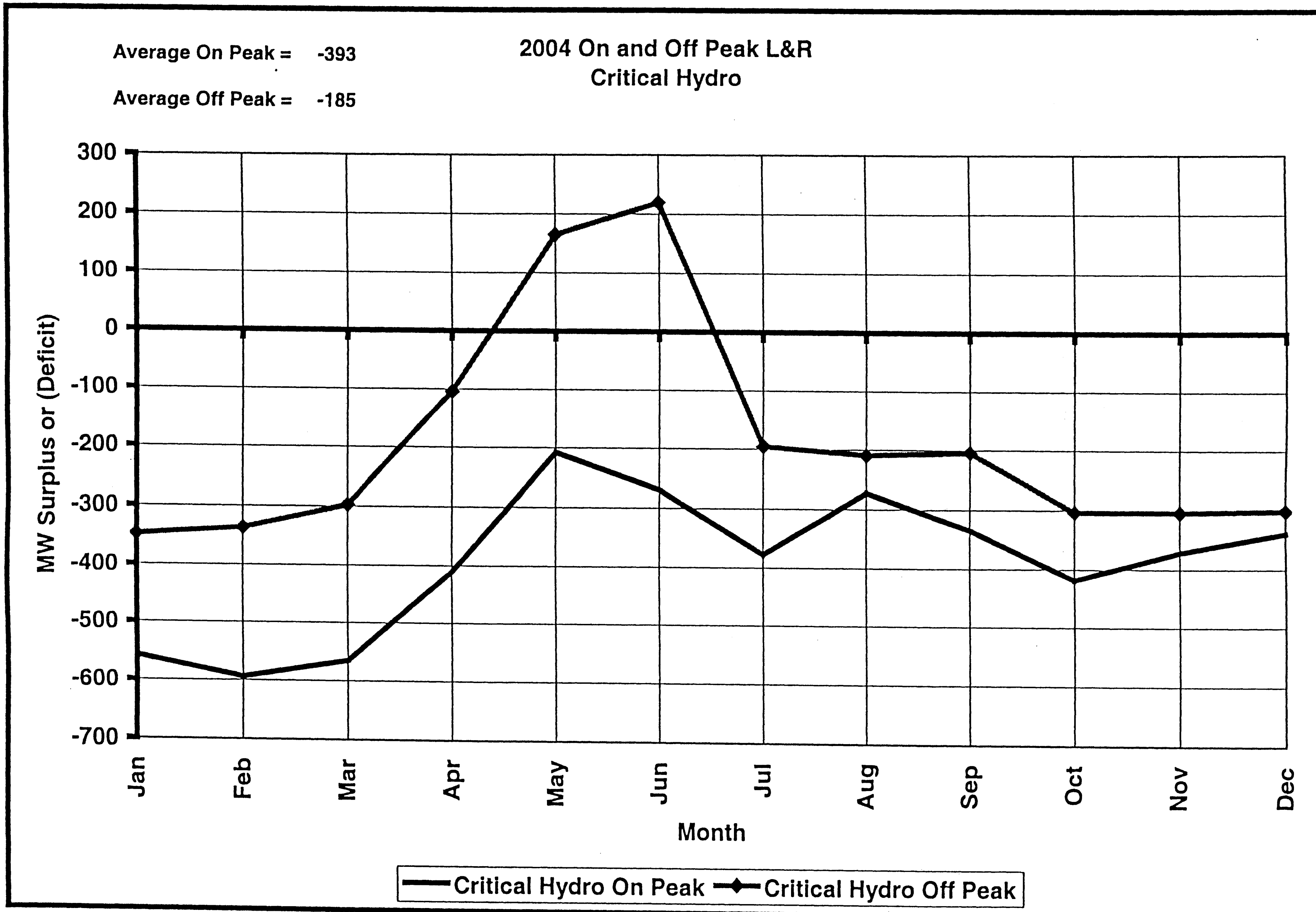
# Avista Utilities

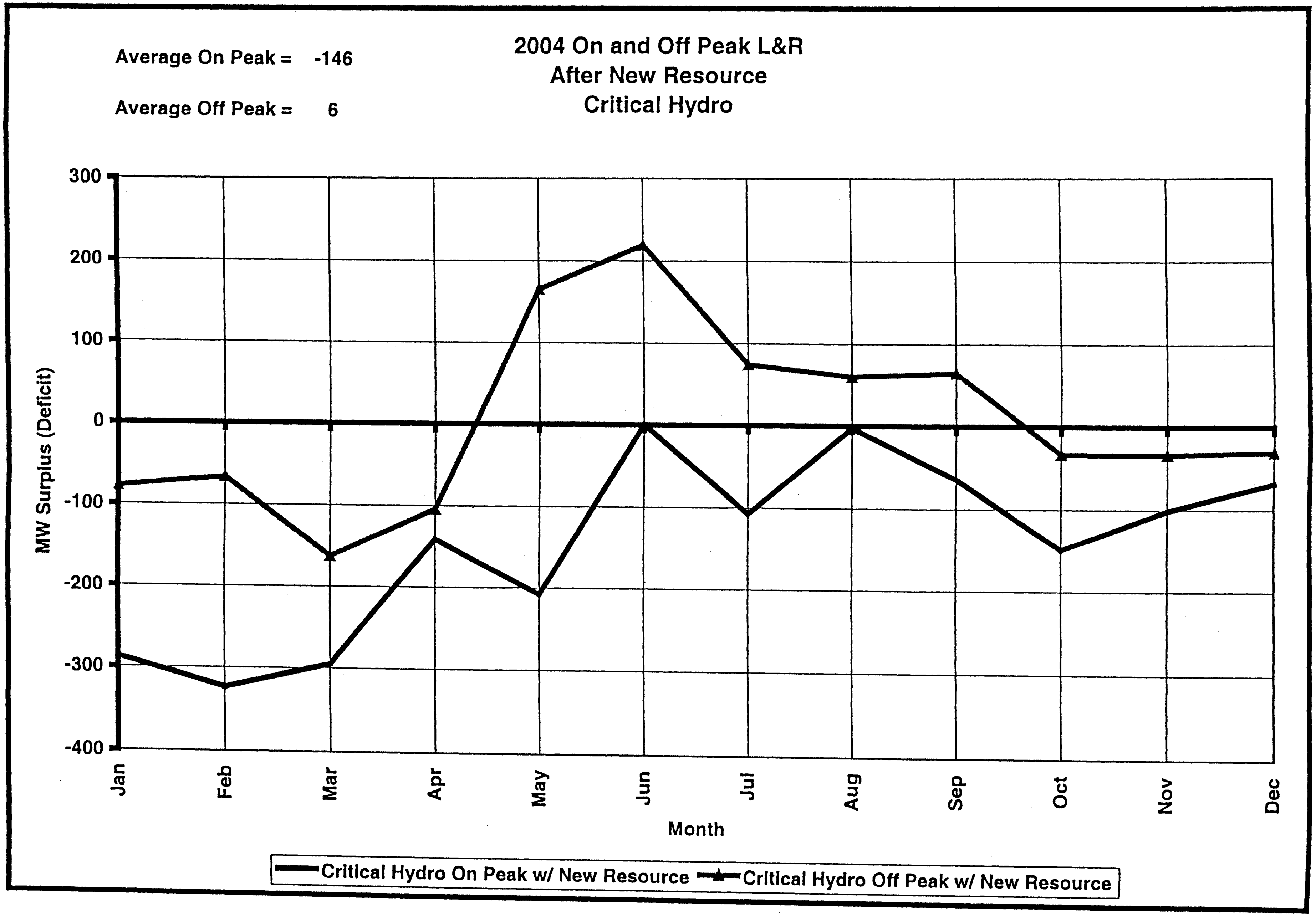
## System Physical Surplus/(Deficiency)

## 2004

## Critical Hydro Conditions

| Month & Hours | Net System Load | PacifiCorp Exchange | Spokane Upriver | Contract Resources: Small Power | Contract Resources: BPA Subscrip | Contract Resources: BPA WNP #3 | Contract Requirements: Can Ent Rtn | Contract Requirements: PGE #1 | Contract Requirements: SnoPud | Cogen. | Colstrip | Kettle Falls | NE | Rathdrum | Mid C Hydro | Clark Fork & Spokane Hydro | Total Resource | Total Obligation | Physical Surplus/ (Deficiency) | New Flexible Resource Acquisition | Physical Surplus/ (Deficiency) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2004 | | | | | | | | | | | | | | | | | | | | | |
| Jan HL | 1314 | -18.8 | -11 | -4 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -173 | -94 | -242 | -918 | 1475 | -557 | -270 | -287 |
| Jan LL | 1030 | 0.0 | -11 | -4 | -47 | -119 | 5 | -71.5 | 100 | 0 | -200 | -47 | 0 | -85 | -70 | -132 | -715 | 1064 | -348 | -270 | -78 |
| Feb HL | 1222 | -18.8 | -11 | -4 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -63 | -317 | -789 | 1383 | -593 | -270 | -323 |
| Feb LL | 946 | 0.0 | -11 | -4 | -47 | -119 | 5 | -71.5 | 100 | 0 | -200 | -47 | 0 | 0 | -46 | -169 | -643 | 979 | -337 | -270 | -67 |
| Mar HL | 1113 | 0.0 | -12 | -5 | -47 | -41 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -59 | -299 | -709 | 1274 | -565 | -270 | -295 |
| Mar LL | 835 | 0.0 | -12 | -5 | -47 | -61 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -43 | -156 | -571 | 868 | -298 | -135 | -163 |
| Apr HL | 1049 | 0.0 | -13 | -5 | -47 | -41 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -57 | -390 | -799 | 1211 | -411 | -270 | -141 |
| Apr LL | 791 | 0.0 | -13 | -5 | -47 | -61 | 5 | -71.50 | 0 | 0 | -200 | -47 | 0 | 0 | -43 | -204 | -620 | 724 | -104 | 0 | -104 |
| May HL | 1046 | 0.0 | -11 | -5 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -96 | -594 | -1000 | 1208 | -208 | 0 | -208 |
| May LL | 788 | 0.0 | -11 | -5 | -47 | 0 | 5 | -71.50 | 0 | 0 | -200 | -47 | 0 | 0 | -77 | -501 | -887 | 722 | 165 | 0 | 165 |
| Jun HL | 1071 | 0.0 | -10 | -5 | -47 | 0 | 5 | 56.25 | 100 | 0 | -96 | 0 | 0 | 0 | -104 | -700 | -962 | 1232 | -270 | -270 | 0 |
| Jun LL | 774 | 0.0 | -10 | -5 | -47 | 0 | 5 | -71.50 | 0 | 0 | -96 | -47 | 0 | 0 | -89 | -632 | -926 | 707 | 219 | 0 | 219 |
| Jul HL | 1050 | 0.0 | | -4 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -130 | -70 | -336 | -834 | 1211 | -377 | -270 | -107 |
| Jul LL | 765 | 0.0 | | -4 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -61 | -245 | -603 | 799 | -196 | -270 | 74 |
| Aug HL | 1060 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -139 | -88 | -390 | -948 | 1221 | -273 | -270 | -3 |
| Aug LL | 768 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -70 | -67 | -158 | -592 | 802 | -210 | -270 | 60 |
| Sep HL | 964 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -143 | -84 | -232 | -790 | 1125 | -335 | -270 | -65 |
| Sep LL | 715 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -72 | -63 | -112 | -543 | 748 | -205 | -270 | 65 |
| Oct HL | 1079 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -161 | -88 | -242 | -822 | 1240 | -418 | -270 | -148 |
| Oct LL | 816 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -70 | -69 | -111 | -546 | 850 | -304 | -270 | -34 |
| Nov HL | 1173 | 0.0 | | -3 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -167 | -91 | -327 | -963 | 1335 | -371 | -270 | -101 |
| Nov LL | 911 | 0.0 | | -3 | -47 | -119 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -74 | -152 | -641 | 945 | -304 | -270 | -34 |
| Dec HL | 1271 | 0.0 | | -3 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -171 | -116 | -429 | -1094 | 1433 | -339 | -270 | -69 |
| Dec LL | 1010 | 0.0 | | -3 | -47 | -119 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -84 | -243 | -742 | 1043 | -301 | -270 | -31 |
| AVE | 1007 | -1.8 | -5.7 | -3.9 | -47.0 | -41.1 | 5.0 | 0.0 | 89.0 | 0.0 | -190.9 | -44.8 | -4.9 | -61.4 | -76.0 | -313.1 | -790.5 | 1092.1 | -301.6 | -222.8 | -78.8 |
| | | | | | | | | | | | | | | | | | Ave HLH | | -393 | -248 | -146 |
| | | | | | | | | | | | | | | | | | Ave LLH | | -185 | -191 | 6 |


Average On Peak = -393
Average Off Peak = -185
2004 On and Off Peak L&R
Critical Hydro
MW Surplus or (Deficit)
300
200
100
0
-100
-200
-300
-400
-500
-600
-700
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Critical Hydro On Peak
Critical Hydro Off Peak

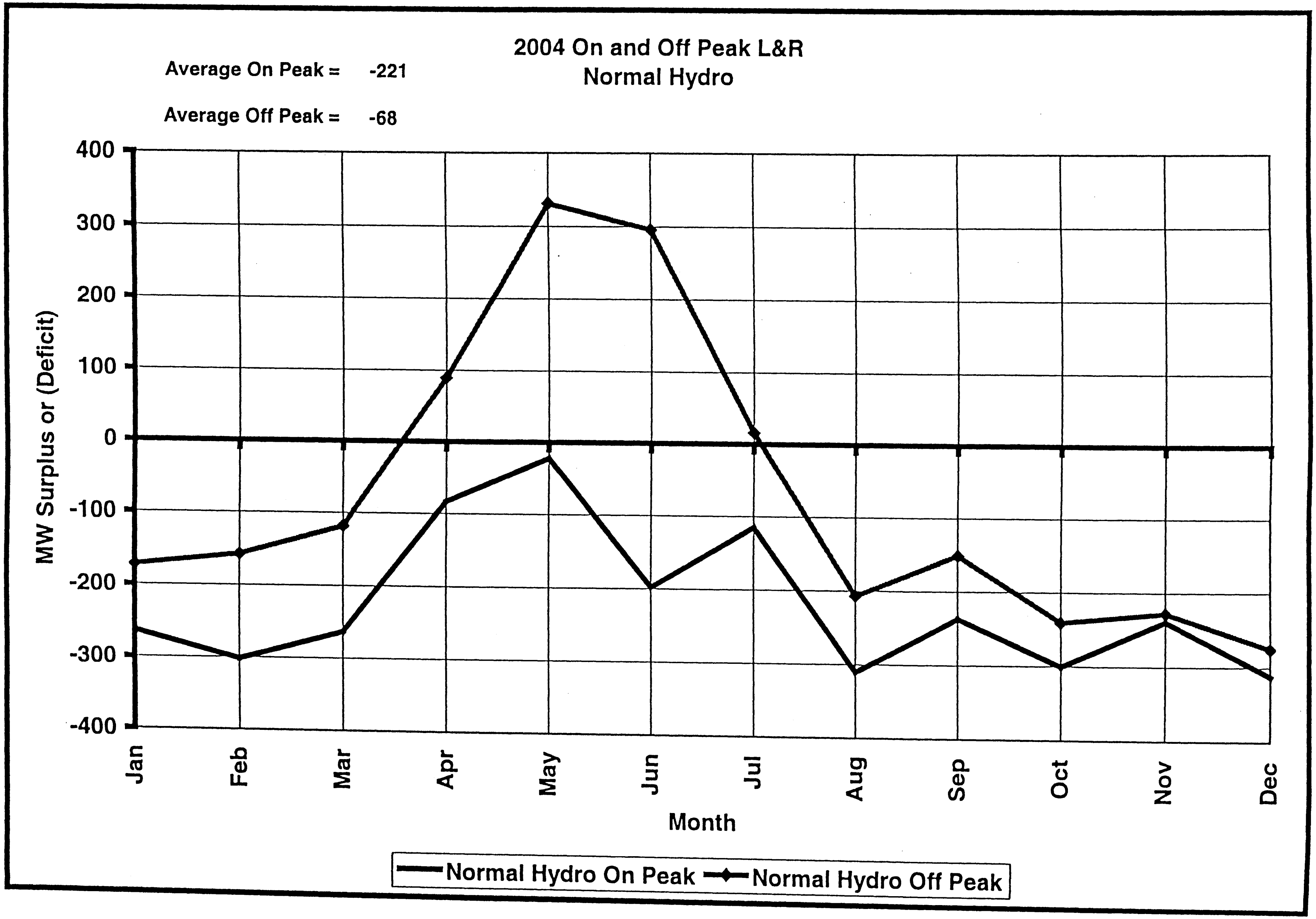

Average On Peak = -146
Average Off Peak = 6
2004 On and Off Peak L&R
After New Resource
Critical Hydro
300
200
100
0
-100
-200
-300
-400
MW Surplus (Deficit)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Critical Hydro On Peak w/ New Resource
Critical Hydro Off Peak w/ New Resource

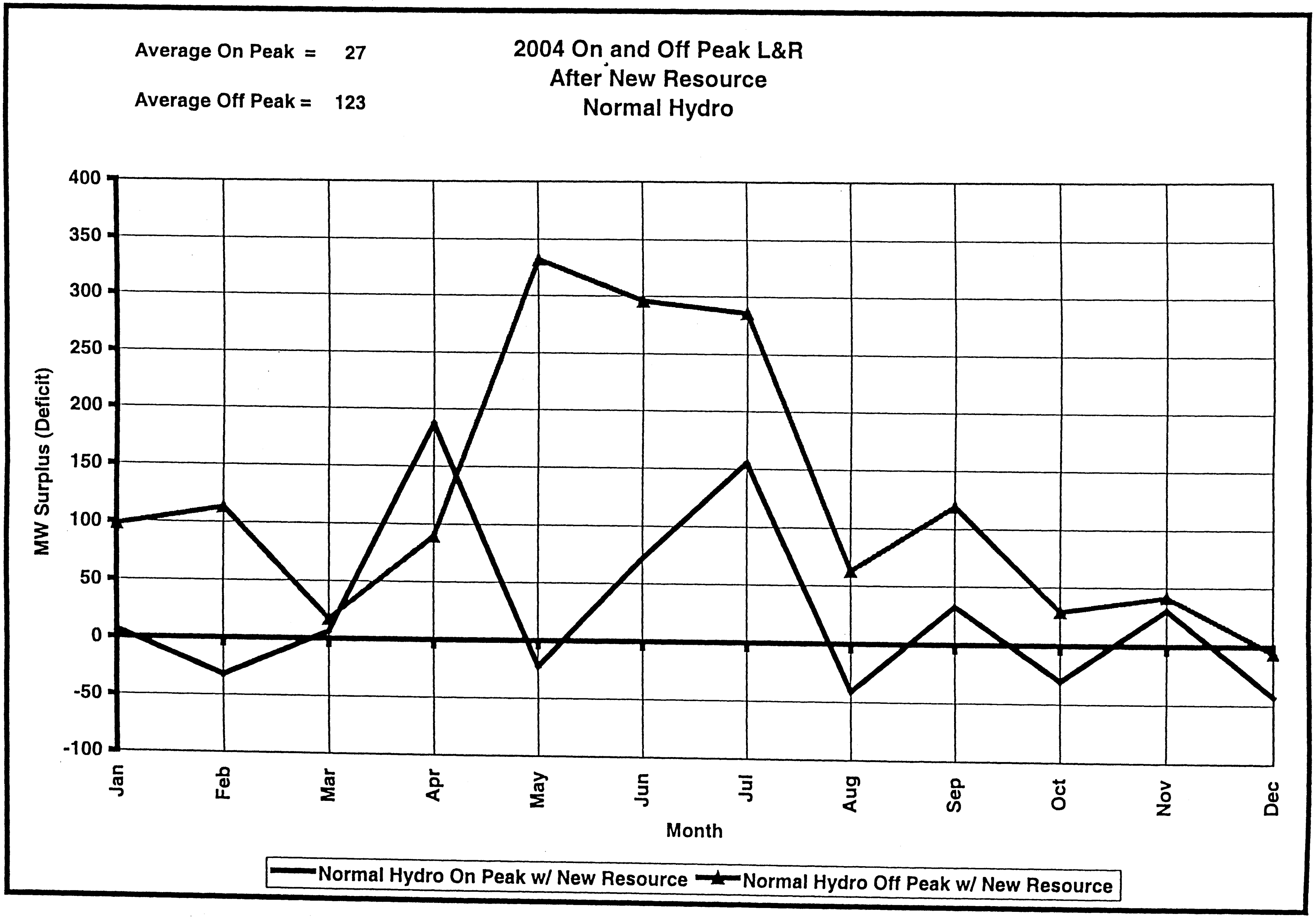
# Avista Utilities

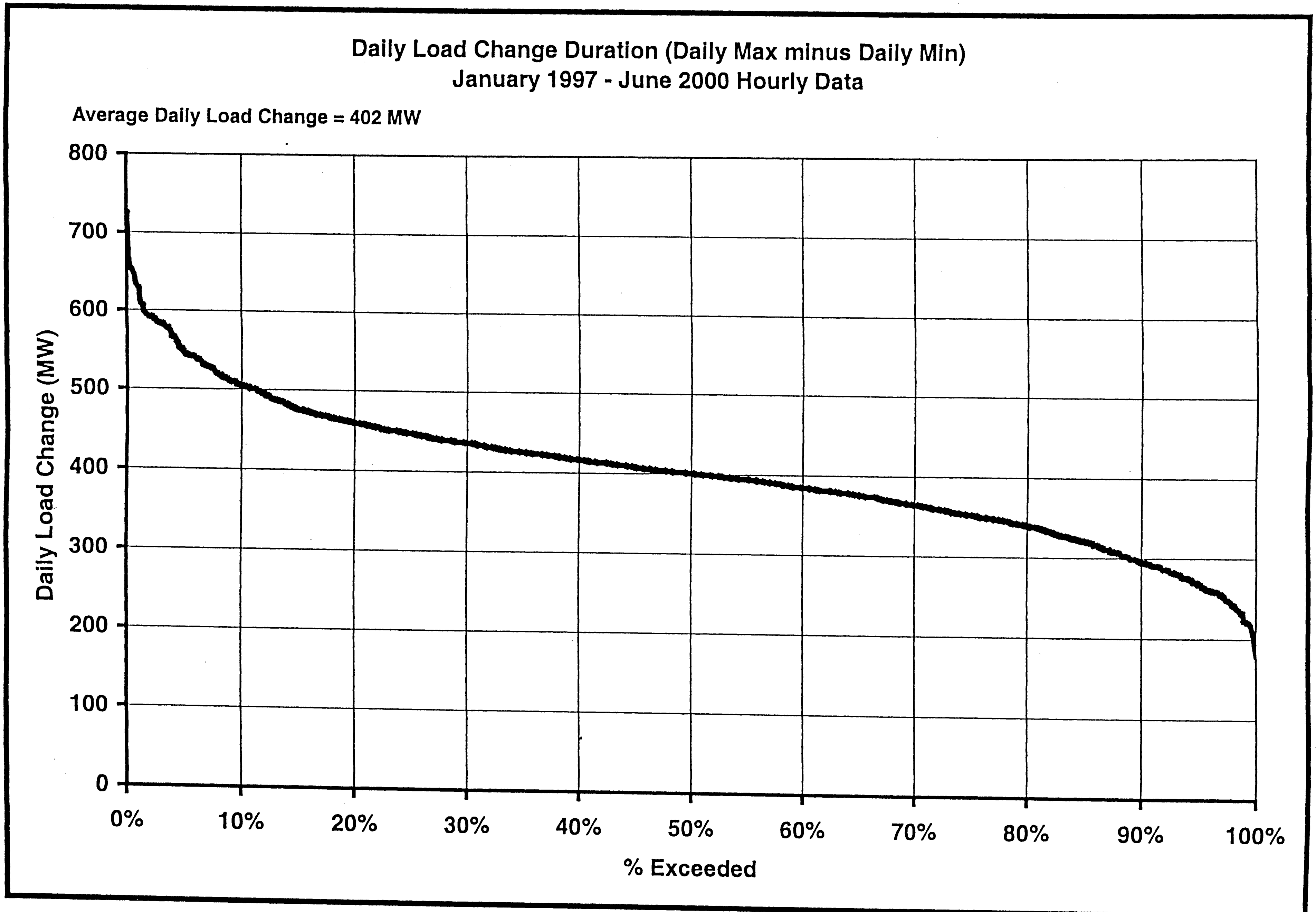
## System Physical Surplus/(Deficiency) — Normal Hydro Conditions

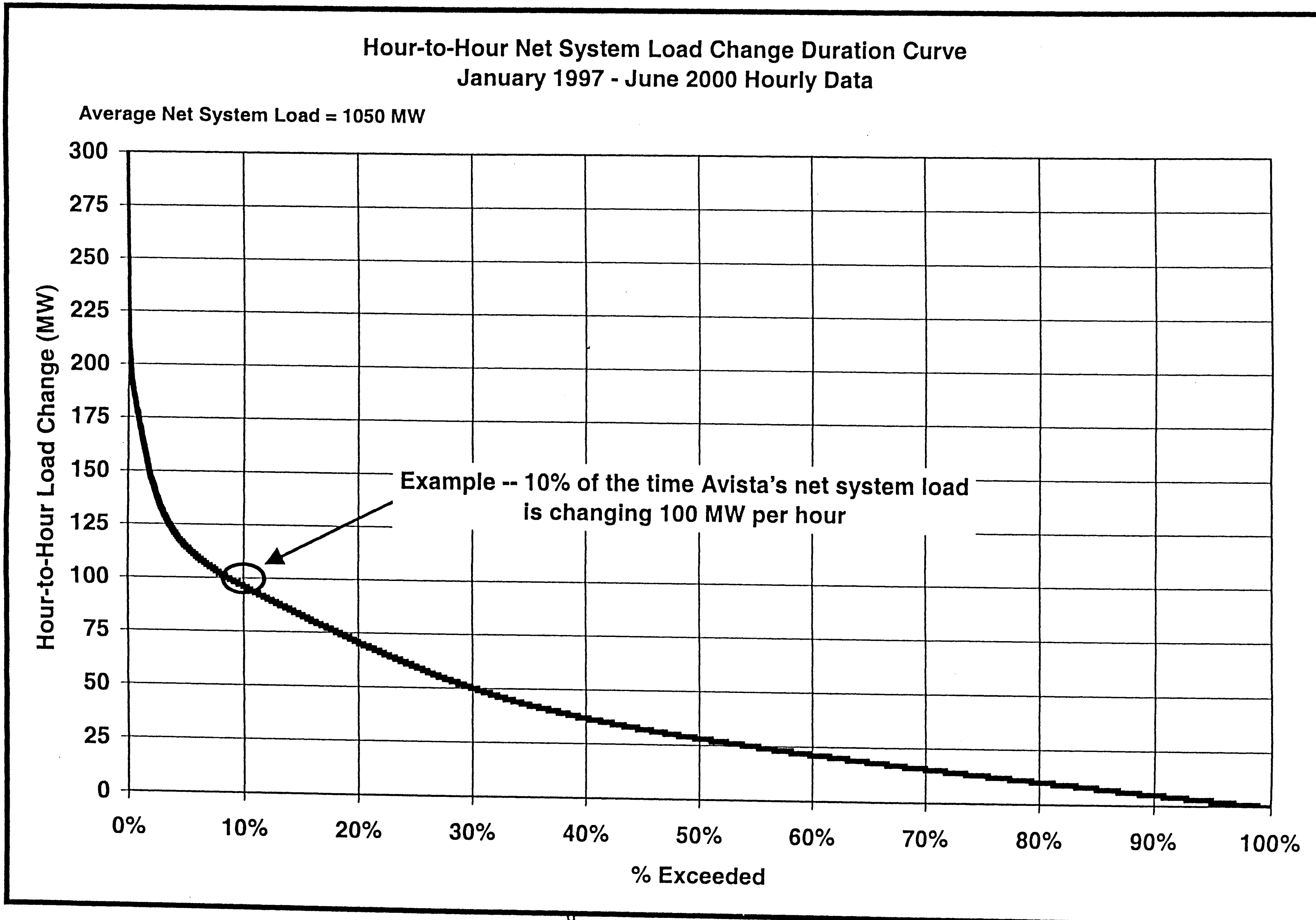
### 2004

| Month & Hours | Net System Load | PacifiCorp Exchange | Contract Resources: Spokane Upriver | Contract Resources: Small Power | Contract Resources: BPA Subscrip | BPA WNP #3 | Contract Requirements: Can Ent Rtn | Contract Requirements: PGE #1 | Contract Requirements: SnoPud | Cogen. | Colstrip | Kettle Falls | NE | Rathdrum | Mid C Hydro | Clark Fork & Spokane Hydro | Total Resource | Total Obligation | Physical Surplus/ (Deficiency) | New Flexible Resource Acquisition | Physical Surplus/ (Deficiency) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2004 | | | | | | | | | | | | | | | | | | | | | |
| Jan HL | 1314 | -18.8 | -11 | -4 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -173 | -125 | -505 | -1212 | 1475 | -263 | -270 | 7 |
| Jan LL | 1030 | 0.0 | -11 | -4 | -47 | -119 | 5 | -71.5 | 100 | 0 | -200 | -47 | 0 | -85 | -103 | -276 | -892 | 1064 | -172 | -270 | 98 |
| Feb HL | 1222 | -18.8 | -11 | -4 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -124 | -548 | -1081 | 1383 | -302 | -270 | -32 |
| Feb LL | 946 | 0.0 | -11 | -4 | -47 | -119 | 5 | -71.5 | 100 | 0 | -200 | -47 | 0 | 0 | -103 | -292 | -823 | 979 | -157 | -270 | 113 |
| Mar HL | 1113 | 0.0 | -12 | -5 | -47 | -41 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -113 | -546 | -1011 | 1274 | -264 | -270 | 6 |
| Mar LL | 835 | 0.0 | -12 | -5 | -47 | -61 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -93 | -286 | -751 | 868 | -118 | -135 | 17 |
| Apr HL | 1049 | 0.0 | -13 | -5 | -47 | -41 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -106 | -669 | -1128 | 1211 | -83 | -270 | 187 |
| Apr LL | 791 | 0.0 | -13 | -5 | -47 | -61 | 5 | -71.50 | 0 | 0 | -200 | -47 | 0 | 0 | -91 | -350 | -814 | 724 | 89 | 0 | 89 |
| May HL | 1046 | 0.0 | -11 | -5 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -94 | -782 | -1186 | 1208 | -22 | 0 | -22 |
| May LL | 788 | 0.0 | -11 | -5 | -47 | 0 | 5 | -71.50 | 0 | 0 | -200 | -47 | 0 | 0 | -85 | -659 | -1054 | 722 | 332 | 0 | 332 |
| Jun HL | 1071 | 0.0 | -10 | -5 | -47 | 0 | 5 | 56.25 | 100 | 0 | -96 | 0 | 0 | 0 | -101 | -775 | -1034 | 1232 | -198 | -270 | 72 |
| Jun LL | 774 | 0.0 | -10 | -5 | -47 | 0 | 5 | -71.50 | 0 | 0 | -96 | -47 | 0 | 0 | -98 | -700 | -1003 | 707 | 296 | 0 | 296 |
| Jul HL | 1050 | 0.0 | | -4 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -130 | -114 | -555 | -1097 | 1211 | -114 | -270 | 156 |
| Jul LL | 765 | 0.0 | | -4 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -112 | -405 | -815 | 799 | 16 | -270 | 286 |
| Aug HL | 1060 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -139 | -103 | -337 | -911 | 1221 | -311 | -270 | -41 |
| Aug LL | 768 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -70 | -91 | -137 | -595 | 802 | -207 | -270 | 63 |
| Sep HL | 964 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -143 | -87 | -326 | -888 | 1125 | -237 | -270 | 33 |
| Sep LL | 715 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -72 | -72 | -157 | -598 | 748 | -151 | -270 | 119 |
| Oct HL | 1079 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -161 | -86 | -362 | -940 | 1240 | -300 | -270 | -30 |
| Oct LL | 816 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -70 | -76 | -166 | -609 | 850 | -241 | -270 | 29 |
| Nov HL | 1173 | 0.0 | | -3 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -167 | -101 | -449 | -1095 | 1335 | -240 | -270 | 30 |
| Nov LL | 911 | 0.0 | | -3 | -47 | -119 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -93 | -208 | -717 | 945 | -228 | -270 | 42 |
| Dec HL | 1271 | 0.0 | | -3 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -171 | -117 | -454 | -1120 | 1433 | -313 | -270 | -43 |
| Dec LL | 1010 | 0.0 | | -3 | -47 | -119 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -95 | -257 | -768 | 1043 | -276 | -270 | -6 |
| AVE | 1007 | -1.8 | -5.7 | -3.9 | -47.0 | -41.1 | 5.0 | 0.0 | 89.0 | 0.0 | -190.9 | -44.8 | -4.9 | -61.4 | -100.1 | -437.1 | -938.6 | 1092.1 | -153.5 | -222.8 | 69.3 |
| | | | | | | | | | | | | | | | | | Ave HLH | | -221 | -248 | 27 |
| | | | | | | | | | | | | | | | | | Ave LLH | | -68 | -191 | 123 |

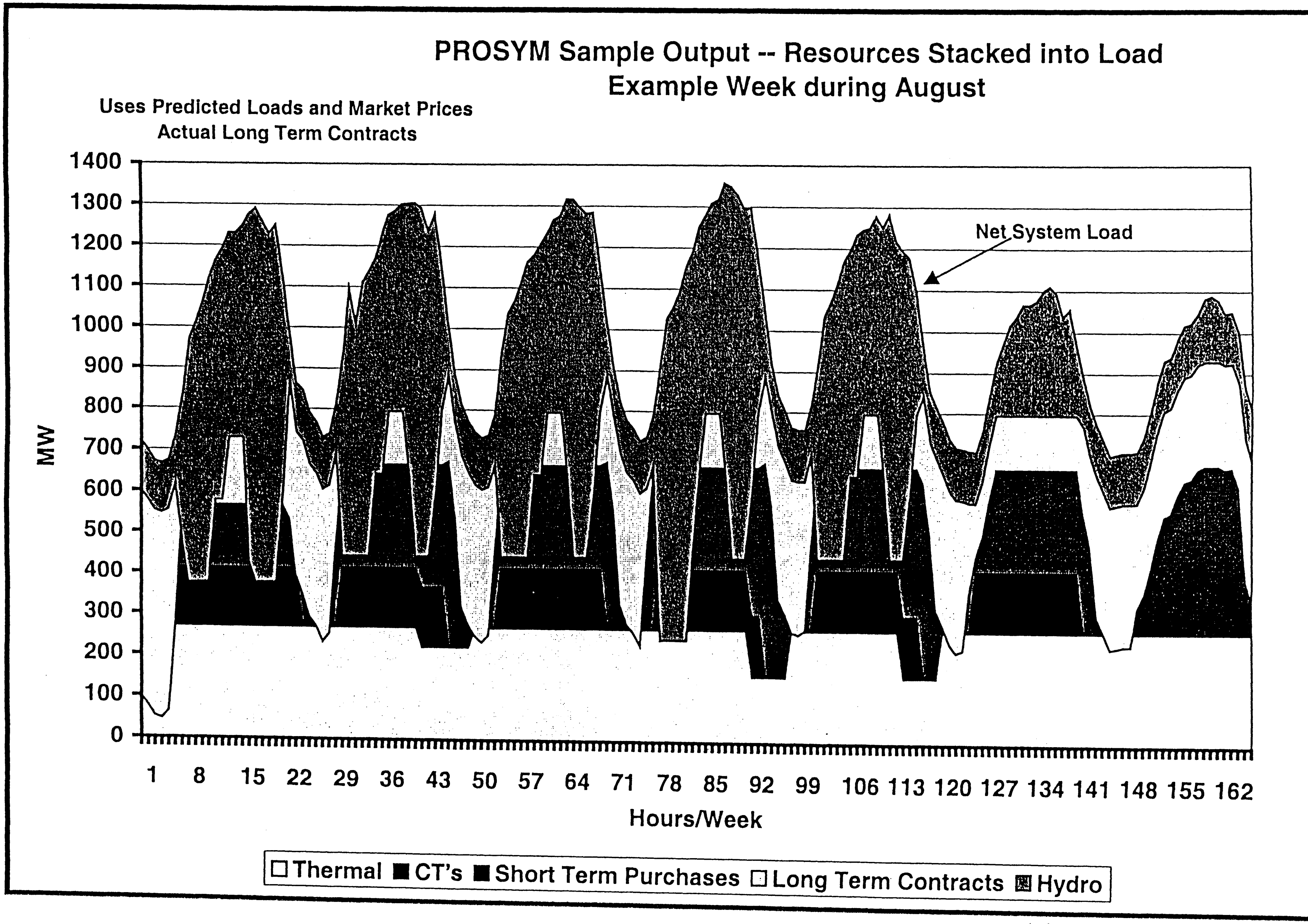

2004 On and Off Peak L&R
Normal Hydro
Average On Peak = -221
Average Off Peak = -68
400
300
200
100
0
-100
-200
-300
-400
MW Surplus or (Deficit)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Normal Hydro On Peak
Normal Hydro Off Peak


Average On Peak = 27
Average Off Peak = 123
2004 On and Off Peak L&R
After New Resource
Normal Hydro
MW Surplus (Deficit)
400
350
300
250
200
150
100
50
0
-50
-100
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Normal Hydro On Peak w/ New Resource
Normal Hydro Off Peak w/ New Resource

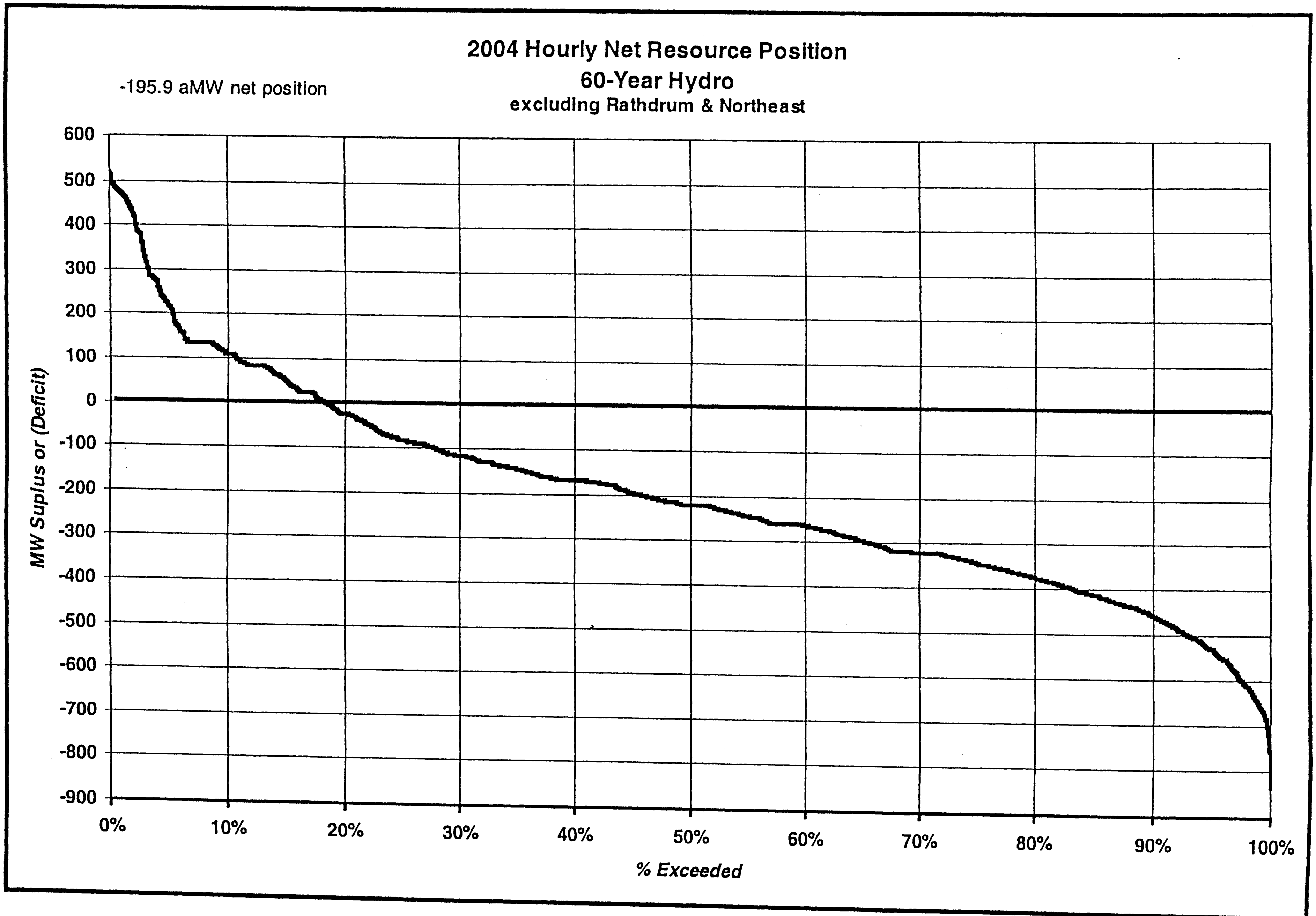

Daily Load Change Duration (Daily Max minus Daily Min)
January 1997 - June 2000 Hourly Data
Average Daily Load Change = 402 MW
Daily Load Change (MW)
800
700
600
500
400
300
200
100
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% Exceeded

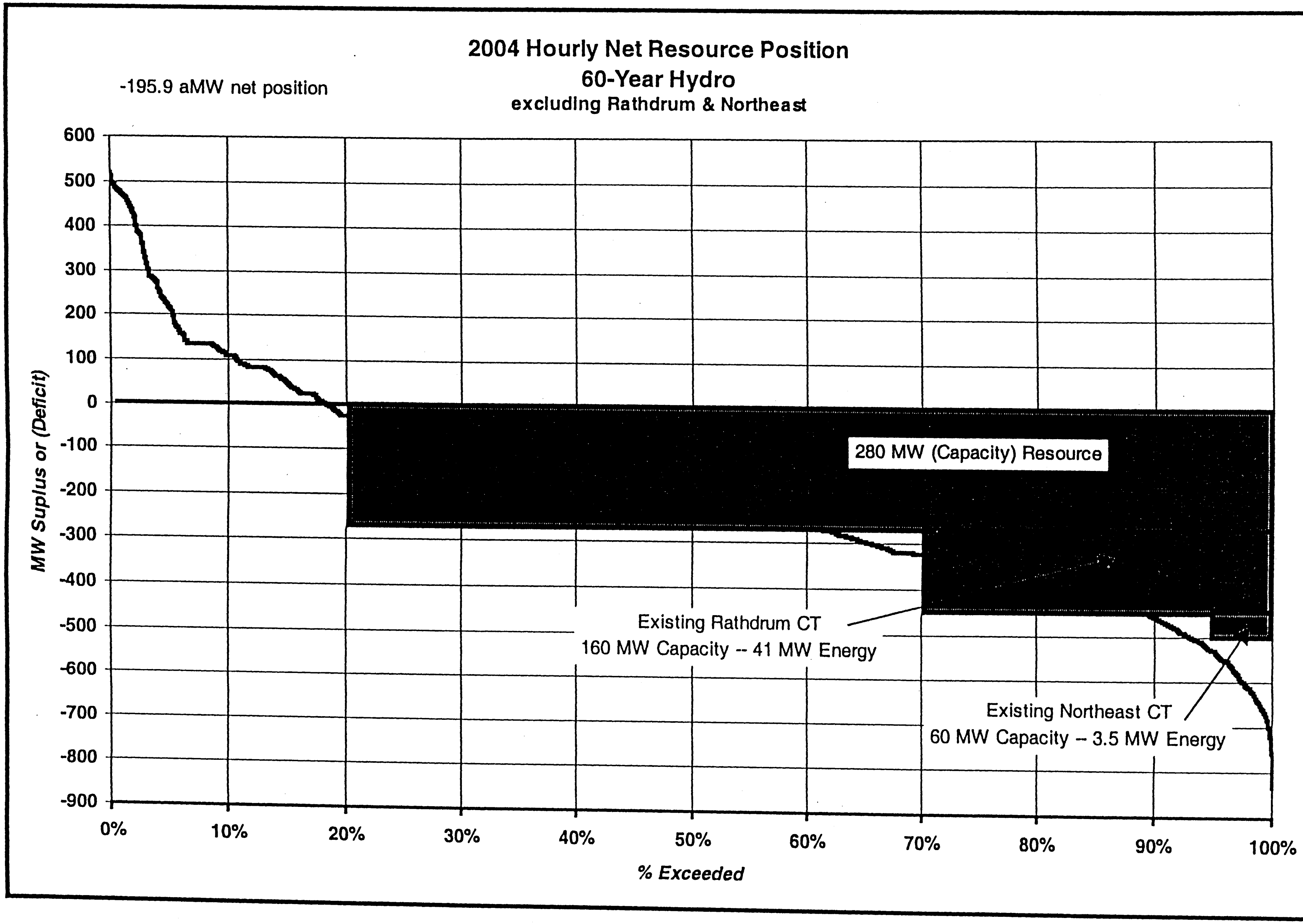


Hour-to-Hour Net System Load Change Duration Curve
January 1997 - June 2000 Hourly Data
Average Net System Load = 1050 MW
Hour-to-Hour Load Change (MW)
300
275
250
225
200
175
150
125
100
75
50
25
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% Exceeded
Example -- 10% of the time Avista's net system load is changing 100 MW per hour



PROSYM Sample Output -- Resources Stacked into Load
Example Week during August
Uses Predicted Loads and Market Prices
Actual Long Term Contracts
MW
1400
1300
1200
1100
1000
900
800
700
600
500
400
300
200
100
0
Net System Load
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hours/Week
Thermal
CT's
Short Term Purchases
Long Term Contracts
Hydro


2004 Hourly Net Resource Position
60-Year Hydro
excluding Rathdrum & Northeast
-195.9 aMW net position
MW Suplus or (Deficit)
600
500
400
300
200
100
0
-100
-200
-300
-400
-500
-600
-700
-800
-900
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% Exceeded



2004 Hourly Net Resource Position
60-Year Hydro
excluding Rathdrum & Northeast
-195.9 aMW net position
600
500
400
300
200
100
0
-100
-200
-300
-400
-500
-600
-700
-800
-900
MW Suplus or (Deficit)
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% Exceeded
280 MW (Capacity) Resource
Existing Rathdrum CT
160 MW Capacity -- 41 MW Energy
Existing Northeast CT
60 MW Capacity -- 3.5 MW Energy

# MODEL CONTRACTS

(not included)

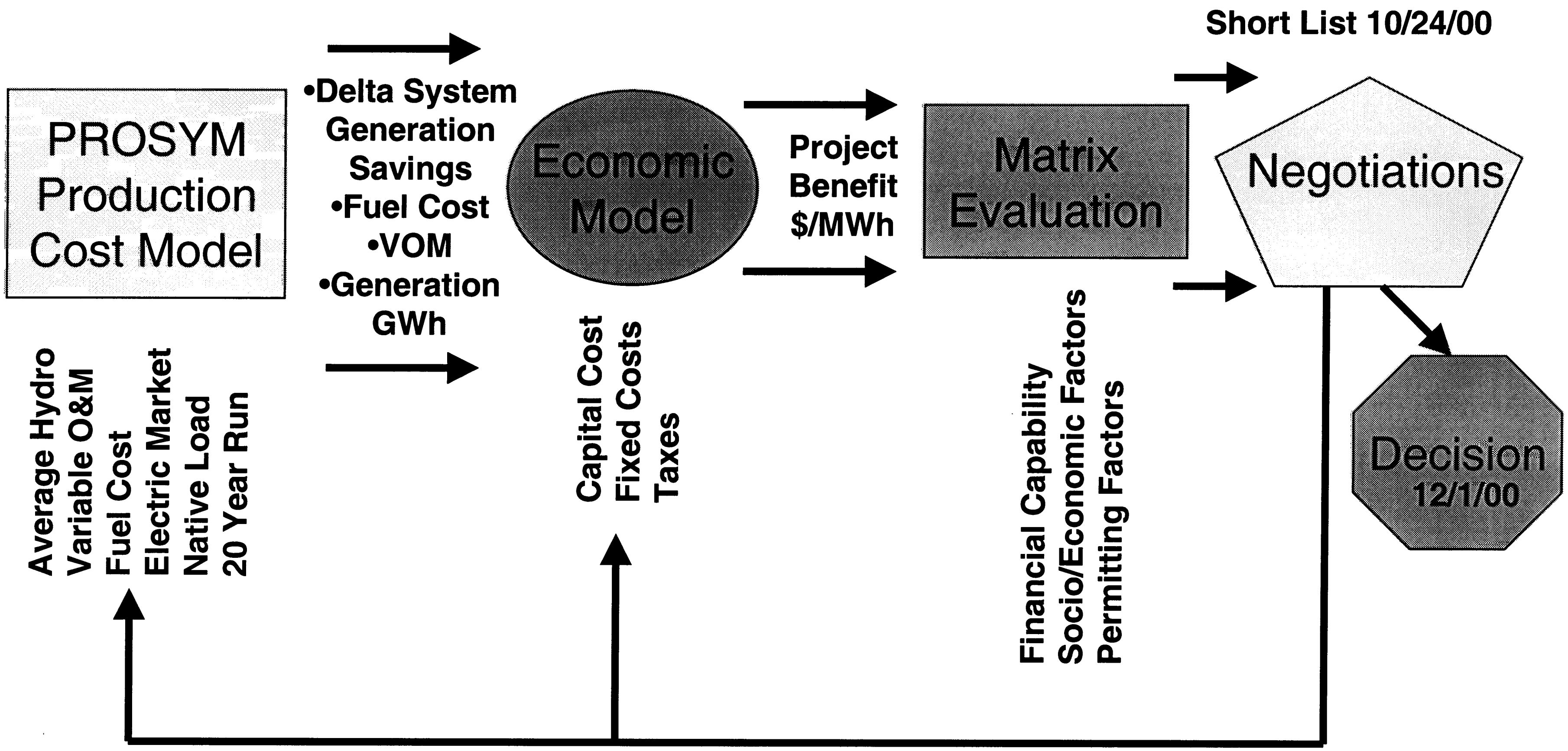
BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-4)

# RFP Evaluation Process



September 15, 2000

**AVISTA EVALUATION GUIDANCE FOR ELECTRIC RFP BID PROPOSALS (Power Supply Resources)**

***August 14, 2000 RFP available to potential bidders***

Avista's 2000 RFP indicated various characteristics or factors against which bid proposals would be evaluated (see 2000 RFP). Many of these evaluation factors can be assigned monetary values that can be used in the evaluation process. Therefore, economics will be the significant component of the company's bid evaluation process.

Described below is an outline of the evaluation process that Avista plans to generally follow in the bid evaluation process. This outline is intended as a guide. Modifications may be made in order to more appropriately compare and evaluate the bid proposals.

***September 18, 2000 Bids due date to Avista and opening of bids***

Initial Review:

A copy of the bid proposals will be distributed to each member of the Screening Work Group. Their task will be to become familiar with the bids and then make sure they meet the minimum resource evaluation performance. In general the Screening Work Group will look at the performance track record of the bidders, environmental requirements, whether the technology is proven, and the financial and performance capability of the bidder.

In addition the bid proposals must include all necessary information for evaluation in order to pass the initial screening criteria. In the initial review of the bid proposals, if deficiencies are not material, Avista may, at its option, grant a limited extension to cure such deficiencies.

***September 22, 2000 Initial review completed by Avista***

Preliminary Short List:

All power supply resource bids that pass the Initial Screening will go through both a production modeling process and an economic modeling and comparative evaluation process. The resource bids will be ranked as to their relative value provided to the company and its customers using a weighted matrix. From this ranking a preliminary short list will be developed. Company projects will follow the same evaluation course as resource bids submitted to the company under the RFP.

1) Production Modeling - PROSYM:

The chronological production modeling system, PROSYM, will be used for the purpose of producing near and long-term forecasts of electric system variable operating and production cost. Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM closely reflect actual operations. In each hour of a study period, PROSYM considers a complex set of operating constraints to simulate the least-cost operation of the utility. This hour-by hour simulation, respecting chronological, operational, and other constraints in the case of cost-based dispatch, is the essence of the model.

As the company contemplates the addition of one or more resources to its portfolio it will be faced with a different resource stack and fuel mix. The new resources will have an impact on the resource dispatch sequence because of the potential fuel supply and marginal costs. Avista uses PROSYM to model its resources, to meet its system requirements, and to assess the dispatch requirements and compatibility of new resources used in conjunction with existing resources, both hydro and thermal.

Some of the information used in the model includes 20 years of projected on and off peak monthly loads and 20-year forecast of electric and gas prices. All resources and contracts are modeled on an hourly basis. Average hydro is a input into the model and then the hydro is optimized according to Avista's native load.

The PROSYM model will be run with and without the bid proposal to determine the change in system variable cost. This delta in operating costs will allow the company to compare the impacts on its system variable operating costs for each of these bid proposals. Specifically, PROSYM results for variable O&M, fuel costs, portfolio operation costs delta, and generation for each new resource will be provided for use in Step 2.

2) Economic Modeling:

The variable cost information from PROSYM, plus other information, such as the proposed resource fixed or capital cost, will be input to the company's economic models. The economic (or revenue requirements) model includes basic financial assumptions from the corporation, including inflation assumptions. Costs for fixed O&M, capital, taxes, insurance, property taxes, wheeling, and gas transport are also included. The output from these economic models will provide the overall cost or benefit of adding a bid resource to the system compared to a base case. The resources will be evaluated over the life of the resource up to 20 years.

The output from these economic models will be economic indicators that can be compared to determine the most cost-effective resource for the company's system. Unit net project benefit per MWh is one such indicator, which will help rank the different resources as to their added value. An estimate of relative gas and electric price scenarios will be developed and applied to models. Model results from these analyses will be considered when evaluating price risk.

3) Weighted Matrix Evaluation:

The Work Group will then take the bid proposals and using the results from Step 2 above, will evaluate them against each other. A comparison will be made of both price and non-price factors to get an overall view of each bid proposal. This will determine which resource bid(s) provides the greatest relative value to the company and its customers in helping Avista meet its power supply needs.

Weighting of Evaluation Factors – The weighting of factors used to rank bid proposals is split between price (65%) and non-price (35%) factors. Each factor used in the selection process will be assigned a weight shown below that represents its contribution toward meeting Avista's least cost planning goals.

The range of the rating values may be from one to ten (with ten being best) if the number of bids submitted to Avista is small. A larger point spread will be used if the number of bids is larger.

The weighting of bid proposals will be in three characteristics as discussed in the body of the 2000 RFP. However, these three characteristics or factors are combined into two categories. The first category will be Financial/Price Factors and the second will be Electric Power and Social/Environmental Factors.

Under the Financial/Price Factors (65%) are the following:

- The economic benefit of the resource to the company and its customers (35%).
- The long-term financial capability and performance capability of the bidder/developer (15%).
- Fuel price risk (15%).

Under the Electric Power and Social/Environmental Factors (35%) are the following:

Fuel Availability Risk (5%)

- Fuel security of supply risk
- Fuel transportation security/expected performance

Electric Factors (20%)

- Ramp rates
- Dispatchability (number of times per month it can be shut down)
- Reactive capability
- Supply source (market, unit, system, etc.)
- System integration (transmission availability, cost, etc.)
- Exposure to transmission contingencies
- Other characteristics

Environmental Factors (10%)

- Permits- demonstration of permit plans, stage of completion and complexity of obstacles and local impact issues.
- Complies or demonstrates an acceptable plan for compliance for all applicable environmental laws and regulations.
- Technology proven to meet environmental laws and regulations.

Each bid proposal will be rated based upon the bid proposal's relative comparison to other bids. Bid proposals will not be rated on a forced ranking basis. The rating of each bid resource will be multiplied by the weight of the factor. A total weighted calculation will be made for each bid proposal under consideration by summing its weighted rating. This total value will be used to rank bids. Within a narrow range, bid proposals may be viewed as essentially equal in value/benefits. The highest ranked bid proposals will move to the next phase of evaluation as a preliminary short list.

***October 6, 2000 Determination of preliminary short list***

Sponsors' Meetings:

All bid sponsors will be notified regarding the preliminary short list. Meetings will be scheduled with those project sponsors that made the preliminary short list. Avista has found that what the bidders perceive and submit is sometimes different than what the company reads and interprets from the formal bid. These differences have to be resolved. If new information is found as part of this discovery process, steps 1 through 3 under the Preliminary Short-List section may be re-evaluated. Bid proposals may change relative ranking position as a result. This will be iterative if new information at any phase of the evaluation is revealed. Once the meetings have been completed, the Work Group will select those resource bid options that are the best out of those submitted under the 2000 RFP. Again, a close ranking may indicate that more than one project should be considered essentially equal.

***October 20, 2000 Complete meetings with project sponsors***

Selection of Short List for Negotiation:

At this point the company enters into the final discovery and evaluation phase. Any additional information will be acquired and the refinement of this information will be used to re-evaluate and re-compare the relative benefits of the bid proposals.

Once the differences are resolved and the final short list is completed, then the negotiation phase begins. If Avista finds that the terms and conditions of the submitted bids are significantly different from what the bidders are discussing in the meetings then the company will re-evaluate the bids by going through the evaluation process again. If the ranking is different then the new ranking will be used in selecting the best of the bids for further consideration. All terms and conditions are open for negotiation. The final selection will be the conclusion of the RFP process. The result is a final list of most beneficial bid proposals.

***October 24, 2000   Selection of short list for negotiation***

<u>Final Negotiation/Selection:</u>

Any bids that have made the short list for negotiation will begin the negotiation phase with the company. All terms and conditions are open for negotiation, including price. A decision to select or not select resources from the RFP will be the conclusion of the RFP process and the final decision will be announced.

***November 3, 2000   Final selection (RFP decision)***

***December 2000   Debriefing***

***January 15, 2001   Final evaluation report submitted to Commissions***

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-C5)

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AVISTA CORP.
2000 Request-for-Proposals
Weighted Matrix Evaluation

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**Second Round Screening**

10-12-2000

| | | | | Financial/Price Factors | | | Electric Power & Social/Environmental Factors | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Weighting Factor | | 35% | 15% | 15% | 5% | 20% | 10% | 100% |
| | | Ranking | 1 - 10 | | | | | | | |
| Review By RW Beck | No. | Bid/Project Sorted by Ranking | Short List | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors | Weighted Total |
| x | 24 | RCT Upgrades | x | 9 | 10 | 5 | 5 | 10 | 4 | 8.05 |
| x | 21 | Williams Bid #1 Flat Purchase | x | 9 | 10 | 10 | 10 | 4 | 5 | 7.95 |
| | 14 | PG&E Bid #1 Flat Purchase | x | 9 | 9 | 10 | 10 | 4 | 5 | 7.8 |
| | 5 | Enron Bid #1 20 Year Flat | x | 6 | 10 | 10 | 10 | 4 | 5 | 6.9 |
| x | 18 | Regional Power Bid | x | 8 | 5 | 10 | 7 | 4 | 7 | 6.9 |
| | 10 | Enron #6 Turnkey | x | 6 | 10 | 5 | 3 | 9 | 4 | 6.7 |
| | 9 | Enron #5 Tolling | | 7 | 10 | 5 | 3 | 7 | 4 | 6.65 |
| | 6 | Enron Bid #2 10 Year Purch | | 5 | 10 | 10 | 10 | 4 | 5 | 6.55 |
| x | 22 | Williams Bid #2 Tolling | | 5 | 10 | 5 | 5 | 7 | 5 | 6.15 |
| x | 11 | Newport NW Tolling | x | 10 | 1 | 5 | 3 | 6 | 3 | 6.05 |
| | 17 | PG&E Bid #4 Tolling, Umatilla | | 5 | 9 | 5 | 10 | 4 | 3 | 5.45 |
| | 19 | Sumas Bid #1 Tolling | | 5 | 5 | 5 | 5 | 7 | 3 | 5.2 |
| | 2 | Continental Energy Tolling | | 5 | 5 | 5 | 3 | 7 | 3 | 5.1 |
| | 12 | NW Geothermal Bid #1 | | 2 | 5 | 10 | 10 | 3 | 10 | 5.05 |
| | 4 | Engage Bid Tolling | | 4 | 5 | 5 | 5 | 7 | 5 | 5.05 |
| x | 8 | Enron Bid #4 Monthly Dispatch | | 2 | 10 | 5 | 10 | 5 | 5 | 4.95 |
| x | 1 | Calpine Bid Tolling | | 1 | NE | NE | NE | NE | NE | 1 |
| | 3 | Empire Lumber Bid | | 1 | NE | NE | NE | NE | NE | 1 |
| | 7 | Enron Bid #3 Quarterly Dispatch | | 1 | NE | NE | NE | NE | NE | 1 |
| x | 13 | Pacific Winds | | 1 | NE | NE | NE | NE | NE | 1 |
| | 15 | PG&E Bid #2 Monthly Purchase | | 1 | NE | NE | NE | NE | NE | 1 |
| | 16 | PG&E Bid #3 Weekly Purchase | | 1 | NE | NE | NE | NE | NE | 1 |
| | 20 | Sumas Bid #2 Gas tied to Wells | | 1 | NE | NE | NE | NE | NE | 1 |
| | 23 | Clearwater-Yanke Energy Bid #1 | | 1 | NE | NE | NE | NE | NE | 1 |

NE = "Not Evaluated"

DISCUSSED WITH IPUC & WUTC COMMISSION STAFF ON 10/20/00.
ADDED ENRON #6 TURNKEY PROJECT & NEWPORT NW TOLLING PROJECT TO SHORT LIST
AT THE REQUEST OF STAFF.

## 2nd Round Screening
## RFP Bid Evaluation Matrix Documentation

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| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 1 | Calpine Bid Tolling | Rating=1<br><br>The nominal levelized cost (NLC) of this bid is worse than ($15.00/MWh) below the base case. As such, it is significantly uneconomic compared to several other bids. This project will not be further evaluated. | NE<br><br>(Not Evaluated) | NE<br><br>(Not Evaluated) | NE<br><br>(Not Evaluated) | NE<br><br>(Not Evaluated) | NE<br><br>(Not Evaluated) |
| 2 | Continental Energy Tolling | Rating=6<br><br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 5th tier of nominal levelized cost: NLC=$(5.00)MWh to ($6.00)/MWh | Rating=5<br><br>Average rating due to lack of information on their new ownership status. | Rating=5<br><br>Price reflect potential volatility of natural gas. | Rating=3<br><br>Construction of 110 mile pipeline required. | Rating=7<br><br>Tolling unit tied to a Butte, Mt CCCT. May allow some dispatchability (unspecified). | Rating=3<br><br>Turbine project would normally get a 5 rating. However, this project rating reduced due to significant permitting hurdles. Need gas line permits. No PSD permit. |
| 3 | Empire Lumber Bid | Rating=1<br><br>The nominal levelized cost (NLC) of this bid is worse than ($15.00/MWh) below the base case. As such, it is significantly uneconomic compared to several other bids. This project will not be further evaluated. | Rating=NE<br><br>(Not Evaluated) | Rating=NE<br><br>(Not Evaluated) | Rating=NE<br><br>(Not Evaluated) | Rating=NE<br><br>(Not Evaluated) | Rating=NE<br><br>(Not Evaluated) |

## 2nd Round Screening
## RFP Bid Evaluation Matrix Documentation

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October 12, 2000

| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 4 | Engage Bid Tolling | Rating=4<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 7th tier of nominal levelized cost: NLC=$(9.00)MWh to ($11.00)/MWh | Rating=5<br>Average rating due to lack of information on their new ownership status. | Rating=5<br>Price reflect potential volatility of natural gas. | Rating=5<br>Transportation probably available at market rates. | Rating=7<br>Tolling unit tied to Fredrickson. Some flexibility but unspecified as to how much. | Rating=5<br>Permitted turbines received a five rating. |
| 5 | Enron Bid #1 20 Year Flat | Rating=6<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 5th tier of nominal levelized cost: NLC=$(4.50)MWh to ($6.50)/MWh | Rating=10<br>Top rating. | Rating=10<br>Fixed price; no fuel risk. | Rating=10<br>No fuel transportation risk. Not tied to a specific plant. | Rating=4<br>Market purchase. No dispatchability. BPA transmission assumed - unconstrained path. | Rating=5<br>Assigned all market power bids a turbine rating of five. If it is a blended product, we are assuming that the resources are equivalent to a turbine. |
| 6 | Enron Bid #2 10 Year Purch | Rating=5<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 6th tier of nominal levelized cost: NLC=$(6.50)MWh to ($9.00)/MWh | Rating=10<br>Top rating | Rating=10<br>Fixed price; no fuel risk. | Rating=10<br>No fuel transportation risk. | Rating=4<br>Market purchase. No dispatchability. BPA transmission assumed - unconstrained path. | Rating=5<br>Assigned all market power bids a turbine rating of five. If it is a blended product, we are assuming that the resources are equivalent to a turbine. |

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## 2nd Round Screening
## RFP Bid Evaluation Matrix Documentation

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| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 7 | Enron Bid #3 Quarterly Dispatch | Rating=1<br>The nominal levelized cost (NLC) of this bid is worse than ($15.00/MWh) below the base case. As such, it is significantly uneconomic compared to several other bids. This project will not be further evaluated. | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] |
| 8 | Enron Bid #4 Monthly Dispatch | Rating=2<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 8th tier of nominal levelized cost: NLC=$(11.00)MWh to ($15.00)/MWh | Rating=10<br>Top rating | Rating=5<br>Tied to natural gas price and a heat rate. | Rating=10<br>No fuel transportation risk. Not tied to a specific plant. | Rating=5<br>Market sale. Monthly dispatchability. BPA transmission assumed - unconstrained path. | Rating=5<br>Assigned all market power bids a turbine rating of five. If it is a blended product, we are assuming that the resources are equivalent to a turbine. |
| 9 | Enron #5 Tolling | Rating=7<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 4th tier of nominal levelized cost: NLC=$(3.00)MWh to ($4.50)/MWh | Rating=10<br>Top credit rating. | Rating=5<br>Price reflect potential volatility of natural gas. | Rating=3<br>Requires a major expansion of NW Pipeline | Rating=7<br>Tolling tied to the Longview CCCT. Some dispatchability - but unspecified. Start-up charge to be negotiated. | Rating=4<br>Turbine project would normally get a 5 rating. However, this project rating reduced due to significant permitting hurdles. Permitting not started; but expect to avoid EFSEC process. |

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## 2nd Round Screening
## RFP Bid Evaluation Matrix Documentation

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| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 10 | Enron #6 Turnkey | Rating=6<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 5th tier of nominal levelized cost: NLC=$(4.50)MWh to ($6.50)/MWh | Rating=10<br>Top credit rating. | Rating=5<br>Price reflect potential volatility of natural gas. | Rating=3<br>Requires a major expansion of NW Pipeline | Rating=9<br>This is the Longview CCCT. We would own the plant. Highly dispatchable. BPA transmission required (unconstrained path). | Rating=4<br>Turbine project would normally get a 5 rating. However, this project rating reduced due to significant permitting hurdles. Permitting not started; but expect to avoid EFSEC process. |
| 11 | Newport NW Tolling | Rating=10<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 1st tier of nominal levelized cost: NLC is greater than zero | Rating=1<br>Lack of a proven track record. Lack of available current financial information. Lack of any credit rating at this time. | Rating=5<br>Price reflect potential volatility of natural gas. | Rating=3<br>Requires a major expansion of either NW Pipeline or PGT. | Rating=6<br>A unit contingent tolling bid. Daily dispatchability. Variable heat rate tied to output level. Single transmission contingency exposure. | Rating=3<br>Turbine project would normally get a 5 rating. However, this project rating reduced due to significant permitting hurdles. Need additional water rights and emission credits. |
| 12 | NW Geothermal Bid #1 | Rating=2<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 8th tier of nominal levelized cost: NLC=$(11.00)MWh to ($15.00)/MWh | Rating=5<br>Average credit. Would require more investigation. | Rating=10<br>No fuel price risk. | Rating=10<br>No specific information regarding possible degradation of the site. However, other sites have experienced degradation over time. Company has stated that we can reduce payments if output reduces. | Rating=3<br>Not dispatchable. Remote transmission with single contingency exposure. (More constant output production than hydro over a year.) | Rating=10<br>Top rating relative to other projects due to minimal environmental impacts. |

## 2nd Round Screening
## RFP Bid Evaluation Matrix Documentation

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| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 13 | Pacific Winds | Rating=1<br>The nominal levelized cost (NLC) of this bid is worse than ($15.00/MWh) below the base case. As such, it is significantly uneconomic compared to several other bids. This project will not be further evaluated. | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) |
| 14 | PG&E Bid #1 Flat Purchase | Rating=9<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 2nd tier of nominal levelized cost: NLC=$0MWh to ($2.00)/MWh | Rating=9<br>Avista's credit assessment rates this somewhat below the top. | Rating=10<br>Fixed price; no fuel risk. | Rating=10<br>No fuel transportation risk. | Rating=4<br>Market purchase. No dispatchability. BPA transmission assumed - unconstrained path. | Rating=5<br>Assigned all market power bids a turbine rating of five. If it is a blended product, we are assuming that the resources are equivalent to a turbine. |
| 15 | PG&E Bid #2 Monthly Purchase | Rating=1<br>We picked the least cost pricing structure between the other PG&E bids. As such this bid is not further evaluated. | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) |

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## 2nd Round Screening
## RFP Bid Evaluation Matrix Documentation

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October 1?, 2000

| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 16 | PG&E Bid #3 Weekly Purchase | Rating=1<br>We picked the least cost pricing structure between the other PG&E bids. As such this bid is not further evaluated. | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) | Rating=NE<br>(Not Evaluated) |
| 17 | PG&E Bid #4 Tolling, Umatilla | Rating=5<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 6th tier of nominal levelized cost: NLC=($6.50)MWh to ($9.00)/MWh | Rating=9<br>Top credit rating. | Rating=5<br>Price reflects potential volatility of natural gas. | Rating=10<br>No fuel transportation risk. | Rating=4<br>Tolling arrangement based on Umatilla plant. Monthly dispatchability. Down 45 business days per year for maintenance. BPA transmission - unconstrained path. | Rating=3<br>Turbine project would normally get a 5 rating. However, this project rating reduced due to significant permitting hurdles. It is just starting its permitting process. |
| 18 | Regional Power Bid | Rating=8<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 3rd tier of nominal levelized cost: NLC=($2.00)MWh to ($3.00)/MWh | Rating=5<br>Average rating. Need further investigation. | Rating=10<br>No fuel price risk. | Rating=10<br>Critical water year is 85% of normal on average. Some months are 70% of normal. This project requires 7 MW of back-up capacity firming. No actual water basin studies were provided; just representative basin studies. | Rating=4<br>Transmission availability is questionable. Not dispatchable. Remote transmission with single contingency exposure. | Rating=7<br>Consistent with national legislative initiatives, small hydro is ranked above gas turbine projects. No fish issues are affecting this project. However, permitting is not finalized (1 pt deduct) |

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## 2nd Round Screening
## RFP Bid Evaluation Matrix Documentation

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| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 19 | Sumas Bid #1 Tolling | Rating=5<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 6th tier of nominal levelized cost: NLC=($6.50)MWh to ($9.00)/MWh | Rating=5<br>Average rating. Need further investigation. | Rating=5<br>Price reflect potential volatility of natural gas | Rating=5<br>Transportation probably available at market rates. | Rating=7<br>Tolling sale. Unit contingent. Dispatchable - but unspecified constraints/costs. Transmission must go through Canada and the northern intertie. Possible transmission capacity constraints. | Rating=3<br>Turbine project would normally get a 5 rating. However, this project rating reduced due to significant permitting hurdles. Need transmission upgrade. |
| 20 | Sumas Bid #2 Gas tied to Wells | Rating=1<br>Price tied to natural gas prices. However, the price they provided was higher than our forward gas price curve. We picked the least cost pricing structure between the two Sumas bids. As such this bid is not further evaluated. | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] |
| 21 | Williams Bid #1 Flat Purchase | Rating=9<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 2nd tier of nominal levelized cost: NLC=$0MWh to ($2.00)/MWh | Rating=10<br>Top rating | Rating=10<br>Fixed price; no fuel risk. | Rating=10<br>No fuel transportation risk. | Rating=4<br>Market sale. Flat; no dispatchability. BPA transmission assumed - unconstrained path. | Rating=5<br>Assigned all market power bids a turbine rating of five. If it is a blended product, we are assuming that the resources are equivalent to a turbine. |



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## 2nd Round Screening
## RFP Bid Evaluation Matrix Documentation

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| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 22 | Williams Bid #2 Tolling | Rating=5<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 6th tier of nominal levelized cost: NLC=($6.50)MWh to ($9.00)/MWh | Rating=10<br>Top rating | Rating=5<br>Price reflects potential volatility of natural gas. Price reflects potential volatility of natural gas. | Rating=5<br>Transportation probably available at market rates. | Rating=7<br>Tolling. Market based. Daily dispatchability. Minimum 16 hour down-time. BPA transmission assumed - unconstrained path. | Rating=5<br>Assigned all market power bids a turbine rating of five. If it is a blended product, we are assuming that the resources are equivalent to a turbine. |
| 23 | Clearwater-Yanke Energy Bid #1 | Rating=1<br>At $60/MWh real, their price is at least 50% above the market. | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] | Rating=NE<br>[Not Evaluated] |
| 24 | RCT Upgrades | Rating=9<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 2nd tier of nominal levelized cost: NLC=$0MWh to ($2.00)/MWh | Rating=10<br>Top rating. | Rating=5<br>Price reflects potential volatility of natural gas. | Rating=5<br>Transportation probably available at market rates. | Rating=10<br>Units owned. Highly dispatchable. Integrated on Avista transmission. 4 SSCTs provide higher dispatch and maintenance any other option. | Rating=4<br>Permit in place but requires a modification. If we stay below 100 tons of emissions, the permit process is simplified. |

The following is a general outline as to how we applied point ratings.

**Economic Benefit:**

| Rating | General Rationale Behind Ratings: |
|---|---|
| 10 | Nominal Levelized Cost (NLC) > 0 compared to the base case (without the resource). |
| 9 | Nominal Levelized Cost (NLC) in the range of 0 to (2.0) compared to the base case (without the resource). |
| 8 | Nominal Levelized Cost (NLC) in the range of (2.0) to (3.0) compared to the base case (without the resource). |
| 7 | Nominal Levelized Cost (NLC) in the range of (3.0) to (4.5) compared to the base case (without the resource). |
| 6 | Nominal Levelized Cost (NLC) in the range of (4.5) to (6.5) compared to the base case (without the resource). |
| 5 | Nominal Levelized Cost (NLC) in the range of (6.5) to (9.0) compared to the base case (without the resource). |
| 4 | Nominal Levelized Cost (NLC) in the range of (9.0) to (11.0) compared to the base case (without the resource). |
| 2 | Nominal Levelized Cost (NLC) in the range of (11.0) to (15.0) compared to the base case (without the resource). |
| 1 | Nominal Levelized Cost (NLC) < (15.0) compared to the base case (without the resource). No further evaluation done due to poor economics. |

**Electric Factors:**

| Rating | General Rationale Behind Ratings: |
|---|---|
| 10 | Highly dispatchable resource; direct interconnection with Avista transmission system |
| 9 | Highly dispatchable resource; BPA transmission to Avista system on unconstrained path. |
| 8 | |
| 7 | Some dispatchability, but unspecified as to amount or cost; delivered to Avista system via BPA transmission – unconstrained path |
| 6 | Daily dispatchability – flat on preschedule basis; single contingency transmission exposure. |
| 5 | Monthly dispatchability – flat; BPA transmission – unconstrained path. |
| 4 | No dispatchability; BPA transmission – unconstrained; other unique constraints such as 45 business days of maintenance. |
| 3 | No dispatchability; unit contingent; single contingency transmission exposure |

Avista Corporation
2000 Request for Proposals
October 12, 2000

## Second Round Screening

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## RFP Evaluation Economics
## Base Case Price Forecasts

| Bid No. | Bidder | Project Type | Capacity (MW) | Term (years) | Bid Savings (Cost) NLC ($/MWh) | Bid Savings (Cost) RLC ($/MWh) | Bid Savings (Cost) NPV ($000s) | Total Project NLC ($/MWh) |
|---|---|---|---|---|---|---|---|---|
| 11 | Newport NW Tolling | Tolling - Unit Contingent | 300 | 20 | 0.20 | 0.20 | 3,845 | 46.9 |
| 24 | RCT Upgrades | Rathdrum Conversion w/4-LM6000s | 282 | Turnkey | (1.00) | (0.80) | (23,916) | 44.6 |
| 21 | William Energy Bid #1 Flat Purchase | Flat Purchase | 300 | 20 | (1.50) | (1.20) | (31,966) | 41.8 |
| 14 | PG&E Bid #1 Flat Purchase | Flat Purchase | 300 | 20 | (1.60) | (1.30) | (34,334) | 41.9 |
| 18 | Regional Power Bid | Small Hydroelectric | 21 | 20 | (2.10) | (1.70) | (1,921) | 43.0 |
| 9 | Enron #5 Tolling | Tolling - Unit Contingent | 249 | 20 | (4.00) | (3.20) | (65,791) | 46.0 |
| 5 | Enron Bid #1 20 Year Flat | Flat Contract | 100 | 20 | (5.30) | (4.20) | (37,123) | 45.6 |
| 10 | Enron #6 Turnkey | CCCT Turnkey | 249 | Turnkey | (5.30) | (4.20) | (86,432) | 47.2 |
| 2 | Continental Energy Tolling | Tolling - Unit Contingent | 300 | 20 | (8.10) | (6.40) | (157,341) | 47.5 |
| 22 | Williams Energy Bid #2 Tolling | Tolling - Unit Contingent - capped @ 6% FOR | 300 | 20 | (8.20) | (6.50) | (120,489) | 54.7 |
| 17 | PG&E Bid #4 Tolling, Umatilla | Tolling - Unit Contingent | 250 | 20 | (8.50) | (6.80) | (126,116) | 48.8 |
| 6 | Enron Bid #2 10 Year Purch | Flat Contract | 100 | 10 | (8.60) | (6.80) | (30,004) | 61.3 |
| 19 | Sumas Bid #1 Tolling | Tolling - Unit Contingent | 300 | 20 | (8.60) | (6.80) | (139,400) | 52.0 |
| 4 | Engage Bid Tolling | Tolling - Unit Contingent | 125 | 10 | (10.60) | (8.40) | (43,392) | 69.8 |
| 12 | NW Geothermal Bid #1 | Geothermal | 28 | 20 | (12.70) | (10.00) | (22,275) | 56.7 |
| 8 | Enron Bid #4 Monthly Dispatch | Monthly Tolling - firm | 100 | 10 | (13.90) | (11.00) | (42,762) | 69.3 |
| 1 | Calpine Bid Tolling | Tolling - Unit Contingent on AVA Site | 250 | 20 | (21.00) | (16.60) | (199,584) | 69.2 |
| 7 | Enron Bid #3 Quarterly Dispatch | Quarterly Dispatch | 100 | 10 | (31.00) | (24.50) | (54,018) | 75.9 |
| 3 | Empire Lumber Bid | Woodwaste | 9.9 | 20 | (36.60) | (28.90) | (24,556) | 76.9 |
| 13 | Pacific Winds | Wind | 71 | 20 | (60.90) | (48.20) | (98,271) | 103.9 |
| 15 | PG&E Bid #2 Monthly Purchase | Monthly Dispatch Purchase | 300 | 10 | | | | |
| 16 | PG&E Bid #3 Weekly Purchase | Weekly Dispatch Purchase | 300 | 10 | | | | |
| 20 | Sumas Bid #2 Gas tied to Wells | CCCT- Fixed Price Unit Contingent | 300 | 20 | | | | |
| 23 | Clearwater-Yanke Energy Bid #1 | Woodwaste | 1.85 | 5 | | | | |

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*Second Round Screening*

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## RFP Evaluation Economics
## Sensitivies to Price Forecasts

| Bid No. | Bidder | Project Type | Capacity (MW) | Term (years) | Marginal Impact to Avista Utilities' Portfolio: Base Case NLC ($/MWh) | Base Case RLC ($/MWh) | Base Case NPV ($000s) | Low Electricity NLC ($/MWh) | Low Electricity RLC ($/MWh) | Low Electricity NPV ($000s) | High Electricity NLC ($/MWh) | High Electricity RLC ($/MWh) | High Electricity NPV ($000s) | High Gas NLC ($/MWh) | High Gas RLC ($/MWh) | High Gas NPV ($000s) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | Newport NW Tolling | Tolling - Unit Contingent | 300.0 | 20 | 0.2 | 0.2 | 3,845 | (7.4) | (5.8) | (6,654) | 6.4 | 5.0 | 5,769 | (2.6) | (2.0) | (2,307) |
| 24 | RCT Upgrades | Rathdrum Conversion w/4 | 282.0 | Turnkey | (1.0) | (0.8) | (23,916) | (5.7) | (4.5) | (115,847) | 6.1 | 4.8 | 189,491 | (7.9) | (6.3) | (131,018) |
| 21 | William Energy Bid #1 Flat Purchase | Flat Purchase | 300.0 | 20 | (1.5) | (1.2) | (31,966) | (6.0) | (4.8) | (126,403) | 7.3 | 5.7 | 152,123 | (1.5) | (1.2) | (31,941) |
| 14 | PG&E Bid #1 Flat Purchase | Flat Purchase | 300.0 | 20 | (1.6) | (1.3) | (34,334) | (6.1) | (4.9) | (128,771) | 7.1 | 5.6 | 149,754 | (1.6) | (1.3) | (34,309) |
| 18 | Regional Power Bid | Small Hydroelectric | 21.0 | 20 | (2.1) | (1.7) | (1,921) | (9.1) | (7.2) | (162,559) | 5.4 | 4.2 | 107,751 | (12.1) | (9.6) | (176,475) |
| 2 | Continental Energy Tolling | Tolling - Unit Contingent | 300.0 | 20 | (8.1) | (6.4) | (157,341) | (15.3) | (12.1) | (183,486) | 2.3 | 1.8 | 42,271 | (18.8) | (14.8) | (194,287) |

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BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-6)

# REQUEST FOR PROPOSALS

**Evaluation of Resources**
**from Electric Energy Efficiency and/or**
**Power Supply Resources**

## Avista Corporation

## August 2000

## Introduction

Avista Corp. is seeking to identify resources that can become part of Avista's resource portfolio to meet its system requirements while at the same time minimize the cost of meeting those needs. Resources bid to Avista will be considered for purchase as part of the company's long-term resource portfolio for meeting customer needs. The company has identified a power need of approximately 300 megawatts (MW) of both capacity and corresponding energy. Resource availability in the year 2004 would fit Avista's requirements best. However, Avista does have significant resource needs in advance of this time frame. Bidders wanting more details regarding the timing of Avista's resource needs may request a copy of its "1997 Integrated Resource Plan Update".

The goal of the 2000 Request For Proposals (RFP) will be to identify low cost and environmentally sound resource options that best satisfy Avista's resource needs. This process will support the company's ongoing assessment of the cost and availability of new resources, and may provide input for Avista's 2000 Integrated Resource Plan (IRP). Resources bid to the company in response to this RFP must be competitive with other resource options available to Avista, including resources available at cost from affiliates, in order to be considered for purchase.

This RFP is an all-source process and bidders are encouraged to make proposals for energy efficiency resources or power supply resources. Avista encourages bidders with competitive renewable resource projects to consider bidding as a power supply resource. Proposals from energy efficiency measures will be competing against each other and power supply resources will be competing against other power supply resources. The most favorable resources bid to the company will also be compared with Avista's own potential or existing resource acquisition programs for either energy efficiency or power supply resources respectively. Avista has included information on its energy efficiency programs and on general power resource needs and costs in its "1997 Integrated Resource Plan Update".

## Avoided Cost

The following table represents costs that Avista might incur were it to construct a large combined-cycle combustion turbine. The avoided costs shown below for the next 20 years (excluding 2001) are based upon this resource assumption.

**Avista Utilities Avoided Cost Schedule**
**nominal dollars**

| Year | $/MWh | Year | $/MWh | Year | $/MWh | Year | $/MWh |
|---|---|---|---|---|---|---|---|
| 2001 | 60.0 | 2006 | 39.1 | 2011 | 44.2 | 2016 | 51.2 |
| 2002 | 37.8 | 2007 | 39.9 | 2012 | 45.4 | 2017 | 52.9 |
| 2003 | 37.7 | 2008 | 40.8 | 2013 | 46.7 | 2018 | 54.6 |
| 2004 | 38.0 | 2009 | 41.8 | 2014 | 48.2 | 2019 | 56.3 |
| 2005 | 38.4 | 2010 | 43.0 | 2015 | 49.7 | 2020 | 58.1 |

For 2001 the avoided cost value is based on actual broker quotes obtained July 24, 2000. Between 2002 and 2020, the figures are generated using a spreadsheet analysis prepared by the Northwest Power Planning Council (NWPPC). The spreadsheet was adjusted to reflect the NWPPC's *250 MW CC - Eastside Blk 1 Base* case, and one hundred percent investor-owned utility ownership. As shown, the avoided cost rises from $37.8 in 2002 to $58.1 in 2020.

The figures shown generally are representative of the costs that the Company might expect associated with the construction and operation of a combined-cycle combustion turbine. However, it is important to recognize that a number of variables might change, such as where the project ultimately is constructed.

Gas price assumptions can vary the project economics substantially. Natural gas prices were input into the NWPPC model using data from the Company's natural gas 2000 Integrated Resource Plan. These values are higher than the NWPPC's assumptions and drive costs up by about 5 percent in the first year.

Another important consideration is environmental compliance. Permitting processes and requirements for air quality, water and mitigation of other environmental impacts will also vary depending on the specific project location.

While the avoided cost figures shown above meet the requirements of WAC 480-170-050, the company expects the RFP results to provide a better measure of avoided costs going forward. As such, a given proposal that provides a cost stream below the costs shown above might not be selected. Similarly, where the RFP shows that general market conditions are higher than the above schedule, Avista may select a project with costs above the avoided cost schedule.

## General Considerations

The Company states certain resource preferences that would fit well into in its resource portfolio. However, bidders may submit proposals for projects of varying types or sizes, or at alternative sites. Timing of resources may vary from what is suggested as well. Each variation may have distinct pricing characteristics.

Potential resources will be considered for acquisition as part of the company's long term resource portfolio for meeting retail customer needs. The company will consider all relevant factors (including but not limited to price, dispatchability, transmission impacts, other bids, company-sponsored options, business and operating history of the project developer, and financial and rate impacts) in the bid resource evaluation. Resource proposals will be evaluated on the basis of the most current information available. Evaluation is discussed in more detail under both the energy efficiency and power supply sections.

Avista retains the right to reject any and all project proposals, at any time before execution of a written contract. Executed contracts may be submitted to the IPUC or WUTC for approval, as appropriate in Avista's judgement.

The bid term, or the length of time the electrical savings or electrical generation is being bid, shall be set forth in each proposal. However parties are advised that Avista is interested in long-term arrangements that will meet resource requirements for twenty years or more.

Aspects of the sponsor's proposal may be subject to negotiation to specifically define the operation of the proposed project, to insure adequate credit support for the prospective seller, and to insure that the delivered services will be consistent with Avista's needs. These negotiations will be important in shaping the quality of the bid services to ensure that they add value for the company. Negotiation with a given sponsor does not necessarily imply that such sponsor's proposal will be selected.

To review each proposal fairly and to determine which projects are likely to provide the best value to Avista's customers, Avista requires specific information regarding each proposed project.

**Proposal Preparation and Evaluation**

Project sponsors interested in responding to Avista's RFP must complete the appropriate forms and submit them according to the RFP schedule. Avista will commence its evaluation of the RFP submittal at the time of the bidding deadline as outlined in the Evaluation and Ranking sections under the Request for Energy Efficiency Resource Proposals and the Request for Power Supply Resources respectively. To assure full consideration of the bid, as well as to expedite the review process, please adhere to the RFP instructions and response format. It is important that all information requested in the RFP be complete and submitted by the bidding deadline. In the initial review of the bid proposals, if deficiencies are not material, Avista may, at its option, grant a limited extension to cure such deficiencies. Late or incomplete forms or proposals will result in the proposed project being eliminated from further consideration. All bids will be retained by Avista and will not be returned to project sponsors.

After completion of its initial evaluation process, Avista will notify those on a short list of bidders that their projects have been selected for further review and potential negotiation. Avista may meet with the short listed bidders. Bidders of those projects that are not selected will be so notified.

Avista may elect to negotiate certain aspects of the bidder's proposal. The bidder will be expected to remain prepared to deliver the services indicated in the proposal, subject to any changes mutually agreed to as part of the negotiation process. Failure to adhere to the original RFP will be justification for Avista to cease negotiations and to reject the proposal. Contracts may be subject to the approval of the IPUC and the WUTC, as appropriate.

Another key consideration is operating flexibility. Operating flexibility is represented by the project's compatibility with Avista's electric system and power supply. Timing of energy deliveries on a seasonal and daily basis is a measure of this criterion. Avista's ability to control project output levels is also important. These evaluation elements are further discussed in the Evaluation and Ranking sections under the Request for Energy Efficiency Resource Proposals and the Request for Power Supply Resources respectively

Avista retains sole discretion to determine which proposal best meets Avista's system requirements, and which will be selected for negotiation and further review. Avista will evaluate all proposals in the context of meeting overall least-cost objectives, which may take into account many factors, including but not limited to cost, risk, operating flexibility, diversity of supply, and any other relevant factors. Environmentally sound resources must meet all local, state, and federal agency requirements and, in the case of dedicated plant construction, the ability to handle local impact issues. The company will also be comparing bid proposals against its own programs and other proposed generation and energy efficiency resources.

Avista reserves the right to modify the RFP process to comply with any WUTC or IPUC orders, rules, regulations or guidelines.

If, upon review of the RFP, there are questions regarding completion of the RFP, please contact:

Avista Corp.<br>
P.O. Box 3727<br>
Spokane, WA 99220-3727

ATTN: 2000 Competitive Bid Proposal<br>
c/o Doug Young<br>
MSC-7

Schedule and Procedure

A. Milestone Schedule

| | |
|---|---|
| August 14, 2000 | RFP available to potential bidders |
| September 18, 2000 | Submittal to Avista of resource proposals |
| September 22, 2000 | Initial review completed by Avista |

| | |
|---|---|
| October 6, 2000 | Determination of preliminary short list<br>Notify project sponsors |
| October 20, 2000 | Complete meetings with project sponsors |
| October 24, 2000 | Selection of short list for negotiation |
| November 3, 2000 | Final selection (RFP decision) |

B. Submittal of Proposals. All project proposals must contain the information requested in this RFP and ten (10) copies must be submitted so as to be received by Avista no later than noon on September 18, 2000 at the following address:

Avista Corp.
E. 1411 Mission Avenue
Spokane, WA 99202

ATTN: 2000 Competitive Bid Proposal
c/o Doug Young
MSC-7

In accordance with WAC 480-107-070 (4), project proposals shall remain sealed until expiration of the solicitation period.

The preparation and submission of a project proposal will be at the expense of the project sponsor.

C. Modification or Withdrawal of Project Proposals
A sponsor of a project proposal may modify its project proposal by written request, provided that the request is received by Avista prior to September 18, 2000.

D. Initial Review of Project Proposals
Avista will perform an initial review of project proposals to determine if all required information has been provided. Avista expects to complete this initial review by September 22, 2000. Project sponsors who are not selected because of deficiencies in the response to the RFP will be so notified. Where such deficiencies are not material,

Avista may, at its option, grant an extension of seven (7) days to cure such deficiencies. Material deficiencies will disqualify a proposal from further consideration.

E. Confidentiality of Information

Avista may agree to keep confidential any document so designated by the participants in the bidding process. Inasmuch as project proposals are subject to examination by the WUTC pursuant to the WAC 480-107-070 (4), and by the IPUC, refusal to release confidential information to the WUTC or IPUC may adversely affect consideration of the project proposal.

Avista will take reasonable precautions and use reasonable efforts to protect confidential information, which is clearly identified as such on the page on which confidential material appears.

## LIMITATIONS

THERE SHALL BE NO BINDING CONTRACT UNTIL AVISTA AND THE PROJECT DEVELOPER HAVE EXECUTED A FINAL WRITTEN PURCHASE AND SALE AGREEMENT. THIS RFP DOES NOT CONSTITUTE AN OFFER BY AVISTA, AND SUBMITTAL OF A PROJECT PROPOSAL SHALL NOT BE DEEMED AN ACCEPTANCE. AVISTA RETAINS THE RIGHT IN ITS SOLE DISCRETION TO REJECT ANY AND ALL PROJECT PROPOSALS AT ANY TIME BEFORE EXECUTION OF A FINAL WRITTEN PURCHASE AND SALE AGREEMENT AND TO REVISE THE MILESTONE SCHEDULE SET FORTH HEREIN. AGREEMENTS MAY BE SUBMITTED TO THE IPUC AND/OR WUTC FOR APPROVAL, AS APPROPRIATE.

# Request for Energy Efficiency Resource Proposals

## General Overview

Avista currently provides a variety of energy efficiency services to the Company's retail electric customers in all market segments. These services are currently funded through a special Tariff Rider approved by both the Washington and Idaho State Commissions. As the Company prepares to enter a period of potential energy deficiency, Avista is assessing the addition of energy efficiency activity, incremental to the current acquisition goal of 3 aMW per year, through a bidding process.

Avista's interest is in the acquisition of cost-effective energy efficiency and system capacity resources that positively contribute to our existing portfolio attributes. As such, the Company is seeking programs that incur the least amount of utility and total resource cost to acquire a desired level of electric efficiency or system capacity resources.

## General Bidding Guidelines

All energy efficiency proposals shall, at a minimum, satisfy the requirements of WAC 480-107-030. A bidder must either be an Avista retail electric customer or a contractor proposing one or more projects at the site of an Avista retail electric customer. Project proposals must yield annual electricity savings of at least 2,190,000 kWh (250 aKW). The energy saving measures must be installed over a period of not more than three years. Savings from installed measures must persist for a period of at least five years. Project proposals selected under this RFP are not eligible for grants, loans, or other payments under any other Avista sponsored energy efficiency program during the life of the proposed project.

Bids may include electric efficiency projects or fuel conversion projects involving the replacement of electric end-use equipment with equipment using natural gas (natural gas equipment must be at least 45 percent efficient). Bids may not include the substitution of alternative supplies of electricity or provide savings through the curtailment or cessation of end-uses. Electric energy savings must not result in significant reduction to the quality of end-use processes or products.

Avista will view some measures more favorably than others in the selection process. Unfavorable reviews would result from questionable assurance of savings, lack of savings persistence, degradation of savings, or concentration of measures at a single or small number of host facilities.

It is also required that all emissions credits accrued through electric energy savings resulting from the implementation of proposed energy efficiency measures become the sole property of Avista Corporation unless other arrangements are explicitly included in the final contract.

**Proposal Contents**

Following is a list of general topics that each proposal should address. Within each area are specific requests for information about each proposal. A written response to each specific request should be provided. If a request does not apply to a proposal, a written response is required which sets forth which requests are not applicable and a brief explanation as to why.

A. Description of Proposal

1. Describe the proposed energy efficiency measure(s) and the specific customer or customer type(s) and building type(s) where the measures will be located.
2. Provide an estimate of the projected annual electric energy savings and system capacity savings of the project when completed. Provide a detail of unit savings used to derive the total savings estimates, and the basis for those estimates. Provide a monthly distribution of those savings. If

system capacity savings are proposed, provide a description of what hour those savings are available or alternatively an hourly shape of savings. Provide an estimate of the monthly and annual load factors of savings for all measures.

3. Provide a description of dispatchability (or similar utility control), if any, of the project savings. This will probably apply only to measures incorporating system capacity savings.
4. Provide an estimate of the physical life and useful life each measure in the project proposal. Describe any maintenance and replacement requirements or savings of the measure(s).
5. Provide a timeline for project completion, with an estimate of savings achieved for each month until project completion.
6. Describe who is to own and operate the energy efficiency or system capacity efficiency measure(s) after they are installed.
7. List and describe who is to install the measure(s), including any installation subcontractors.
8. To the extent possible, describe and support any reasons that the bid proposal may better benefit Avista and its customers than the Company's existing energy efficiency programs if that proposal is partially or entirely mutually exclusive with an existing program.

B. Price and Payment Structure. The price bid, the requested pricing configuration, and terms of the proposed services are subject to negotiation.

1. Provide a detailed description of the price of the proposal, including amount per unit and timing of payments. Bid price can be based upon annual payments, or initial payment per kWh or kW saved, or initial payment per measure installed.
2. Detail any portion of the payment to be based on measured performance. Detail any portion of the payment to be based on other criteria. Performance-based pricing structures are preferred but not rigidly required.

3. Describe the proposed payment plan, including when payment for savings will be made, the conditions that must be met before payment is made, and how payments may be adjusted following any verification of savings procedures.

4. Provide an estimate and description of fees, shared savings arrangements, or any other contribution the customer or third party will be obligated to pay for the installation of any portion of the proposed measure(s).

5. Provide a calculation showing the utility costs of the proposal.

C. Savings Verification Plan.

1. Describe the procedures that will be used to estimate and measure savings from the installed measures. For estimates that are to be made, describe how they are derived and the assumptions and sources used to develop the estimates. For savings that are to be measured, describe the proposed measurement procedures. Provide sufficient detail on the measurement procedures, including the type of measurement (i.e., billing analysis or end-use metering) and the participants included in the measurement. The savings verification plan should address both first year annual savings and savings persistent over the proposed life of the measure. Describe any plans to verify estimated savings. Describe any procedures that will be in place to measure the persistence of the energy savings.

2. Describe Avista's role in the proposed verification plans. Describe any information, data, or support that Avista will need to provide to the verification plan.

3. Describe the timeline for savings verification. Specifically describe the links between measure installation, verification of savings and payment.

4. Provide a proposal for assessing the level of free-ridership resulting from the proposal. Free-riders are generally defined as program participants who would have adopted the measure(s) in the absence of the proposed program.

D. Marketing and Customer Service Plan.

1. Provide a description of the marketing plan that will be used to recruit participants, if appropriate. Describe how customers will be contacted and how eligibility for participation will be determined.
2. Describe how your proposal is designed to minimize the level of free-ridership. This may include a description of how participants will be recruited and the expected simple payback for participants with and without financial incentives. (Simple payback is to be calculated as the participant's cost divided by the annual energy bill savings.)
3. Describe how participant complaints will be addressed.
4. Describe any general marketing assistance the bidder expects Avista to provide. This may include customer lists, customer billing records, letters of introduction, or support by the Company's customer service representatives.
5. Describe written or implied warranties that will be provided to customers regarding quality of materials and installation.
6. Any bidders currently operating programs will be required to provide Avista with information on participants, measures installed, estimated energy savings, system capacity impact, and participant costs. Describe the intention to track and provide that information to Avista.
7. List complaints received from participants regarding the conduct of past energy or capacity efficiency programs by the bidder and the disposition of each complaint.

E. Financial Capability

1. Provide a description of plans for financing the energy efficiency project(s).
2. If your proposal requires liquidated damages, describe the proposed security arrangements (i.e., bank letter of credit, payment bond, corporate guarantee, or other security).

3. Be prepared to provide, if the proposal is selected for negotiation, a demonstration of the ability to obtain a level of insurance, such as general business and liability insurance, sufficient to cover major project contingencies.

F. General Qualifications

1. Please be prepared to provide three or more references from the last five jobs where the bidder has performed similar services to those proposed to Avista if the proposal is selected for negotiation. These references can be a contact person at another utility to whom the bidder has provided services, or electric customers for whom the bidder has provided energy efficiency services, preferably similar to those included in the bidder's proposal. Provide telephone numbers for these references.
2. Provide a general description of the your organizations background and experience in projects similar to your proposal.
3. Be prepared to list and describe, if the proposal is selected for negotiation, any licenses that you or your subcontractors have or will be required to obtain to perform the type of work described in your proposal.
4. Be prepared to describe, if the proposal is selected for negotiation, how your proposal complies with all applicable codes, permits and licenses legally required for the measure installations proposed. A list of the necessary permits will also be required during negotiation.
5. Provide form of business classification (i.e., sole proprietorship, partnership, or corporation).
6. Be prepared to list, if the proposal is selected for negotiation, all affiliated companies, including holding companies, subsidiaries, and predecessor companies presently or in the past engaged in delivering the types of services included in the proposal.
7. Provide a list of prior organizations for which key management team members have worked if such organizations have provided services similar to those in the proposal.

8. Be prepared to list all lawsuits, regulatory proceedings, or arbitration in which the bidder or its affiliates or predecessors have been engaged related to the types of services proposed if the proposal is selected for negotiation. Identify the parties involved in such lawsuits, proceedings, or arbitration, and the final resolution or present status of such matters.
9. Detail the disposal of waste to be removed from customer facilities as part of energy efficiency projects, including the disposal of toxic and contaminated waste. Describe any recycling strategies to be incorporated into disposing of removed materials from the project.
10. Detail specific environmental aspects of the project, including any planned utilization of recycled materials in equipment supplied to the project.

## Evaluation and Ranking of Energy Efficiency Proposals

All energy efficiency and system capacity proposals will be evaluated and ranked against the other proposals submitted. The review and possible selection of projects will be based on which proposal(s) provide the optimum value to Avista's customers. Proposals will first be screened to ensure that they meet required criteria as stated in this RFP and have completed the "Checklist For Energy Efficiency and System Capacity Resources".

A preliminary evaluation will follow the initial screening to narrow the list. The evaluation will be based upon both price and non-price criteria. The pricing evaluation will consider measure persistence, timing and flexibility of capacity delivery, degradation of savings, program free-ridership and market transformation. Evaluation of non-price factors will include, but will not be limited to, the economic value to participating customers and the compatibility of the program with Avista's overall energy efficiency portfolio.

Next, a detailed evaluation of selected proposals will take place and could include meetings with bidders. Following the detailed evaluation will be the selection of proposals for negotiation. Negotiation does not guarantee an award of a written contract.

Due to the individual and unique nature of each bid, evaluation and ranking will include the balancing the various impacts of the criteria bid. The six categories that will be used in the proposal ranking will be the description of proposal, price and payment structure, savings verification plan, marketing and customer service plan, financial capability, and general qualifications and references.

If any proposal receives an unacceptable rating in any category, Avista may, at its sole discretion, eliminate that proposal from further review. However Avista, at the discretion of reviewers, may request a bidder to correct minor deficiencies in order for the bid to receive an overall acceptable rating.

## CHECK LIST FOR ENERGY EFFICIENCY AND SYSTEM CAPACITY RESOURCES

To be completed for all bid proposals. Please check in the space provided if the applicable exhibit is attached.

GENERAL INFORMATION
Project Sponsor's Name:
Address:
Phone Number:

PROJECT INFORMATION
Project Location:
Annual Energy Capability (MWh):
Term of Sale:
Date of First Installation:

| DESCRIPTION OF PROPOSAL | | |
|---|---|---|
| Description of Measures | A.1. | _____ |
| Estimated Savings | A.2. | _____ |
| Physical & Useful Life | A.3. | _____ |
| Dispatchability | A.4. | _____ |
| Timeline | A.5. | _____ |
| Owner & Operator | A.6. | _____ |
| Subcontractors | A.7. | _____ |
| Why Use Your Proposal | A.8. | _____ |

| PRICE AND PAYMENT STRUCTURE | | |
|---|---|---|
| Description of Price | B.1. | _____ |
| Measured Performance | B.2. | _____ |
| Payment Plan | B.3. | _____ |
| Fee or Shared Savings | B.4. | _____ |
| Utility Cost | B.5. | _____ |

| SAVINGS VERIFICATION PLAN | | |
|---|---|---|
| Description of Plan | C.1. | _____ |
| Avista's Role | C.2. | _____ |
| Timeline | C.3. | _____ |
| Free-ridership | C.4. | _____ |

| MARKETING AND CUSTOMER SERVICE PLAN | | |
|---|---|---|
| Description of Marketing Plan | D.1. | _____ |
| Free Riders | D.2. | _____ |
| Complaints Procedure | D.3. | _____ |
| Avista's Role | D.4. | _____ |
| Warranties | D.5. | _____ |
| Data Gathering | D.6. | _____ |
| List of Complaints | D.7. | _____ |

| FINANCIAL CAPABILITY | | |
|---|---|---|
| Description of Plan | E.1. | _____ |
| Liquidated Damages | E.2. | _____ |
| Insurance | E.3. | _____ |

| GENERAL QUALIFICATIONS | | |
|---|---|---|
| References | F.1. | _____ |
| Experience | F.2. | _____ |

| | | |
|---|---|---|
| Licenses | F.3. | _____ |
| Codes and Permits | F.4. | _____ |
| Business Classification | F.5. | _____ |
| Affiliated Companies | F.6. | _____ |
| Key Individuals | F.7. | _____ |
| Lawsuits | F.8. | _____ |
| Waste Disposal | F.9. | _____ |
| Environmental Aspects | F.10. | _____ |

# Request for Power Supply Resources

## General Discussion

Avista has identified the need for 300 MW of capacity and 300 MW of average energy. Resource availability in the year 2004 would fit Avista's requirements best. However, Avista does have significant resource needs in advance of this time frame and will evaluate proposals with different starting dates. Each proposal shall set forth a term. However, Avista is interested in long-term arrangements that will meet resource requirements of twenty years or more. Avista desires to acquire operating flexibility in this power supply. Therefore, additional value will be placed on power supplies with the following attributes:

- Firm delivery backed by a generating resource or a composite of resources preferably within the Northwest Region.
- Price capped to emulate the cost from a generating resource.
- Curtailment capability to allow Avista an opportunity to stop deliveries. If deliveries from a project may be curtained at Avista's option, Avista would have the opportunity to purchase power from the wholesale electric market when the market price is less expensive than the firm purchased power supply.
- The ability to quickly make changes in delivery (ramp-up and ramp-down) in order to follow variable load obligations.

Avista's objective is to find the most economical option to fulfill this resource requirement. All bids will be evaluated based on their cost, flexibility service provided and overall usefulness to Avista. Avista invites proposals on the various options described under "Bids Requested". Avista has listed a separate option under "Bids Requested" in order encourage bids for cost-effective renewable resource proposals. Avista also welcomes your ideas that you may feel better meet the objective of this RFP.

## Point of Delivery

Specify the point of delivery for each product offered. If the point of delivery is at a point other than Avista's system, Avista will add transmission costs to deliver the product to its system. If Avista is not the holder of the contract for third party transmission, Avista will place additional value on options to move the delivery point within the Northwest Region on a non-firm or as available firm basis. However, Avista prefers to hold the contract for third party transmission, if required to deliver the power. Direct delivery to Avista's system can be made at the following points:

1. Wanapum – interconnection with multiple parties at mid-Columbia
2. Westside - BPA interconnection
3. Bell – BPA interconnection
4. Hatwai – BPA interconnection
5. Hot Springs – BPA and Montana interconnection
6. Lolo – Idaho interconnection
7. Other points will be considered

For purposes of responding to this RFP, assume that adequate transmission capacity exists at Avista's points of delivery listed above. Transmission limitations (if any) will be considered in subsequent steps of the selection process.

## General Qualifications List

A. Please provide three or more references from the last five projects where the bidder, or its affiliates, if appropriate, have implemented a power supply proposal similar to those proposed to Avista. These references can be a contact person with whom the bidder has transacted business. Provide telephone numbers for these references.

B. Provide a general description of the bidder's background and experience in power supply proposals similar to its proposal.

C. Provide form of business classification (i.e., sole proprietorship, partnership, or corporation).

D. List all affiliated companies, including holding companies, subsidiaries, and predecessor companies presently or in the past engaged in developing and/or implementing power supply proposals.

E. Provide a list of prior organizations for which key management team members have worked if such organizations have developed and/or implemented power supply proposals.

F. List all lawsuits, regulatory proceedings, or arbitration in which the bidder or its affiliates or predecessors have been engaged related to the types of power supply proposals proposed. Identify the parties involved in such lawsuits, proceedings, or arbitration, and the final resolution or present status of such matters.

G. Detail specific environmental aspects of the power supply proposal.

H. Provide a statement of responding companies financial status and ability to obtain financing.

I. Provide a list of any current credit issues raised by rating agencies, banks, or accounting firms. Provide credit rating if available.

## Evaluation and Ranking of Power Supply Proposals

All power supply proposals will be evaluated and ranked against the other power supply proposals submitted. The review and possible selection of power supply will be based on which proposals can provide optimum value to Avista's customers.

Proposals will first be screened to ensure they meet required criteria as stated in this RFP and have completed the applicable sections of the "Checklist For Power Supply Resources". General Qualifications must be provided as outlined above plus the project specific information requested for each proposal submitted under the respective section of "Bids Requested". A preliminary evaluation will follow the initial screening to narrow the list. Evaluation will be based upon both price and non-price criteria. Renewable Energy projects will receive a 10% credit on price to account for reduced air quality impact and other environmental impacts. The evaluation will be split into the following three principle areas for evaluation: Electric Power Characteristics including ability of the project to meet size, dispatchability, fuel supply, timeline and other characteristics of Avista's need described in this RFP and in its "1997 Integrated Resource Plan Update" and the ability of the operator to meet construction and operational commitments; Financial/ Price Characteristics including demonstrated adequacy of financial capability to construct and maintain projects; Social/Environmental Characteristics including using reasonably current available environmental mitigation technology and ability to meet local, state, and federal agency requirements and, in the case of dedicated plant construction, the ability to handle local impact issues. Next, a detailed evaluation of selected proposals will take place. Following the detailed evaluation will be the selection of proposals for negotiation. Negotiation does not guarantee an award of a written contract.

Due to the individual and unique nature of each bid, the evaluation and ranking will include balancing the various impacts of the criteria bid including but not limited to price and payment structure, financial capability, and general qualifications and references.

If any proposal receives an unacceptable rating in any category Avista may, at its sole discretion, eliminate that proposal from further review. However Avista, at the discretion of reviewers, may request a bidder to correct minor deficiencies in order for the bid to receive an overall acceptable rating.

**Bids Requested**

Avista will consider all power supply proposals. In particular it is interested in receiving proposals of the types described below:

***I. Capacity & Energy Purchase.***

Avista will evaluate a purchase of a firm capacity and energy product. A power sale to Avista should be a firm product with interruption rights only for force-majeure conditions. This product may be purchased in increments that total up to 300 MW of capacity and energy.

Items to include in bid relating to "Capacity & Energy Purchase":

1. The source of the energy supply, for example, a generating plant dedicated solely to this sale, a composite or system of generating plants, the market.
2. Supplier curtailment rights.
3. Avista's curtailment rights, for example; right to purchase lower cost alternatives, to follow load reductions.
4. Flexibility that allows Avista to make quick changes in delivery to follow variable load obligations.
5. Control area of origin.

Sale scenarios may include:

A. January 1, 2004 – December 31, 2023 300 MW all hours - flat;

B. January 1, 2004 – December 31, 2023 300 MW, but Avista has dispatch rights.

***II. Qualifying Facilities with a generating capacity of less than one megawatt.***

Sponsors of Qualifying Facilities under the Public Utilities Regulatory Policies Act of 1978 (PURPA) with a generating capacity of less than one (1) MW of installed capacity are eligible to enter into long-run or short-run (energy only) contracts without submitting a bid pursuant to the RFP. Sponsors should contact Avista to obtain a copy of Avista's long-run or short-run prototype contracts.

### *III. Qualifying Facilities with a generating capacity of more than one megawatt.*

Sponsors of Qualifying Facilities under PURPA with a generating capacity of more than one megawatt are eligible to enter into short-run contracts (energy only) without submitting a bid pursuant to the RFP. Sponsors should contact Avista to obtain a copy of Avista's short-run prototype contract. Sponsors of Qualifying Facilities under PURPA with a generating capacity of more than one megawatt that desire to enter into long-run contracts are invited to submit bids in accordance with this RFP.

### *IV. Renewable Power Supplies.*

Renewable project developers are invited to make bids from competitive renewable resource projects. Avista is looking for competitive proven technology based proposals. Avista would like to evaluate both proposals for power delivery from renewable power projects and proposals for Avista ownership of a portion of or all of a renewable power project. Bidders should provide at a minimum, the following information about their project.

A. Description of Proposal

1. Describe the proposed specific renewable resource project. Describe the nature and characteristics of that project including location and power interconnection and transmission arrangements. Provide information regarding project ownership and operation.
2. Provide an estimate of the projected capacity and energy from the project. Provide information regarding when specific amounts of capacity and energy will be available. Provide a monthly distribution of energy production. If capacity will be provided, provide a description of what hours that capacity will be available firm or alternatively an hourly shape of available firm capacity. Provide an estimate of the monthly and annual plant factors.
3. Provide a description of dispatchability (or similar utility control), if any, of the project energy output. This will probably apply only to projects with capacity.

4. Describe when project power will be made available including any project timelines that may be applicable. Describe any variables that could affect those timelines.

## *V. Power Plant Site.*

### A. Combined Cycle Combustion Turbine

Avista would like to evaluate the construction of a 260 MW (nominal) natural gas fired Combined Cycle Combustion Turbine power plant. Avista would like to have parties bid sites for this construction in the Northwest region. A site offer should include all electric transmission necessary to connect the plant with the main power grid and all natural gas transmission necessary to interconnect the plant with interstate natural gas transmission facilities. In addition, information regarding each of the following must be included in the proposal:

1. Water supply characteristics, including: source; quality; and quantity.
2. Waste disposal characteristics, including: requirements; and treatment facility.
3. Work force characteristics, including:
    a) where it originates from to support construction;
    b) where it originates from to support operation;
    c) community infrastructure;
    d) what the surrounding community offers to support construction; and operation.
4. Community support, including political environment.
5. Transportation infrastructure, including, highways, railroads and airports.
6. Permits in General. The proposed site should have a complete description and listing of all permits acquired, pending and permits that must be acquired before the 260 MW (nominal) combined cycle combustion turbine can be built.

7. Air Permit. The air permit should be included with the RFP or described in detail. An itemized listing of the conditions under which the project is subject to operate must be attached. This assumes construction of a combined cycle combustion turbine with a output of 260 MW (nominal). The list must include but not be limited to the maximum each pollutant can emit by hour, year, etc.
8. A legal description of the proposed site.
9. Documentation of support for the project from local residents, state, local and federal agencies, and local political groups.
10. Documentation describing all opposition to the proposed development whether it is formal or informal.
11. Land and resource use considerations including, existing land use, cultural resources, earth resources and critical habitat.
12. All other attributes your site possesses that would make siting a combined cycle combustion turbine a positive decision.
13. Demonstration that the combined cycle combustion turbine project is licensable and operational under applicable site constraints.

B. Simple Cycle Combustion Turbine

Avista would like to evaluate the construction of up to 172 MW (nominal) of natural gas fired Simple Cycle Combustion Turbine power plants. Avista would like to have parties bid sites for this construction in the Northwest region. A site offer should include all electric transmission necessary to connect the plant with the main power grid and all natural gas transmission necessary to interconnect the plant with interstate natural gas transmission facilities. In addition, information regarding each of the following must be included in the proposal:

1. Water supply characteristics, including: source; quality; and quantity.
2. Waste disposal characteristics, including: requirements; and treatment facility.

3. Work force characteristics, including:
    a) where it originates from to support construction;
    b) where it originates from to support operation;
    c) community infrastructure;
    d) what the surrounding community offers to support construction; and operation.
4. Community support, including political environment.
5. Transportation infrastructure, including, highways, railroads and airports.
6. Permits in General. The proposed site should have a complete description and listing of all permits acquired or pending and permits that must be acquired before the 172 MW (nominal) simple cycle combustion turbines can be built.
7. Air Permits. The air permit should be included with the RFP or described in detail. An itemized listing of the conditions under which the project is subject to operate must be attached, this assumes construction of simple cycle combustion turbines with a output of 172 MW (nominal) must be included. The list must include but not be limited to the maximum each pollutant can emit by hour, year, etc.
8. A legal description of the proposed site.
9. Documentation of support for the project from local residents, state, local and federal agencies, and local political groups.
10. Documentation describing all opposition to the proposed development.
11. Land and resource use considerations including, existing land use, cultural resources, earth resources and critical habitat.
12. All other attributes your site possesses that would make siting a simple combustion turbine a positive decision.
13. Demonstration that the ~~combined~~ cycle combustion turbine project is licensable and operational under applicable site constraints.

## *VI. Turnkey Power Plants On Avista's Site.*

### A. Combined Cycle Combustion Turbine

Avista would like to evaluate the purchase of a turnkey 260 MW (nominal) natural gas fired Combined Cycle Combustion Turbine power plant located on a site provided by Avista. Please describe any variables that would change the ultimate cost to Avista which are dependent on the location of the plant. (Sales tax is an example.)

1. General Description. The following is a general description of the facility that is to be built and does not intend to describe all materials, equipment, facilities and manpower necessary for a completed facility to operate as described:
   - 1.1 One advanced technology combustion turbine and generator (CTG) based upon GE 7FA or equal. Unit should have inlet-cooling capabilities.
   - 1.2 One heat recovery steam generator (HRSG). Unit should have duct firing capabilities.
   - 1.3 One steam turbine and generator (STG).
   - 1.4 Associated balance of plant equipment.
   - 1.5 CTG will have only natural gas capabilities.
   - 1.6 The gas turbine will be equipped with a dry lo Nox combustion system.
     - a) Nox limits will be 9 ppm at 15% O2 on natural gas for the CTG
     - b) CO limits will be 9 ppm at 15% O2 on Natural gas for the CTG
   - 1.7 SCR will be added if required to meet additional permit requirements for Nox emissions.
   - 1.8 CO catalyst will be added if required to meet additional permit requirements for CO emissions.
   - 1.9 The CTG will be coupled to a synchronous hydrogen cooled or TEWAC (totally enclosed water to air cooled) generator.
   - 1.10 Plant shall also include a control system, inlet air system, lubrication oil system, hydraulic oil system and any other miscellaneous equipment necessary to support its operation.

1.11 Exhaust gas from the CTG shall be ducted into the HRSG to effectively recover the waste heat.

1.12 Transformers to step up the generation to 230 kv (configuration to be evaluated).

1.13 Other supporting equipment to provide safe and efficient operation shall include but not be limited to:

a) A demin system to meet the plant requirements
b) Cranes to perform required maintenance
c) Buildings to protect equipment
d) A DCS
e) Main surface condenser
f) Mechanical draft cooling tower
g) Boiler feed water pumps
h) Generator circuit breakers
i) Power centers
j) Motor control centers
k) Spare parts

2. Specifics of Site. It may be assumed that Avista will provide electric transmission to the property line and gas transmission to the property line. Also, it may be assumed that Avista will provide a suitable piece of property. The following site conditions will be assumed for the installation and design of a combined cycle combustion turbine on Avista's site:

| | |
|---|---|
| Soil bearing | 4000 psf |
| Wind velocity | 100 mph |
| Snow load | 50 psf |
| Rainfall in a 24 hour period | 1 inch |
| Maximum temperature | plus 100 degrees F |
| Minimum temperature | minus 30 degrees F |
| Approximate site elevation | 2000 feet above sea level |
| Approximate humidity | 60% |

3. This power plant should have inlet cooling and duct firing capabilities. Avista would plan to start and stop this plant 50 to 100 times per year. The majority of these starts would be considered hot starts, since the plant may be run for 16 hours during the day and shutdown to no load for 8 hours each night. The duct fired option may be used up to 8000 hours per year. Avista also prefers to have the ability to operate this plant on load control to follow variable load obligations. Avista will require input and review during design and construction of the project. Items of importance will include design and construction timelines, online date, heat rate curves, peak output, ramp rates, var capability, maintenance schedules and costs, recommended operation and maintenance staff, spare parts inventory and cost, type and availability of equipment and training programs. The design of the plant from an aesthetic point of view will be considered.

4. Sponsors should describe the number and qualifications of employees required to operate proposed facilities.

B. Simple Cycle Combustion Turbine

Avista would like to evaluate the purchase of turnkey natural gas fired Simple Cycle Combustion Turbine power plants of up to 172 MW sited on a site provided by Avista. The type and number of simple cycle combustion turbines will be evaluated. Please describe any variables that would change the ultimate cost to Avista which are dependent on the location of the plant. (Sales tax is an example.)

1. General Description. The following is a general description of the facility that is to be built and does not intend to describe all materials, equipment and facilities necessary for a completed facility to operate as described:

   1.1 Advanced technology combustion turbines and generators (CTG).
   1.2 Associated balance of plant equipment.

1.3 CTG will have only natural gas capabilities.

1.4 The gas turbine will be equipped with a dry lo Nox combustion system

a) Nox limits will be 25 ppm at 15% O2 on natural gas for the CTG

b) CO limits will be 9 ppm at 15% O2 on Natural gas for the CTG

1.5 SCR or equal will be added if required to meet additional permit requirements for Nox emissions.

1.6 CO catalyst will be added if required to meet additional permit requirements for CO emissions.

1.7 The CTG will be coupled to a generator (type to be evaluated).

1.8 Plant shall also include a control system, inlet air system, lubrication oil system, hydraulic oil system and any other miscellaneous equipment necessary to support its operation.

1.9 Transformers to step up the generation (configuration to be evaluated).

1.10 Other supporting equipment to provide safe and efficient operation shall include but not be limited to:

a) A demin system to meet the plant requirements if required

b) Cranes to perform required maintenance

c) Buildings to protect equipment

d) A DCS

e) Generator circuit breakers

f) Power centers

g) Motor control centers

h) Spare parts

2. Specifics of Site. It may be assumed that Avista will provide electric transmission to the property line and gas transmission to the property line. Also, it may be assumed that Avista will provide a suitable piece of property. The following site conditions will be assumed for the installation and design of a simple cycle combustion turbine on Avista's site:

| | |
|---|---|
| Soil bearing | 4000 psf |
| Wind velocity | 100 mph |
| Snow load | 50 psf |
| Rainfall in a 24 hour period | 1 inch |
| Maximum temperature | plus 100 degrees F |
| Minimum temperature | minus 30 degrees F |
| Approximate site elevation | 2000 feet above sea level |
| Approximate humidity | 60% |

3. This power plant should have inlet cooling and duct firing capabilities. Avista may plan to start and stop this plant 200 times per year. The majority of these starts would be after a 16 hour run with a 4 to 8 hour cool-down period before starting again. Avista also prefers to have the ability to operate this plant on load control to follow variable load obligations. Avista will require input and review during design and construction of the project. Items of importance will include design and construction timelines, online date, heat rate curves, peak output, ramp rates, var capability, maintenance schedules and costs, recommended operation and maintenance staff, spare parts inventory and cost, type and availability of equipment and training programs. The design of the plant from an aesthetic point of view will be considered.

4. Sponsors should describe the number and qualification of employees required to operate proposed facilities.

## *VII. Turnkey Power Plant Including Site.*

A. Combined Cycle Combustion Turbine

Avista would like to evaluate the purchase of a turnkey 260 MW (nominal) Combined Cycle Combustion Turbine power plant including the site. The proposal should describe the general site characteristics as set forth in Section ***IV,*** above. The power plant should have the same general characteristics as set forth in Section ***V***.A, above.

B. Simple Cycle Combustion Turbine

Avista will evaluate the purchase of turnkey Simple Cycle Combustion Turbine power plants including the site for up to 172 MW (nominal). The proposal should describe the general site characteristics as set forth in Section ***IV,*** above. The power plant should have the same general characteristics as set forth in Section ***V***.B, above.

## CHECK LIST FOR POWER SUPPLY RESOURCES

To be completed for all bid proposals. Please check in the space provided if the applicable exhibit is attached.

GENERAL INFORMATION

Project Sponsor's Name:

Address:

Phone Number:

PROJECT INFORMATION

Project Location:

Nameplate Rating (MW):

Annual Energy Capability (MWh):

Term of Sale:

Date of First Delivery (Commercial Operation):

Major Fuel Type:

Ownership:

DESCRIPTION OF PROPOSAL

I. Capacity & Energy Purchase

A.1. _____

A.2. _____

A.3. _____

A.4. _____

A.5. _____

B.1. _____

B.2. _____

B.3. _____

B.4. _____

B.5. _____

II. Qualifying Facilities with a generating capacity of less than one megawatt

_____

III. Qualifying Facilities with a generating capacity of more than one megawatt

_____

IV. Renewable Power Supplies

A.1. _____

A.2. _____

A.3. _____

A.4. _____

V. Power Plant Including Site

A. Combined Cycle Combustion Turbine

A.1. _____

A.2. _____

A.3. _____

A.4. _____

A.5. _____

A.6. _____

A.7. _____

A.8. _____

A.9. _____

A.10. _____

A.11. _____

A.12. _____

A.13. _____

B. Simple Cycle Combustion Turbine

B.1. _____
B.2. _____
B.3. _____
B.4. _____
B.5. _____
B.6. _____
B.7. _____
B.8. _____
B.9. _____
B.10. _____
B.11. _____
B.12. _____
B.13. _____

VI. Turnkey Power Plants On Avista's Site

A. Combined Cycle Combustion Turbine

A.1.1. _____
A.1.2. _____
A.1.3. _____
A.1.4. _____
A.1.5. _____
A.1.6. _____
A.1.7. _____
A.1.8. _____
A.1.9. _____
A.1.10. _____
A.1.11. _____
A.1.12. _____
A.1.13. _____

A.2. _____
A.3. _____
A.4. _____

B. Simple Cycle Combustion Turbine

B.1.1. _____
B.1.2. _____
B.1.3. _____
B.1.4. _____
B.1.5. _____
B.1.6. _____
B.1.7. _____
B.1.8. _____
B.1.9. _____
B.1.10. _____

B.2. _____
B.3. _____
B.4. _____

VII. Turnkey Power Plant Including Site

A. Combined Cycle Combustion Turbine

A.1. Same as Section IV. _____

A.2. Same as Section V.A. _____

B. Simple Cycle Combustion Turbine

B.1. Same as Section IV. _____

B.2. Same as Section V.B. _____

## APPENDIX A

### WUTC BIDDING RULE

Bidders participating in Avista's 2000 RFP that would like a copy of the WUTC bidding rule WAC 480-107 can receive a copy by contacting Doug Young at (509) 495-4521 at Avista's general office in Spokane, Washington.

# APPENDIX B

## MODEL CONTRACTS

The following 1994 model contracts are included in this appendix

1. DEMAND SIDE MANAGEMENT PURCHASE AGREEMENT
2. FIRM POWER PURCHASE AGREEMENT
3. PARALLEL OPERATING AND POWER PURCHASE AND SALE AGREEMENT

These model contracts provide a basis for negotiation of a purchase agreement with Avista Corporation. Bidders should expect that a final agreement will have many changes in terms and conditions through the negotiation process.

Bidders participating in Avista's 2000 RFP that would like a copy of these model contracts can receive a copy by contacting Doug Young at (509) 495-4521 at Avista's general office in Spokane, Washington.

## APPENDIX C

RETAIL TARIFFS

Bidders participating in Avista's 2000 RFP that would like a copy of Avista's retail service tariffs can receive a copy by contacting Doug Young at (509) 495-4521 at Avista's general office in Spokane, Washington.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-7)

# RFP Bid Analysis Review

AVISTA
Corp.

Avista Corporation
Spokane, Washington

December 2000

R·W·BECK

December 7, 2000

R·W·BECK

Mr. Robert J. Lafferty
Manager, Electric Resources
Avista Corporation
1411 East Mission, MSC-7
Spokane, Washington 99220-3727

Dear Mr. Lafferty:

Subject: **Review of Avista Corporation's RFP Bid Analysis**

R. W. Beck, Inc., was retained by Avista Corporation (Avista) in October 2000 to conduct an independent review of the methodology and assumptions used by Avista to review the bids received from its August 2000 Request for Proposals titled "Evaluation of Resources from Electric Energy Efficiency and/or Power Supply Resources." The goal of R. W. Beck's independent review was to assure that the economic analysis of the alternative resource bids was conducted in a fair, reasonable, and appropriate manner. Avista's analysis of certain other factors (such as transmission accessibility, environmental factors, etc.) was not reviewed. This report summarizes our review of Avista's analysis conducted through November 28, 2000. Changed conditions occurring after such date were not considered in our review.

## BACKGROUND

Avista Utilities, a division of Avista Corporation, is a private investor-owned electric utility with headquarters in Spokane, Washington. In August 2000, Avista issued a Request for Proposals (RFP) seeking potential resources to meet its system requirements of energy and capacity. According to the RFP:

> *"... The company has identified a power need of approximately 300 MW of both capacity and corresponding energy. Resource availability in the year 2004 would fit Avista's requirements best.*
>
> *"... The goal of the 2000 RFP will be to identify low cost and environmentally sound resource options that best satisfy Avista's resource needs."*

In response to the RFP, Avista received numerous proposals from resource sponsors (the bids). As part of the bid review process, Avista attempted to calculate the economic and financial benefit of each of the bids using Avista-developed methodology and assumptions. Avista also studied the potential benefits and costs of enhancing an existing generation facility, which we will refer to as the "self-build option" in this report.

To assure the fairness and reasonabless of their economic analysis, Avista retained R. W. Beck to conduct an independent review of their methodology and assumptions; to assure that significant economic risks, benefits, and costs were identified; and to make note of, and suggest corrections for, any deficiencies found. R. W. Beck has completed an independent review of the economic analysis of the bids and our findings and conclusions are presented in this report.

## SCOPE OF SERVICES

Avista identified the following tasks as part of the scope of services for a third-party review of Avista's evaluation methodology and input assumptions.

1. Review the *Prosym™* dispatch model inputs and assumptions on six to eight representative bids. Make recommendations for any modifications aimed at achieving Avista's RFP goals.
2. Review the Avista economic model inputs and assumptions on six to eight representative bids. Make recommendations for any modifications aimed at achieving Avista's RFP goals.
3. Be available to discuss with Avista representatives the recommended modifications under Tasks 1 and 2 above.
4. Prepare a final letter report summarizing recommended modifications for dispatch model and economic model inputs and assumptions aimed at achieving Avista's RFP goals.
5. Present a review of the recommendations for analysis inputs and assumptions to Avista management, staff, and commission staff from Washington and Idaho in Spokane, Washington.

This letter report constitutes completion of Task 4 above. The Task 5 presentation was provided on November 29, 2000 at Avista's headquarters building in Spokane.

## INFORMATION PROVIDED AND REVIEWED

Avista provided several reports, analyses, and other information for use in the independent review. In addition, numerous group discussions were held with Avista staff for clarification and further insight. The information reviewed is summarized as follows:

1. August 2000 RFP from Avista.
2. "Evaluation Guidance for Electric RFP Bid Proposals" from Avista.
3. "WSCC Regional Electricity Market Price Forecast 2001-2012, September 2000" prepared by Henwood Energy Services, Inc., for Avista.

4. Submitted proposals from six bidding resource sponsors, including:
   a. Calpine Corporation
   b. Enron North America Corporation
   c. Newport Northwest, LLC
   d. Pacific Winds Inc.
   e. Regional Power Inc.
   f. Williams Energy Marketing & Trading Company
5. *Prosym*™ model input files representing the Avista system for each of seven proposed resource options and the enhancement of the existing Rathdrum generation facility (self-build option). The eight various resource bids/options given to R. W. Beck for review were identified by Avista as follows:
   a. Calpine
   b. Enron Monthly Toll
   c. Newport Northwest
   d. Pacific Winds
   e. Rathdrum
   f. Regional Power
   g. Williams Energy Flat Purchase
   h. Williams Energy Toll
6. *Prosym*™ model results contained in electronic spreadsheets for each of the eight resource options.
7. Economic analysis spreadsheets for each of the eight resource options, used to calculate each resource option's projected revenues, costs, and net project benefit to the Avista system.

## OVERVIEW OF AVISTA'S APPROACH, METHODOLOGY, AND ASSUMPTIONS

Avista used the production costing and market simulation model, *Prosym*™, to determine certain costs and benefits of each of the bids as well as the self-build option. *Prosym*™ is generally considered within the electricity industry to be an acceptable model for such purposes, capable of modeling both expansive, interconnected markets and smaller utility systems in detail and with a high degree of accuracy. Avista staff created a detailed model of Avista's system, representing on-peak and off-peak loads, hydroelectric and thermal generating resources, contractual sales and purchases, and spot-market sales and purchases.

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The spot-market sales and purchase prices used in the model were based on market price forecasts provided by R. W. Beck staff. A price forecast was provided for a base case scenario and various sensitivity scenarios, developed primarily to provide a range of prices and to illustrate the change in market prices resulting from a change in key input assumptions, such as a change in natural gas prices. A detailed discussion of the market prices used in the analysis is provided below under the heading "Market Price Forecast."

For each pricing scenario (base case and sensitivities) the model was run once based on existing resources, and then a second time with each resource proposal individually added to the model. The difference in Avista's total system cost between the various model simulations was used to determine which projects are most beneficial or most costly. Because the results from model simulations are fundamental to Avista's economic decisions, the accuracy and completeness of input variables is very important.

Avista's economic analysis of the bids and the self-build option was primarily presented in the form of a spreadsheet model that compared Avista's total system cost with and without each of the resource options and the potential cost and revenue requirements of each of the proposed resource alternatives. These economic analysis spreadsheets provided detailed data for each of the resource options for the total Avista system for years 2001 to 2025. Included in the economic analysis spreadsheets are:

- Financial assumptions

  Sample of Avista's most critical assumptions:

| | |
|---|---|
| State Income Tax Rate | 0.00% (None) |
| Federal Income Tax Rate | 35.00% |
| Discount Factor | 7.77% |
| Tax Life (years) | 20 |
| Book Life (years) | 20 |
| Property Tax Rate | 1.4099% |
| Levelize Period (years) | 20 |

  Cost of Capital:

| Capital Source | Percent of Total | Percent Rate | Weighted Average | After-tax Weighted Average |
|---|---|---|---|---|
| Debt | 49.00% | 7.36% | 3.61% | 2.35% |
| Preferred Stock | 9.00% | 8.11% | 0.73% | 0.73% |
| Common Stock | 42.00% | 11.16% | 4.69% | 4.69% |
| | 100.00% | | 9.03% | 7.77% |

- Projections of annual energy produced from the various resource options to supply Avista's system, calculated through the *Prosym*™ simulation model where applicable.

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- Projected resource costs—including any applicable fuel costs, fuel transportation costs, variable operations and maintenance costs (variable O&M), transmission costs, and fixed costs. These costs, if not explicitly set forth as an exact amount in the bids, are projected using the *Prosym*™ simulation model, where appropriate.
- Projected operating margin—defined by Avista as the added benefit or cost savings to the total system cost when the resource is included as compared with the Avista base case (the case where no resource options are included and all required energy is purchased from the market at projected market prices). The projected operating margin is calculated using the *Prosym*™ simulation model.
- Projected net project benefit—calculated by subtracting fixed and outside variable costs, not included in the *Prosym*™ simulation model, from the projected operating margin.

## MARKET PRICE FORECAST

Initially, Avista staff used a market price forecast supplied by Henwood Energy Services, Inc. (HESI) to represent market prices in the *Prosym*™ model. This forecast supplied reasonable monthly on-peak and off-peak market prices for the Pacific Northwest market area. However, the HESI forecast did not provide disaggregated hourly prices and the accompanying report did not provide a detailed description of the assumptions and conditions used in their analysis. As a result, the Avista analysis initially contained 24 market prices per year, an on-peak price and an off-peak price for each month. HESI also provided Avista with a copy of its monthly gas price forecast which it used in developing the market price projections.

After the initial review of Avista's bid analysis, it was determined that the market price forecast needed a higher level of detail in order to improve confidence in the results. The R. W. Beck team suggested several recommendations related to market price projections including, (i) use of an hourly prices and hourly dispatch, (ii) use of monthly gas prices instead of annual average prices, and (iii) forecasting of both energy and capacity prices instead of forecasting all-in prices. R. W. Beck also recommended the use of an additional set of sensitivities in order to create a wider band of market prices to be used in the bid evaluations.

Through discussions with Avista staff, it was decided that a new market price forecast supplied by the R. W. Beck Market Pricing Group would be used in a revised bid analysis. This market price forecast supplied an increased level of detail for the bid review process and also provided Avista staff with an understanding of all the key input assumptions used in the forecast of the long-term prices. Three additional sensitivity price forecasts were created: one using 25 percent higher natural gas prices, one using 25 percent lower natural gas prices, and one with an increase in load by 1.5 percent.

## R. W. BECK'S REVIEW OF THE AVISTA ANALYSIS

R. W. Beck's independent review of Avista's economic analysis of the bids and the self-build option focused on the methodology and key assumptions used in the analysis. The R. W. Beck review team carefully reviewed all of the necessary documents, including the August 2000 RFP, the HESI Market Price Forecast, the model input files, and the initial economic analysis spreadsheets. Numerous conversations between Avista staff and the R. W. Beck review team took place, discussing issues such as model input variables, spreadsheet calculations, the market price forecast, and the meaning of certain terms used in Avista's analysis. The following two subsections summarize our comments on Avista's methodology and the key assumptions used in the analysis.

### AVISTA'S ANALYTICAL APPROACH AND METHODOLOGY

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 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 spreadsheet analyses.

### REVIEW OF KEY ASSUMPTIONS USED IN THE AVISTA ANALYSIS

The following comments focus on a number of the key input assumptions used by Avista in its analysis:

- Market Prices: The annual average market prices used in the initial analysis were within a reasonable range based on recent economic trends and market data. Overall price levels for the Pacific Northwest market were not unreasonable. The use of projected hourly prices in the dispatching analysis allowed for a potentially more fair evaluation of each bid resource and technology type.
- Fuel Prices: We believe the price of gas forecast used was reasonable and based on reputable sources. Monthly price variations follow an expected pattern. Fuel price projections were used appropriately in the model input files.

- Avista's Resources and Loads: Avista's existing resources and loads were modeled in a reasonable manner based on the data that was provided for review. Operating characteristics of the individual generating units, purchases, and sales were modeled with a reasonable level of accuracy.
- Bids and Self-Build Option: Based on the information contained in each reviewed proposal and information provided on the self-build option, Avista modeled the operational characteristics and costs of each of the resources bid and the self-build option fairly and without bias.
- Inflation, Cost of Capital, and Other Financial Assumptions: Financial and economic parameters used in the evaluation were reasonable and based on recent economic trends.
- Sensitivity Cases: The gas prices used to create the high fuel price and low fuel price sensitivity cases provide for a reasonable range of prices around the base case. Historical market prices for natural gas show a 20 to 25 percent range of volatility. The gas prices used in the sensitivity cases were 25 percent higher and 25 percent lower than the base case scenario, which used market prices.

  The high load sensitivity gives a good indication of how increases in load affect market prices. Although the load sensitivity case, which entails an annual average compounded rate of 1.5 percent increase in loads for all WSCC market areas, does not capture the short-duration load spikes, the sensitivity does provide a reasonable increase in market prices for yearly, weekly, and hourly prices. Short-duration load spikes, such as those occurring during only a few hours each year are captured well in the capacity portion of the market pricing forecast.

## CONSIDERATIONS AND ASSUMPTIONS

In the preparation of this letter report and the conclusions that follow, we have made certain assumptions with respect to conditions, which may occur in the future. In addition, we have used and relied upon certain information and assumptions provided to us by sources which we believe to be reliable. We believe the use of such information and assumptions is reasonable for the purposes of this report. However, some assumptions will invariably not materialize as stated herein or may vary significantly due to unanticipated events and circumstances. Therefore, actual results can be expected to vary from those projected to the extent that actual future conditions differ from those assumed by us or provided to us by others.

This independent review included consideration of materials and analyses provided to us by Avista staff. Avista indicated that a representative sample of the various types of bids was provided for our review. Therefore, we did not review all of the bids submitted to

Avista by resource sponsors and we are unaware of those other proposals that Avista may have received, in terms of resource capacity, cost, location, and technology type. R. W. Beck accepted Avista's assumptions, without review, regarding the accessibility of Avista's transmission system for each of the proposed resource options. We did not conduct an independent review of Avista's system import and export capability or Avista's assumptions regarding its ability to purchase from and sell into the regional electricity market.

R. W. Beck was retained to conduct an independent review of the economic analysis of the bids and the self-build option. According to Avista staff, in addition to the economic analysis, other non-economic and non-financial factors will also be used to determine the merit of the submitted bids (including items such as credit-worthiness of resource sponsors, environmental factors, etc.). Avista's economic analysis will comprise only a portion of the evaluation process used to judge each of the bids and the self-build option. R. W. Beck did not review any of these non-economic factors nor the final process for determining the winning resource option.

## CONCLUSIONS

Based on the review summarized in this letter report and the considerations and assumptions set forth above, R. W. Beck concludes that:

- 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.

R·W·BECK

We appreciate the opportunity to be of service to Avista Corporation in its evaluation of its future resource options, and we hope to have the opportunity to work with you again in the near future.

Sincerely,

R. W. BECK, INC.

Richard Cuthbert

Richard W. Cuthbert
Project Manager

Angelo Muzzin

Angelo Muzzin
Client Services Director
Pacific Northwest

RWC:bb

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-C8)

CONFIDENTIAL CORRESPONDENCE

AVISTA® Corporation

*Energy Resources Memorandum*

Date: December 6, 2000

To: Rick Sterling, IPUC
Hank McIntosh, WUTC

From: Bob Lafferty RJL

Subject: Final RFP Economic Matrixes

### *Introduction and Summary*

On November 29th Avista Corporation (Avista) distributed copies of its draft 3rd screening evaluation economics matrixes. Attached are updated matrixes detailing modest changes to the economic figures associated with the four Rathdrum upgrade scenarios. The changes did not affect the ultimate ranking of the resource projects. A set of new tables and graphics follow and replace those handouts presented at the meeting. Please update your files with these revisions.

### *Discussion*

Three modifications to the Rathdrum upgrade were made to reflect Avista's present understanding of project costs: 1) additional capital expenditures of approximately $8.7 million for labor, a modified wastewater disposal system, and silencers for the LM-6000 units; 2) the addition of sales tax on all non-labor costs in Idaho; and 3) an adjustment to the net generation values used to calculate per-MWh savings value. Additionally, an adjustment to the economics of the Coyote Springs 2 was made to reflect that the capital asset would be treated as operational beginning in July 2002 instead of January 2002.

Additional capital expenditures were identified that increased Rathdrum upgrade costs by $8.7 million. The additional cost includes a $3.5 million adjustment to labor. In the earlier analyses, non-prevailing wage labor rates were used. This new value assumes prevailing-wage labor.

Due to potential concerns over wastewater disposal issues, the new cost figure includes a $4.2 million zero-discharge system (the Cogentrix project uses such a system). Finally, $1.0 million was added to install silencer equipment on the LM-6000s units to address noise issues that are of concern to project neighbors.

In addition to increased capital costs, five-percent sales tax was added for all non-labor construction costs in Idaho. Although sales tax was applied for all construction in Washington State, an oversight prevented the application of sales tax in Idaho. The total impact of the Idaho sales taxes varied between scenarios, ranging between $8-10 million.

Finally it was discovered that projected savings of the Rathdrum upgrade, on a per-MWh basis, was understated. This additional oversight had project savings based on total generation. Only the *net* generation value should have been used. In other words, the correct generation quantity in the Rathdrum upgrade should have the expected generation under existing conditions netted against total project generation.

The ultimate impact of these changes to the Rathdrum upgrade and Coyote Springs 2 project did not significantly affect either the economic or multi-attribute ranking of the short list. Please feel free to give Clint Kalich at 509.495.4532, or me, a call if you would like to discuss the results presented in this memorandum further.

**Attachments (5):**

- **Table 1**
- **Table 2**
- **Table 3**
- **Exhibit 4**
- **Exhibit 5**

**CONFIDENTIAL**

AVISTA CORP.
2000 Request-for-Proposals
Weighted Matrix Evaluation

## Third Round Screening

12-01-2000

NE = "Not Evaluated"

| No. | Bid/Project | Short List | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors | Weighted Total |
|---|---|---|---|---|---|---|---|---|---|
| | | | Financial/Price Factors | | | Electric Power & Social/Environmental Factors | | | Total |
| | Weighting Factor | | 35% | 15% | 15% | 5% | 20% | 10% | 100% |
| | Ranking | 1 - 10 | | | | | | | |
| | *Short List Sorted by Ranking* | | | | | | | | |
| 25 | CS2 CCCT | x | 10 | 10 | 5 | 5 | 9 | 5 | 8.3 |
| 24b | RCT Upgrades w/ 2 LM at RCT and 2 at NE | x | 10 | 10 | 5 | 4 | 10 | 3 | 8.25 |
| 24a | RCT Upgrades w/ 4 LM6000 | x | 10 | 10 | 5 | 5 | 10 | 2 | 8.2 |
| 14 | PG&E Bid #1 10 Year Flat Purchase | x | 9 | 9 | 10 | 10 | 4 | 5 | 7.8 |
| 5 | Enron Bid #1 20 Year Flat | x | 8 | 10 | 10 | 10 | 4 | 5 | 7.6 |
| 21 | Williams Bid #1 20 Year Flat Purchase | x | 8 | 10 | 10 | 10 | 4 | 5 | 7.6 |
| 10 | Enron #6 Turnkey | x | 7 | 10 | 5 | 3 | 8 | 4 | 6.85 |

*Note: Newport Northwest and Regional Power were dropped from the short list due to significant deficiencies*

Economic Benefit

| Base Case Range | Rating |
|---|---|
| >1 | 10 |
| 0 - 1 | 9 |
| (1) - 0 | 8 |
| <(1) | 7 |

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Dec. 1, 00

Avista Corp
2000 RFP
Weighted Matrix Documentation

# 3rd Round Screening
## RFP Bid Evaluation Matrix Documentation

Decemb. , 2000

| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 25 | CS2 CCCT (Avista project at cost) | Rating=10<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This project is in the 1st tier of nominal levelized savings: NLC>$1.00/MWh Design specification is completed and major equipment is on order. Permits are in place. Therefore, costs are well defined on this project. Project is on long-term leased property. | Rating=10<br>Top rating | Rating=5<br>Price reflects potential volatility of natural gas price changes over time. Natural gas price can be fixed for periods up to ten years at market prices that could provide the same stability benefits as a fixed price electric bid for all or a portion of a natural gas turbine's fuel requirements. This could raise a turbine's rating in this category. | Rating=5<br>Gas line is in place with adequate capacity. Transportation available at market rates from third parties. | Rating=9<br>Unit owned. Highly dispatchable. On BPA transmission - BPA indicates that constraints are unlikely moving power to Avista system. Path request has not yet been made. | Rating=5<br>Permitted turbines received a five rating. Community is supportive. Water supply is in place from the existing Coyote Springs I project. Water disposal is in place with the Port. |

# 3rd Round Screening
## RFP Bid Evaluation Matrix Documentation

| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 24b | RCT Upgrades + 2 LM6000's at Rathdrum and 2 LM6000's at NE (Avista project - at cost) | Rating=10<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This project is in the 1st tier of nominal levelized savings: NLC>$1.00/MWh | Rating=10<br>Top rating. | Rating=5<br>Price reflects potential volatility of natural gas price changes over time. Natural gas price can be fixed for periods up to ten years at market prices that could provide the same stability benefits as a fixed price electric bid for all or a portion of a natural gas turbine's fuel requirements. This could raise a turbine's rating in this category. | Rating=4<br>Pipeline pressure needs to be increased at the NE site. A booster station has been added to the project costs. Pipeline capacity and pressure is adequate to the Rathdrum site. Transportation available at market rates from third parties. | Rating=10<br>Units owned. Highly dispatchable. Integrated on Avista transmission. Less exposure to transmission isolation from load due to transmission outages. Located within Avista control area. No BPA transmission costs or dynamic scheduling issues. Located near load. 4 SSCTs provide higher dispatch and maintenance flexibility compared to current project configuration. | Rating=3<br>Permit in place but requires a modification on a non-PSD basis (17 months). Neighbors are concerned with noise and aesthetic issues associated with further development of the existing project. Water source would be from the city of Rathdrum, a well adjacent to the site or from wells across the road. If an onsite well is used or if another well is drilled, then additional water rights will be needed. Water disposal option: The city of Rathdrum has a 12" sewer line running down the road in front of the project. |

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# 3rd Round Screening
# RFP Bid Evaluation Matrix Documentation



| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 24a | RCT Upgrade + 4 LM6000's at Rathdrum (Avista project at cost) | Rating=10<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This project is in the 1st tier of nominal levelized savings: NLC>$1.00/MWh | Rating=10<br>Top rating. | Rating=5<br>Price reflects potential volatility of natural gas price changes over time. Natural gas price can be fixed for periods up to ten years at market prices that could provide the same stability benefits as a fixed price electric bid for all or a portion of a natural gas turbine's fuel requirements. This could raise a turbine's rating in this category. | Rating=5<br>Pipeline capacity and pressure is adequate to the site. Transportation available at market rates from third parties. | Rating=10<br>Units owned. Highly dispatchable. Integrated on Avista transmission. Less exposure to transmission isolation from load due to transmission outages. Located within Avista control area. No BPA transmission costs or dynamic scheduling issues. Located near load. 4 SSCTs provide higher dispatch and maintenance flexibility compared to current project configuration. | Rating=2<br>Would require a PSD permit process (25 months vs 17 months). Neighbors are concerned with noise and aesthetic issues associated with further development of the existing project. Water source would be from the city of Rathdrum, a well adjacent to the site or from wells across the road. If an onsite well is used or if another well is drilled, then additional water rights will be needed. Water disposal option: The city of Rathdrum has a 12" sewer line running down the road in front of the project. |

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## 3rd Round Screening
## RFP Bid Evaluation Matrix Documentation



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| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 14 | PG&E Bid #1 Flat Purchase | Rating=9<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 2nd tier of nominal levelized savings: NLC=$0MWh to $1.00/MWh | Rating=9<br>Avista's credit assessment rates this somewhat below the top. The basis is the financial pressure high power prices have placed on the company in California. PG&E has had to increase debt financing by 25%. Debt service coverage is now a larger obligation. | Rating=10<br>Fixed price; no fuel risk. | Rating=10<br>No fuel transportation risk. | Rating=4<br>Market purchase. No dispatchability. BPA transmission assumed from Mid-C delivery point to Avista System - unconstrained path. | Rating=5<br>Assigned all market power bids a turbine rating of five. If it is a blended product, we are assuming that the resources are equivalent to a turbine. |
| 5 | Enron Bid #1 20 Year Flat | Rating=8<br>Enron raised their price to $47.25/MWh for 300MW. Williams had a better initial bid price of $42.25/MWh. Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 3rd tier of nominal levelized savings: NLC=(1.0) to $0.0/MWh. | Rating=10<br>Top rating. | Rating=10<br>Fixed price; no fuel risk. | Rating=10<br>No fuel transportation risk. Not tied to a specific plant. | Rating=4<br>Market purchase. No dispatchability. BPA transmission assumed - unconstrained path. | Rating=5<br>Assigned all market power bids a turbine rating of five. If it is a blended product, we are assuming that the resources are equivalent to a turbine. |

# 3rd Rounu Screening
# RFP Bid Evaluation Matrix Documentation



| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 21 | Williams Bid #1 Flat Purchase | Rating=8<br>Williams raised their price to $47.85/MWh; a $5.60 increase. Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 3rd tier of nominal levelized savings: NLC=(1.0) to $0.0/MWh. | Rating=10<br>Top rating | Rating=10<br>Fixed price; no fuel risk. | Rating=10<br>No fuel transportation risk. | Rating=4<br>Market sale. Flat; no dispatchability. BPA transmission assumed - unconstrained path. | Rating=5<br>Assigned all market power bids a turbine rating of five. If it is a blended product, we are assuming that the resources are equivalent to a turbine. |

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# 3rd Round Screening
## RFP Bid Evaluation Matrix Documentation





| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 10 | Enron #6 Turnkey | Rating=7<br>Ranking based on relative Nominal Levelized Cost (NLC) groupings among top economic bids. This bid is in the 4th tier of nominal levelized savings: NLC<(1.0)/MWh. Property is on a long-term lease from the Port. | Rating=10<br>Top credit rating. | Rating=5<br>Price reflects potential volatility of natural gas price changes over time. Natural gas price can be fixed for periods up to ten years at market prices that could provide the same stability benefits as a fixed price electric bid for all or a portion of a natural gas turbine's fuel requirements. This could raise a turbine's rating in this category. | Rating=3<br>Cascade Natural Gas will be the supplier. A one mile lateral will need to be constructed. We would add a gas scrubber, heater and odorizer (approx. $500,000) 400psi is available. 475psi is needed and therefore a booster station is needed. (We added $5 million in additional costs). | Rating=8<br>This is a Longview port district site. We would own the plant. Highly dispatchable. BPA transmission required. The straight-forward interconnection costs have been estimated and are included in the economic model. However, overall costs will not be know until BPA completes their impact study in Feb 2001. Transmission path constraints are also not known at this time. No request has been made to study a path to the Avista system. Two proposed projects are ahead of Enron in the BPA que that are north of this project. | Rating=4<br>Permitting process is underway. Notice of Construction was applied for in mid-October. It will be non-PSD and will not require EFSEC review since it is below 250 MW. It is located in an industrial area. No complex terrain issues. Project plan is to receive 50% of water supply from the city and 50% from the port. 1200gpm is the expected requirement, but this could increase. A couple of options exist for water disposal. Enron has met with DEQ to find out if water can be discharged into an adjacent log pond. Another alternative would be if the city of Longview were to expand their sewage disposal system. |

# 3rd Round Screening
## RFP Bid Evaluation Matrix Documentation

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| # | Bid/Project | Economic Benefit | Financial Performance Capability | Fuel Price Risk | Fuel Availability Risk | Electric Factors | Environmental Factors |
|---|---|---|---|---|---|---|---|
| | *Weighting Factor* | *35%* | *15%* | *15%* | *5%* | *20%* | *10%* |
| 18 | Regional Power Bid | Rating=NE<br>Not further evaluated due to lack of firm transmission from Canada. | Rating=5<br>Average rating. Need further investigation. | Rating=10<br>No fuel price risk. | Rating=7<br>Critical water year is 85% of normal on average. Some months are 70% of normal. This project requires 7 MW of back-up capacity firming. No actual water basin studies were provided; just representative basin studies. | Rating=0<br>Firm transmission was not obtainable. Therefore, this project is dropped from further evaluation. Not dispatchable. Remote transmission with single contingency exposure. | Rating=7<br>Consistent with national legislative initiatives, small hydro is ranked above gas turbine projects. No fish issues are affecting this project. However, permitting is not finalized (1 pt deduct) |
| 11 | Newport NW Tolling | Rating=NE<br>Not further evaluated due to lack adequate financial backing at this time. | Rating=1<br>Lack of a proven track record. Lack of available current financial information. Lack of any credit rating at this time. Lack of adequate financial backing at this time caused this project to be removed from further evaluation. | Rating=5<br>Price reflect potential volatility of natural gas. | Rating=3<br>Requires a major expansion of either NW Pipeline or PGT. | Rating=6<br>A unit contingent tolling bid. Daily dispatchability. Variable heat rate tied to output level. Single transmission contingency exposure. | Rating=3<br>Turbine project would normally get a 5 rating. However, this project rating reduced due to significant permitting hurdles. Need additional water rights and emission credits. |

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# Coyote Springs 2

## Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Installed Cost | 187,867 | $000s | Fixed Charge | 0.00 | per kW-month | | | |
| Project Capacity | 280.0 | MW | Fixed O&M | 1.75 | 2002$ per kW-month | | | |
| Heat Rate | 7,090 | Btu/kWh | Escalation Rates | | | Insurance Cost | 563.6 | 0.3% of installed cost ($000s) |
| Gas Usage Rate | 47.6 | 000s dth/day | Fixed O&M | 2.6 | percent | Gas Transport | 0.38760 | 2001 $/dth/day |
| | | | Variable O&M | 2.6 | percent | Electric Wheeling | 1,243 | $/MW-month thru 2006 |
| | | | Transportation | 2.0 | percent | General Inflation | 2.6 | percent |

| | | |
|---|---|---|
| Nominal Discount Rate | 7.8 | percent |
| Real Discount Rate | 5.0 | percent |

**Fixed Costs**

| Row | | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 19 | 2 | 2002 | 1,037.8 | 16,632 | 0 | 16,632 | 16.0 | 2,948 | 3,438 | 2,088 | 1,302 | 289 | 10,065 | 9.7 |
| 20 | 3 | 2003 | 1,997.2 | 32,135 | 0 | 32,135 | 16.1 | 6,050 | 7,013 | 4,176 | 2,516 | 593 | 20,348 | 10.2 |
| 21 | 4 | 2004 | 2,020.7 | 30,906 | 0 | 30,906 | 15.3 | 6,207 | 7,153 | 4,176 | 2,428 | 609 | 20,573 | 10.2 |
| 22 | 5 | 2005 | 2,030.7 | 29,816 | 0 | 29,816 | 14.7 | 6,368 | 7,296 | 4,176 | 2,340 | 625 | 20,805 | 10.2 |
| 23 | 6 | 2006 | 2,025.2 | 28,950 | 0 | 28,950 | 14.3 | 6,534 | 7,442 | 4,176 | 2,251 | 641 | 21,044 | 10.4 |
| 24 | 7 | 2007 | 2,031.7 | 28,127 | 0 | 28,127 | 13.8 | 6,704 | 7,591 | 4,260 | 2,163 | 657 | 21,375 | 10.5 |
| 25 | 8 | 2008 | 2,038.8 | 27,317 | 0 | 27,317 | 13.4 | 6,878 | 7,742 | 4,345 | 2,075 | 675 | 21,715 | 10.7 |
| 26 | 9 | 2009 | 2,037.1 | 26,510 | 0 | 26,510 | 13.0 | 7,057 | 7,897 | 4,432 | 1,987 | 692 | 22,065 | 10.8 |
| 27 | 10 | 2010 | 2,037.4 | 25,729 | 0 | 25,729 | 12.6 | 7,240 | 8,055 | 4,521 | 1,898 | 710 | 22,425 | 11.0 |
| 28 | 11 | 2011 | 2,035.9 | 24,956 | 0 | 24,956 | 12.3 | 7,429 | 8,216 | 4,611 | 1,810 | 729 | 22,795 | 11.2 |
| 29 | 12 | 2012 | 2,044.0 | 24,202 | 0 | 24,202 | 11.8 | 7,622 | 8,381 | 4,703 | 1,722 | 747 | 23,175 | 11.3 |
| 30 | 13 | 2013 | 2,040.2 | 23,437 | 0 | 23,437 | 11.5 | 7,820 | 8,548 | 4,797 | 1,633 | 767 | 23,566 | 11.6 |
| 31 | 14 | 2014 | 2,038.1 | 22,687 | 0 | 22,687 | 11.1 | 8,023 | 8,719 | 4,893 | 1,545 | 787 | 23,968 | 11.8 |
| 32 | 15 | 2015 | 2,034.4 | 21,951 | 0 | 21,951 | 10.8 | 8,232 | 8,894 | 4,991 | 1,457 | 807 | 24,381 | 12.0 |
| 33 | 16 | 2016 | 2,038.9 | 21,224 | 0 | 21,224 | 10.4 | 8,446 | 9,072 | 5,091 | 1,369 | 828 | 24,805 | 12.2 |
| 34 | 17 | 2017 | 2,023.4 | 20,467 | 0 | 20,467 | 10.1 | 8,666 | 9,253 | 5,193 | 1,280 | 850 | 25,242 | 12.5 |
| 35 | 18 | 2018 | 2,022.9 | 19,723 | 0 | 19,723 | 9.7 | 8,891 | 9,438 | 5,297 | 1,192 | 872 | 25,690 | 12.7 |
| 36 | 19 | 2019 | 2,022.1 | 18,985 | 0 | 18,985 | 9.4 | 9,122 | 9,627 | 5,403 | 1,104 | 895 | 26,150 | 12.9 |
| 37 | 20 | 2020 | 2,024.5 | 18,269 | 0 | 18,269 | 9.0 | 9,359 | 9,819 | 5,511 | 1,015 | 918 | 26,623 | 13.2 |
| 38 | 21 | 2021 | 2,021.2 | 17,555 | 0 | 17,555 | 8.7 | 9,603 | 10,016 | 5,621 | 927 | 942 | 27,108 | 13.4 |
| 39 | 22 | 2022 | 2,015.5 | 16,928 | 0 | 16,928 | 8.4 | 9,852 | 10,216 | 5,733 | 839 | 966 | 27,607 | 13.7 |
| 40 | 23 | 2023 | 2,016.3 | 16,505 | 0 | 16,505 | 8.2 | 10,108 | 10,420 | 5,848 | 750 | 991 | 28,119 | 13.9 |
| 41 | 24 | 2024 | 2,017.4 | 15,928 | 0 | 15,928 | 7.9 | 5,186 | 10,629 | 5,965 | 662 | 1,017 | 23,459 | 11.6 |
| 42 | 25 | 2025 | 2,007.5 | 15,591 | 0 | 15,591 | 7.8 | 5,320 | 11,058 | 6,084 | 574 | 1,044 | 24,080 | 12.0 |
| 43 | | | | | | | | | | | | | | |
| 44 | 2001$ | | | | | | | | | | | | | |
| 45 | Net Present Value | | | 244,889 | 0 | 244,889 | | 69,086 | 78,119 | 44,329 | 17,703 | 6,940 | 216,177 | |
| 46 | Nominal Levelized Cost ($/MWh) | | | | | | 11.8 | | | | | | | 10.4 |
| 47 | Real Levelized Cost ($/MWh) | | | | | | 9.2 | | | | | | | 8.1 |

| Row | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 19 | 26,697 | 26,697 | 25.7 | 33,164 | 6,467 | 6.2 | 24,313 | 456 | 24,769 | 23.9 | 51,466 | 49.6 |
| 20 | 52,484 | 52,484 | 26.3 | 40,552 | (11,932) | (6.0) | 42,346 | 904 | 43,250 | 21.7 | 95,734 | 47.9 |
| 21 | 51,479 | 51,479 | 25.5 | 43,414 | (8,064) | (4.0) | 39,090 | 936 | 40,026 | 19.8 | 91,505 | 45.3 |
| 22 | 50,621 | 50,621 | 24.9 | 43,706 | (6,913) | (3.4) | 37,848 | 965 | 38,813 | 19.1 | 89,434 | 44.0 |
| 23 | 49,994 | 49,994 | 24.7 | 46,225 | (3,770) | (1.9) | 40,460 | 988 | 41,448 | 20.5 | 91,442 | 45.2 |
| 24 | 49,502 | 49,502 | 24.4 | 48,010 | (1,492) | (0.7) | 43,102 | 1,017 | 44,119 | 21.7 | 93,621 | 46.1 |
| 25 | 49,032 | 49,032 | 24.0 | 49,547 | 515 | 0.3 | 45,295 | 1,048 | 46,343 | 22.7 | 95,375 | 46.8 |
| 26 | 48,575 | 48,575 | 23.8 | 50,626 | 2,051 | 1.0 | 46,894 | 1,074 | 47,968 | 23.5 | 96,543 | 47.4 |
| 27 | 48,154 | 48,154 | 23.6 | 53,003 | 4,849 | 2.4 | 48,653 | 1,103 | 49,756 | 24.4 | 97,911 | 48.1 |
| 28 | 47,750 | 47,750 | 23.5 | 53,853 | 6,103 | 3.0 | 50,500 | 1,131 | 51,631 | 25.4 | 99,382 | 48.8 |
| 29 | 47,377 | 47,377 | 23.2 | 59,849 | 12,472 | 6.1 | 52,748 | 1,165 | 53,913 | 26.4 | 101,290 | 49.6 |
| 30 | 47,003 | 47,003 | 23.0 | 53,840 | 6,838 | 3.4 | 54,747 | 1,192 | 55,939 | 27.4 | 102,941 | 50.5 |
| 31 | 46,655 | 46,655 | 22.9 | 54,962 | 8,308 | 4.1 | 57,051 | 1,223 | 58,274 | 28.6 | 104,929 | 51.5 |
| 32 | 46,332 | 46,332 | 22.8 | 54,623 | 8,291 | 4.1 | 59,640 | 1,253 | 60,893 | 29.9 | 107,225 | 52.7 |
| 33 | 46,030 | 46,030 | 22.6 | 54,554 | 8,525 | 4.2 | 62,412 | 1,290 | 63,702 | 31.2 | 109,732 | 53.8 |
| 34 | 45,708 | 45,708 | 22.6 | 54,448 | 8,740 | 4.3 | 64,527 | 1,315 | 65,842 | 32.5 | 111,550 | 55.1 |
| 35 | 45,412 | 45,412 | 22.4 | 54,817 | 9,404 | 4.6 | 66,913 | 1,349 | 68,262 | 33.7 | 113,674 | 56.2 |
| 36 | 45,135 | 45,135 | 22.3 | 54,979 | 9,845 | 4.9 | 69,405 | 1,386 | 70,791 | 35.0 | 115,926 | 57.3 |
| 37 | 44,891 | 44,891 | 22.2 | 62,998 | 18,106 | 8.9 | 72,342 | 1,425 | 73,767 | 36.4 | 118,659 | 58.6 |
| 38 | 44,663 | 44,663 | 22.1 | 62,430 | 17,767 | 8.8 | 75,319 | 1,461 | 76,780 | 38.0 | 121,443 | 60.1 |
| 39 | 44,535 | 44,535 | 22.1 | 62,510 | 17,976 | 8.9 | 78,167 | 1,496 | 79,663 | 39.5 | 124,198 | 61.6 |
| 40 | 44,623 | 44,623 | 22.1 | 62,317 | 17,694 | 8.8 | 81,418 | 1,537 | 82,955 | 41.1 | 127,578 | 63.3 |
| 41 | 39,387 | 39,387 | 19.5 | 62,614 | 23,227 | 11.5 | 84,726 | 1,578 | 86,304 | 42.8 | 125,690 | 62.3 |
| 42 | 39,671 | 39,671 | 19.8 | 102,673 | 63,002 | 31.4 | 87,765 | 1,612 | 89,377 | 44.5 | 129,048 | 64.3 |
| 43 | | | | | | | | | | | | |
| 44 | | | | | | | | | | | | |
| 45 | 461,067 | 461,067 | | 500,438 | 39,372 | | 496,875 | 10,750 | 507,625 | | 968,692 | |
| 46 | | | 22.2 | | | 1.9 | | | | 24.5 | | 46.7 |
| 47 | | | 17.2 | | | 1.5 | | | | 19.0 | | 36.2 |

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# Rathdrum to CCCT w/4-LM6000 SCCTs

## Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | A | F | G | K | N | O | S | U | W | AB | AE | AG |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | Installed Cost | 262,762 | $000s | Fixed Charge | 0.01 | per kW-month | | | | | | |
| 7 | Project Capacity | 285.8 | MW | Fixed O&M | 0.90 | 2001$ per kW-month | | | | | | |
| 8 | Heat Rate (net change) | 6,282 | Btu/kWh | Escalation Rates | | | Insurance Cost | 788.3 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.8 | percent |
| 9 | Net Ann. Gas Useage | 46.6 | 000s dth/day | Fixed O&M | 2.6 | percent | Gas Transport | 0.24589 | 2001 $/dth/day | Real Discount Rate | 5.0 | percent |
| 10 | | | | Variable O&M | 2.6 | percent | Electric Wheeling | 0 | $/MW-month thru 2006 | | | |
| 11 | | | | Transportation | 2.0 | percent | General Inflation | 2.6 | percent | | | |

| | A | B | D | F | G | H | I | K | L | M | N | O | P | Q | S | T | U | W | Y | Z | AB | AC | AD | AE | AG | AH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14 | | | | Fixed Costs | | | | | | | | | | | Total Fixed Costs | | | Less | | | | | | | | |
| 15 | | | | Capital Recovery and Miscellaneous | | | | Operations & Maintenance | | | | | | | Before 10% | After 10% | After 10% | Operating | Net | | Variable Costs | | | | Total Project Cost | |
| 16 | Year | | Energy | Project | Fixed Chrg. | Total Costs | | Fixed | Gtrans | Etrans | PrTax | Insur. | Total Costs | | Credit | Credit | Credit | Margin | Project Benefit | | Gas | O&M | Total Variable | | after Credits | |
| 17 | | | (GWh) | ($000s) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($000s) | ($000s) | ($000s) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($/MWh) |
| 18 | 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 19 | 2 | 2002 | 301.6 | 24,607 | 0 | 24,607 | 81.6 | 1,868 | 2,133 | 0 | 2,202 | 472 | 6,676 | 22.1 | 31,283 | 31,283 | 103.7 | 21,923 | (9,361) | (31.0) | 25,417 | 598 | 26,015 | 86.3 | 57,298 | 190.0 |
| 20 | 3 | 2003 | 788.9 | 27,034 | 0 | 27,034 | 34.3 | 3,286 | 4,352 | 0 | 2,128 | 830 | 10,596 | 13.4 | 37,630 | 37,630 | 47.7 | 23,210 | (14,420) | (18.3) | 38,539 | 1,032 | 39,571 | 50.2 | 77,201 | 97.9 |
| 21 | 4 | 2004 | 1,676.5 | 38,412 | 0 | 38,412 | 22.9 | 3,371 | 4,439 | 0 | 3,925 | 851 | 12,587 | 7.5 | 50,999 | 50,999 | 30.4 | 41,579 | (9,420) | (5.6) | 58,685 | 3,755 | 62,440 | 37.2 | 113,439 | 67.7 |
| 22 | 5 | 2005 | 2,437.6 | 48,173 | 0 | 48,173 | 19.8 | 3,459 | 4,528 | 0 | 3,786 | 874 | 12,647 | 5.2 | 60,820 | 60,820 | 25.0 | 48,521 | (12,299) | (5.0) | 73,531 | 5,874 | 79,405 | 32.6 | 140,225 | 57.5 |
| 23 | 6 | 2006 | 2,500.4 | 46,830 | 0 | 46,830 | 18.7 | 3,549 | 4,619 | 0 | 3,648 | 896 | 12,712 | 5.1 | 59,541 | 59,541 | 23.8 | 51,622 | (7,919) | (3.2) | 79,333 | 6,075 | 85,408 | 34.2 | 144,949 | 58.0 |
| 24 | 7 | 2007 | 2,549.4 | 45,485 | 0 | 45,485 | 17.8 | 3,641 | 4,711 | 0 | 3,509 | 920 | 12,781 | 5.0 | 58,266 | 58,266 | 22.9 | 53,461 | (4,805) | (1.9) | 83,856 | 6,216 | 90,073 | 35.3 | 148,338 | 58.2 |
| 25 | 8 | 2008 | 2,555.0 | 44,186 | 0 | 44,186 | 17.3 | 3,736 | 4,805 | 0 | 3,371 | 943 | 12,856 | 5.0 | 57,042 | 57,042 | 22.3 | 54,990 | (2,052) | (0.8) | 88,088 | 6,424 | 94,512 | 37.0 | 151,554 | 59.3 |
| 26 | 9 | 2009 | 2,574.3 | 42,887 | 0 | 42,887 | 16.7 | 3,833 | 4,901 | 0 | 3,232 | 968 | 12,935 | 5.0 | 55,822 | 55,822 | 21.7 | 56,474 | 651 | 0.3 | 91,223 | 6,597 | 97,820 | 38.0 | 153,642 | 59.7 |
| 27 | 10 | 2010 | 2,623.0 | 41,649 | 0 | 41,649 | 15.9 | 3,933 | 4,999 | 0 | 3,094 | 993 | 13,019 | 5.0 | 54,668 | 54,668 | 20.8 | 59,254 | 4,586 | 1.7 | 94,781 | 6,777 | 101,558 | 38.7 | 156,226 | 59.6 |
| 28 | 11 | 2011 | 2,756.1 | 40,434 | 0 | 40,434 | 14.7 | 4,035 | 5,099 | 0 | 2,955 | 1,019 | 13,109 | 4.8 | 53,543 | 53,543 | 19.4 | 60,028 | 6,485 | 2.4 | 98,323 | 6,953 | 105,276 | 38.2 | 158,819 | 57.6 |
| 29 | 12 | 2012 | 2,847.6 | 39,252 | 0 | 39,252 | 13.8 | 4,140 | 5,201 | 0 | 2,817 | 1,045 | 13,204 | 4.6 | 52,456 | 52,456 | 18.4 | 66,448 | 13,992 | 4.9 | 102,252 | 7,151 | 109,403 | 38.4 | 161,859 | 56.8 |
| 30 | 13 | 2013 | 2,832.8 | 38,053 | 0 | 38,053 | 13.4 | 4,248 | 5,305 | 0 | 2,678 | 1,073 | 13,304 | 4.7 | 51,357 | 51,357 | 18.1 | 59,793 | 8,437 | 3.0 | 105,808 | 7,315 | 113,123 | 39.9 | 164,480 | 58.1 |
| 31 | 14 | 2014 | 2,873.9 | 36,896 | 0 | 36,896 | 12.8 | 4,358 | 5,412 | 0 | 2,540 | 1,101 | 13,410 | 4.7 | 50,306 | 50,306 | 17.5 | 61,054 | 10,748 | 3.7 | 110,231 | 7,501 | 117,732 | 41.0 | 168,038 | 58.5 |
| 32 | 15 | 2015 | 2,895.8 | 35,762 | 0 | 35,762 | 12.3 | 4,471 | 5,520 | 0 | 2,401 | 1,129 | 13,521 | 4.7 | 49,283 | 49,283 | 17.0 | 60,219 | 10,936 | 3.8 | 115,142 | 7,654 | 122,796 | 42.4 | 172,079 | 59.4 |
| 33 | 16 | 2016 | 2,887.3 | 34,608 | 0 | 34,608 | 12.0 | 4,588 | 5,630 | 0 | 2,263 | 1,158 | 13,639 | 4.7 | 48,247 | 48,247 | 16.7 | 59,991 | 11,744 | 4.1 | 119,609 | 7,844 | 127,454 | 44.1 | 175,701 | 60.9 |
| 34 | 17 | 2017 | 2,854.1 | 33,401 | 0 | 33,401 | 11.7 | 4,707 | 5,743 | 0 | 2,124 | 1,189 | 13,762 | 4.8 | 47,163 | 47,163 | 16.5 | 59,020 | 11,857 | 4.2 | 123,022 | 7,961 | 130,983 | 45.9 | 178,146 | 62.4 |
| 35 | 18 | 2018 | 2,853.4 | 32,228 | 0 | 32,228 | 11.3 | 4,829 | 5,858 | 0 | 1,986 | 1,220 | 13,892 | 4.9 | 46,120 | 46,120 | 16.2 | 59,353 | 13,233 | 4.6 | 127,080 | 8,155 | 135,234 | 47.4 | 181,355 | 63.6 |
| 36 | 19 | 2019 | 2,831.2 | 31,025 | 0 | 31,025 | 11.0 | 4,955 | 5,975 | 0 | 1,847 | 1,251 | 14,028 | 5.0 | 45,053 | 45,053 | 15.9 | 59,182 | 14,129 | 5.0 | 130,513 | 8,319 | 138,832 | 49.0 | 183,885 | 64.9 |
| 37 | 20 | 2020 | 2,753.8 | 29,802 | 0 | 29,802 | 10.8 | 5,084 | 6,094 | 0 | 1,709 | 1,284 | 14,170 | 5.1 | 43,973 | 43,973 | 16.0 | 68,215 | 24,242 | 8.8 | 133,557 | 8,474 | 142,031 | 51.6 | 186,004 | 67.5 |
| 38 | 21 | 2021 | 2,726.0 | 28,622 | 0 | 28,622 | 10.5 | 5,216 | 6,216 | 0 | 1,570 | 1,317 | 14,319 | 5.3 | 42,941 | 42,941 | 15.8 | 67,045 | 24,104 | 8.8 | 137,532 | 8,567 | 146,099 | 53.6 | 189,040 | 69.3 |
| 39 | 22 | 2022 | 2,728.9 | 27,532 | 0 | 27,532 | 10.1 | 5,351 | 6,340 | 0 | 1,432 | 1,351 | 14,475 | 5.3 | 42,006 | 42,006 | 15.4 | 66,145 | 24,139 | 8.8 | 141,760 | 8,655 | 150,416 | 55.1 | 192,422 | 70.5 |
| 40 | 23 | 2023 | 2,728.0 | 26,621 | 0 | 26,621 | 9.8 | 5,491 | 6,467 | 0 | 1,293 | 1,387 | 14,638 | 5.4 | 41,258 | 41,258 | 15.1 | 65,260 | 24,002 | 8.8 | 146,487 | 8,739 | 155,225 | 56.9 | 196,484 | 72.0 |
| 41 | 24 | 2024 | 2,736.1 | 25,915 | 0 | 25,915 | 9.5 | 5,633 | 6,597 | 0 | 1,155 | 1,423 | 14,807 | 5.4 | 40,722 | 40,722 | 14.9 | 64,811 | 24,090 | 8.8 | 152,391 | 8,896 | 161,287 | 58.9 | 202,008 | 73.8 |
| 42 | 25 | 2025 | 2,724.8 | 25,245 | 0 | 25,245 | 9.3 | 5,780 | 6,729 | 0 | 1,016 | 1,460 | 14,984 | 5.5 | 40,229 | 40,229 | 14.8 | 135,651 | 95,422 | 35.0 | 156,362 | 8,970 | 165,332 | 60.7 | 205,561 | 75.4 |
| 43 | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | *2001$* | | | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Net Present Value | | | 366,356 | 0 | 366,356 | | 38,668 | 48,463 | 0 | 27,417 | 9,765 | 124,313 | | 490,668 | 490,668 | | 519,981 | 29,313 | | 884,324 | 58,173 | 942,497 | | 1,433,165 | |
| 46 | Nominal Levelized Cost ($/MWh) | | | | | | 14.0 | | | | | | | 4.8 | | | 18.8 | | | 1.1 | | | | 36.0 | | 54.8 |
| 47 | Real Levelized Cost ($/MWh) | | | | | | 10.9 | | | | | | | 3.7 | | | 14.6 | | | 0.9 | | | | 28.0 | | 42.5 |

12-07-2000 Rathdrum to CC :Economics-Base6.xls cgk

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# Rathdrum to CCCT w/4-LM6000 SCCTs

## Avista Corporation

## Economic Analysis Detail

### Assumptions

| Row | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | Installed Cost | 230,049 | $000s | Fixed Charge | 0.01 | per kW-month | | | | | | |
| 7 | Project Capacity | 285.8 | MW | Fixed O&M | 0.90 | 2001$ per kW-month | | | | | | |
| 8 | Heat Rate (net change) | 6,262 | Btu/kWh | Escalation Rates | | | Insurance Cost | 690.1 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.8 | percent |
| 9 | Net Ann. Gas Useage | 46.6 | 000s dth/day | Fixed O&M | 2.6 | percent | Gas Transport | 0.24589 | 2001 $/dth/day | Real Discount Rate | 5.0 | percent |
| 10 | | | | Variable O&M | 2.6 | percent | Electric Wheeling | 0 | $/MW-month thru 2006 | | | |
| 11 | | | | Transportation | 2.0 | percent | General Inflation | 2.6 | percent | | | |

| Row | | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Fixed Costs – Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 19 | 2 | 2002 | 301.6 | 19,691 | 0 | 19,691 | 65.3 | 1,868 | 2,133 | 0 | 1,735 | 413 | 6,150 | 20.4 |
| 20 | 3 | 2003 | 788.9 | 21,779 | 0 | 21,779 | 27.6 | 3,286 | 4,352 | 0 | 1,676 | 726 | 10,041 | 12.7 |
| 21 | 4 | 2004 | 1,676.5 | 33,248 | 0 | 33,248 | 19.8 | 3,371 | 4,439 | 0 | 3,471 | 745 | 12,028 | 7.2 |
| 22 | 5 | 2005 | 2,437.6 | 43,103 | 0 | 43,103 | 17.7 | 3,459 | 4,528 | 0 | 3,349 | 765 | 12,101 | 5.0 |
| 23 | 6 | 2006 | 2,500.4 | 41,949 | 0 | 41,949 | 16.8 | 3,549 | 4,619 | 0 | 3,227 | 785 | 12,180 | 4.9 |
| 24 | 7 | 2007 | 2,549.4 | 40,786 | 0 | 40,786 | 16.0 | 3,641 | 4,711 | 0 | 3,105 | 805 | 12,263 | 4.8 |
| 25 | 8 | 2008 | 2,555.0 | 39,663 | 0 | 39,663 | 15.5 | 3,736 | 4,805 | 0 | 2,983 | 826 | 12,351 | 4.8 |
| 26 | 9 | 2009 | 2,574.3 | 38,533 | 0 | 38,533 | 15.0 | 3,833 | 4,901 | 0 | 2,861 | 847 | 12,443 | 4.8 |
| 27 | 10 | 2010 | 2,623.0 | 37,461 | 0 | 37,461 | 14.3 | 3,933 | 4,999 | 0 | 2,739 | 869 | 12,541 | 4.8 |
| 28 | 11 | 2011 | 2,756.1 | 36,412 | 0 | 36,412 | 13.2 | 4,035 | 5,099 | 0 | 2,617 | 892 | 12,644 | 4.6 |
| 29 | 12 | 2012 | 2,847.6 | 35,395 | 0 | 35,395 | 12.4 | 4,140 | 5,201 | 0 | 2,495 | 915 | 12,752 | 4.5 |
| 30 | 13 | 2013 | 2,832.8 | 34,361 | 0 | 34,361 | 12.1 | 4,248 | 5,305 | 0 | 2,373 | 939 | 12,865 | 4.5 |
| 31 | 14 | 2014 | 2,873.9 | 33,369 | 0 | 33,369 | 11.6 | 4,358 | 5,412 | 0 | 2,251 | 964 | 12,984 | 4.5 |
| 32 | 15 | 2015 | 2,895.8 | 32,400 | 0 | 32,400 | 11.2 | 4,471 | 5,520 | 0 | 2,129 | 989 | 13,109 | 4.5 |
| 33 | 16 | 2016 | 2,887.3 | 31,412 | 0 | 31,412 | 10.9 | 4,588 | 5,630 | 0 | 2,007 | 1,014 | 13,239 | 4.6 |
| 34 | 17 | 2017 | 2,854.1 | 30,369 | 0 | 30,369 | 10.6 | 4,707 | 5,743 | 0 | 1,885 | 1,041 | 13,375 | 4.7 |
| 35 | 18 | 2018 | 2,853.4 | 29,362 | 0 | 29,362 | 10.3 | 4,829 | 5,858 | 0 | 1,763 | 1,068 | 13,518 | 4.7 |
| 36 | 19 | 2019 | 2,831.2 | 28,324 | 0 | 28,324 | 10.0 | 4,955 | 5,975 | 0 | 1,641 | 1,095 | 13,666 | 4.8 |
| 37 | 20 | 2020 | 2,753.8 | 27,267 | 0 | 27,267 | 9.9 | 5,084 | 6,094 | 0 | 1,519 | 1,124 | 13,821 | 5.0 |
| 38 | 21 | 2021 | 2,726.0 | 26,251 | 0 | 26,251 | 9.6 | 5,216 | 6,216 | 0 | 1,397 | 1,153 | 13,982 | 5.1 |
| 39 | 22 | 2022 | 2,728.9 | 25,310 | 0 | 25,310 | 9.3 | 5,351 | 6,340 | 0 | 1,275 | 1,183 | 14,150 | 5.2 |
| 40 | 23 | 2023 | 2,728.0 | 24,515 | 0 | 24,515 | 9.0 | 5,491 | 6,467 | 0 | 1,153 | 1,214 | 14,325 | 5.3 |
| 41 | 24 | 2024 | 2,736.1 | 23,907 | 0 | 23,907 | 8.7 | 5,633 | 6,597 | 0 | 1,031 | 1,245 | 14,506 | 5.3 |
| 42 | 25 | 2025 | 2,724.8 | 23,334 | 0 | 23,334 | 8.6 | 5,780 | 6,729 | 0 | 909 | 1,278 | 14,695 | 5.4 |
| 43 | | | | | | | | | | | | | | |
| 44 | *2001$* | | | | | | | | | | | | | |
| 45 | Net Present Value | | | 325,254 | 0 | 325,254 | | 38,668 | 48,463 | 0 | 23,933 | 8,549 | 119,613 | |
| 46 | Nominal Levelized Cost ($/MWh) | | | | | | 12.4 | | | | | | | 4.6 |
| 47 | Real Levelized Cost ($/MWh) | | | | | | 9.6 | | | | | | | 3.5 |

| Row | Year | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 19 | 2002 | 25,841 | 25,841 | 85.7 | 21,923 | (3,919) | (13.0) | 25,417 | 598 | 26,015 | 86.3 | 51,856 | 171.9 |
| 20 | 2003 | 31,820 | 31,820 | 40.3 | 23,210 | (8,611) | (10.9) | 38,539 | 1,032 | 39,571 | 50.2 | 71,391 | 90.5 |
| 21 | 2004 | 45,275 | 45,275 | 27.0 | 41,579 | (3,696) | (2.2) | 58,685 | 3,755 | 62,440 | 37.2 | 107,715 | 64.3 |
| 22 | 2005 | 55,205 | 55,205 | 22.6 | 48,521 | (6,684) | (2.7) | 73,531 | 5,874 | 79,405 | 32.6 | 134,610 | 55.2 |
| 23 | 2006 | 54,129 | 54,129 | 21.6 | 51,622 | (2,507) | (1.0) | 79,333 | 6,075 | 85,408 | 34.2 | 139,536 | 55.8 |
| 24 | 2007 | 53,049 | 53,049 | 20.8 | 53,461 | 412 | 0.2 | 83,856 | 6,216 | 90,073 | 35.3 | 143,121 | 56.1 |
| 25 | 2008 | 52,014 | 52,014 | 20.4 | 54,990 | 2,977 | 1.2 | 88,088 | 6,424 | 94,512 | 37.0 | 146,526 | 57.3 |
| 26 | 2009 | 50,977 | 50,977 | 19.8 | 56,474 | 5,497 | 2.1 | 91,223 | 6,597 | 97,820 | 38.0 | 148,796 | 57.8 |
| 27 | 2010 | 50,002 | 50,002 | 19.1 | 59,254 | 9,252 | 3.5 | 94,781 | 6,777 | 101,558 | 38.7 | 151,559 | 57.8 |
| 28 | 2011 | 49,056 | 49,056 | 17.8 | 60,028 | 10,973 | 4.0 | 98,323 | 6,953 | 105,276 | 38.2 | 154,332 | 56.0 |
| 29 | 2012 | 48,147 | 48,147 | 16.9 | 66,448 | 18,301 | 6.4 | 102,252 | 7,151 | 109,403 | 38.4 | 157,550 | 55.3 |
| 30 | 2013 | 47,226 | 47,226 | 16.7 | 59,793 | 12,567 | 4.4 | 105,808 | 7,315 | 113,123 | 39.9 | 160,349 | 56.6 |
| 31 | 2014 | 46,354 | 46,354 | 16.1 | 61,054 | 14,700 | 5.1 | 110,231 | 7,501 | 117,732 | 41.0 | 164,086 | 57.1 |
| 32 | 2015 | 45,509 | 45,509 | 15.7 | 60,219 | 14,710 | 5.1 | 115,142 | 7,654 | 122,796 | 42.4 | 168,305 | 58.1 |
| 33 | 2016 | 44,651 | 44,651 | 15.5 | 59,991 | 15,340 | 5.3 | 119,609 | 7,844 | 127,454 | 44.1 | 172,105 | 59.6 |
| 34 | 2017 | 43,745 | 43,745 | 15.3 | 59,020 | 15,275 | 5.4 | 123,022 | 7,961 | 130,983 | 45.9 | 174,728 | 61.2 |
| 35 | 2018 | 42,880 | 42,880 | 15.0 | 59,353 | 16,473 | 5.8 | 127,080 | 8,155 | 135,234 | 47.4 | 178,114 | 62.4 |
| 36 | 2019 | 41,990 | 41,990 | 14.8 | 59,182 | 17,192 | 6.1 | 130,513 | 8,319 | 138,832 | 49.0 | 180,822 | 63.9 |
| 37 | 2020 | 41,088 | 41,088 | 14.9 | 68,215 | 27,127 | 9.9 | 133,557 | 8,474 | 142,031 | 51.6 | 183,119 | 66.5 |
| 38 | 2021 | 40,234 | 40,234 | 14.8 | 67,045 | 26,811 | 9.8 | 137,532 | 8,567 | 146,099 | 53.6 | 186,332 | 68.4 |
| 39 | 2022 | 39,460 | 39,460 | 14.5 | 66,145 | 26,685 | 9.8 | 141,760 | 8,655 | 150,416 | 55.1 | 189,876 | 69.6 |
| 40 | 2023 | 38,840 | 38,840 | 14.2 | 65,260 | 26,420 | 9.7 | 146,487 | 8,739 | 155,225 | 56.9 | 194,065 | 71.1 |
| 41 | 2024 | 38,413 | 38,413 | 14.0 | 64,811 | 26,398 | 9.6 | 152,391 | 8,896 | 161,287 | 58.9 | 199,700 | 73.0 |
| 42 | 2025 | 38,029 | 38,029 | 14.0 | 128,058 | 90,029 | 33.0 | 156,362 | 8,970 | 165,332 | 60.7 | 203,362 | 74.6 |
| 43 | | | | | | | | | | | | | |
| 44 | *2001$* | | | | | | | | | | | | |
| 45 | Net Present Value | 444,867 | 444,867 | | 518,812 | 73,945 | | 884,324 | 58,173 | 942,497 | | 1,387,364 | |
| 46 | Nominal Levelized Cost ($/MWh) | | | 17.0 | | | 2.8 | | | | 36.0 | | 53.1 |
| 47 | Real Levelized Cost ($/MWh) | | | 13.2 | | | 2.2 | | | | 28.0 | | 41.2 |



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Table 1

## RFP Evaluation Economics

## 3rd Screening Evaluation Comparison to 2nd Screening (Base Case)

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| Bid No. | Bidder | Project Type | Capacity (MW) | Term (years) | Project NLC Savings (Costs) * 2nd Screen ($/MWh) | Screen 2A ($/MWh) | 3rd Screen ($/MWh) |
|---|---|---|---|---|---|---|---|
| 25a | RCT Upgrades @ Rathdrum | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | (1.00) | (4.40) | 2.80 |
| 25c | Delayed RCT Upgrades @ Rathdrum | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | NA | (4.60) | 2.70 |
| 24 | CS2 CCCT | Coyote Springs CCCT | 280.0 | Turnkey | (3.60) | (4.60) | 1.90 |
| 25b | RCT Upgrades w/2-LM6000s @ NE | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | NA | (6.60) | 1.10 |
| 25d | Delayed RCT Upgrades w/2-LM6000s @ NE | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | NA | (7.20) | 0.80 |
| 14 | PG&E Bid #1 Flat Purchase | Flat Purchase | 300.0 | 10 | (1.60) | (4.70) | 0.80 |
| 5 | Enron Bid #1 Flat Purchase | Flat Purchase | 300.0 | 20 | (5.30) | (6.20) | (0.30) |
| 21 | Williams Bid #1 Flat Purchase | Flat Purchase | 300.0 | 20 | (1.50) | (6.80) | (0.90) |
| 10 | Enron #6 Turnkey | CCCT Turnkey | 249.0 | Turnkey | (5.30) | (12.50) | (4.30) |

Explanation of Screened Scenarios

2nd Screen—final economic results used in 2nd screening process using Henwood and Associates price forecasts.
Screen 2A—3rd Screening capital and operating costs using Henwood price forecasts. This scenario was run to determine the ultimate impacts of shifting from the Henwood to R.W. Beck market foreast.
3rd Screen—final economic results used in the 3rd screening process using R.W. Beck price forecasts

**Table 2**

## RFP Evaluation Economics

## 3rd Screening Evaluation with Sensitivities

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| Bid No. | Bidder | Project Type | Capacity (MW) | Term (years) | Nominal Levelized Cost: Base Case ($/MWh) | High Fuel ($/MWh) | Low Fuel ($/MWh) | High Load ($/MWh) |
|---|---|---|---|---|---|---|---|---|
| 25a | RCT Upgrades @ Rathdrum | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | 2.80 | 4.70 | 3.20 | 4.70 |
| 25c | Delayed RCT Upgrades @ Rathdrum | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | 2.70 | 4.60 | 3.10 | 4.50 |
| 24 | CS2 CCCT | Coyote Springs CCCT | 280.0 | Turnkey | 1.90 | 4.50 | 1.60 | 3.80 |
| 25b | RCT Upgrades w/2-LM6000s @ NE | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | 1.10 | 3.10 | 1.30 | 3.00 |
| 25d | Delayed RCT Upgrades w/2-LM6000s @ NE | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | 0.80 | 2.80 | 1.00 | 2.60 |
| 14 | PG&E Bid #1 Flat Purchase | Flat Purchase | 300.0 | 10 | 0.80 | 9.40 | (7.90) | 1.60 |
| 5 | Enron Bid #1 Flat Purchase | Flat Purchase | 300.0 | 20 | (0.30) | 8.20 | (6.70) | 1.50 |
| 21 | Williams Bid #1 Flat Purchase | Flat Purchase | 300.0 | 20 | (0.90) | 7.70 | (7.20) | 0.90 |
| 10 | Enron #6 Turnkey | CCCT Turnkey | 249.0 | Turnkey | (4.30) | (1.50) | (4.60) | (2.30) |



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**Table 3**

## RFP Evaluation Economics

### 3rd Screening Evaluation Comparison to 2nd Screening (Base Case)

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| Bid No. | Bidder | Project Type | Capacity (MW) | Term (years) | Total Project NLC Cost: 2nd Screen ($/MWh) | Total Project NLC Cost: 3rd Screen ($/MWh) |
|---|---|---|---|---|---|---|
| 25a | RCT Upgrades @ Rathdrum | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | 44.6 | 53.1 |
| 25c | Delayed RCT Upgrades @ Rathdrum | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | NA | 50.5 |
| 24 | CS2 CCCT | Coyote Springs CCCT | 280.0 | Turnkey | 46.9 | 46.7 |
| 25b | RCT Upgrades w/2-LM6000s @ NE | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | NA | 54.8 |
| 25d | Delayed RCT Upgrades w/2-LM6000s @ NE | Rathdrum Conversion w/4-LM6000s | 285.8 | Turnkey | NA | 52.5 |
| 14 | PG&E Bid #1 Flat Purchase | Flat Purchase | 300.0 | 10 | 41.9 | 56.9 |
| 5 | Enron Bid #1 Flat Purchase | Flat Purchase | 300.0 | 20 | 45.6 | 47.2 |
| 21 | Williams Bid #1 Flat Purchase | Flat Purchase | 300.0 | 20 | 41.8 | 47.8 |
| 10 | Enron #6 Turnkey | CCCT Turnkey | 249.0 | Turnkey | 47.2 | 51.0 |

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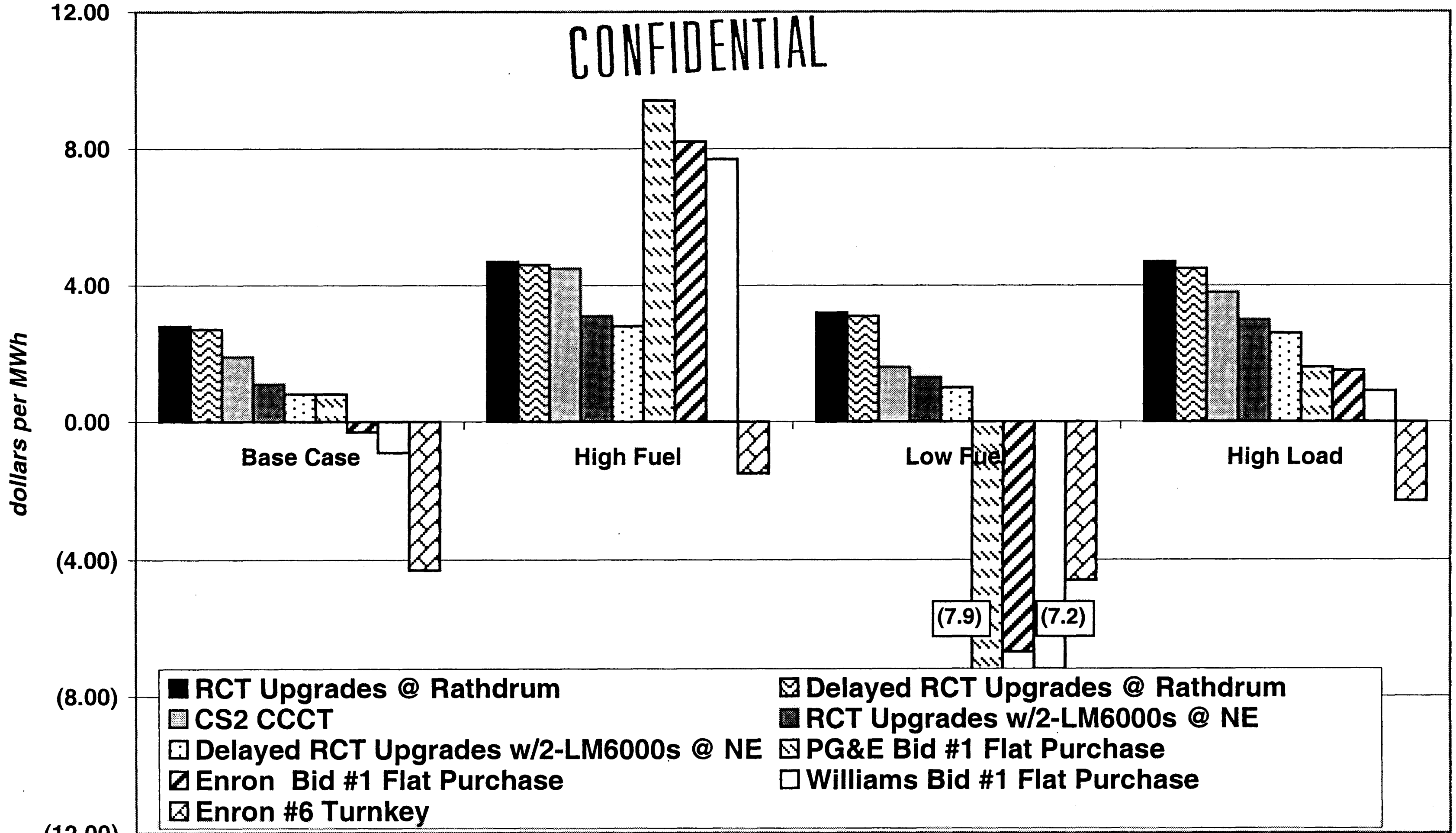
Exhibit 4

RFP 3rd Screening Sensitivity Analysis

2001-25 Nominal Levelized Annual Savings *




* relative to present resource portfolio

*12-06-2000 Matrix5-Final.xls cgk*

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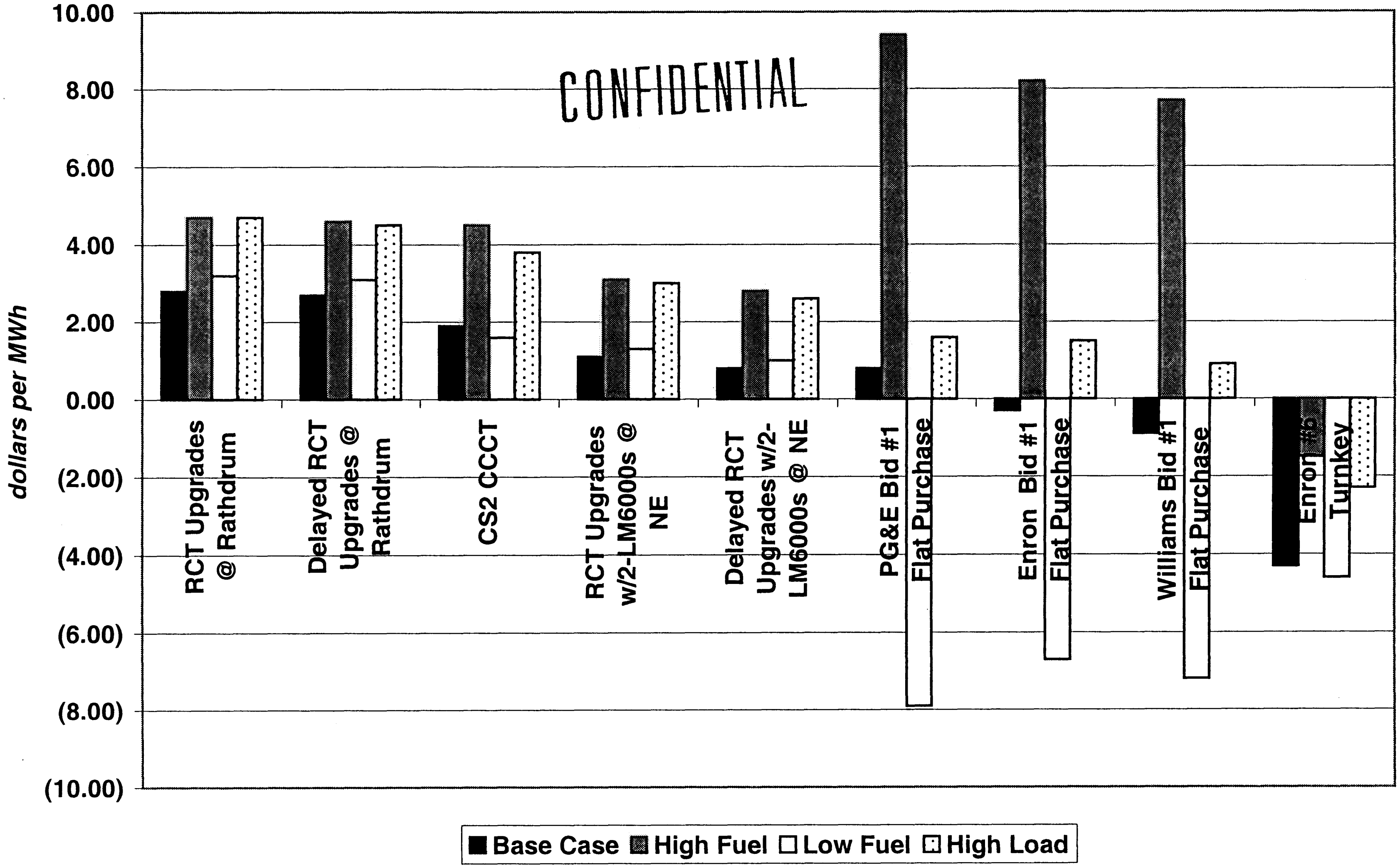
# Exhibit 5
## RFP 3rd Screening Sensitivity Analysis
### 2001-25 Nominal Levelized Annual Savings *




* relative to present resource portfolio

*12-06-2000 Matrix5-Final.xls cgk*

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DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-C9)

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**Resource Planning & Acquisition Documentation Index**

## Avista Corp.
## 1999-2000 Planning & Determination of Resource Need

| | | |
|---|---|---|
| Book 1 | 09-21-1993 | WUTC-Doc.No. WE-920433 PSE - PRAM Filing |
| | 09-27-1994 | WUTC-Doc.No. WE-920433 PSE - PRAM Filing |
| | 01-01-1998 | WSCC - Summary of Estimated Loads & Resources |
| Book 2 | 1998 | BPA "White Book" Regional Load Data |
| | 1998 | BPA Pacific Northwest Loads & Resources Study |
| | 1998-2007 | 10 year Coordination Plan |
| | Spring 2000 | PNUCC NW Regional Forecast |
| | Mar-00 | WUTC Centralia Sale Order |
| | 03-06-2000 | NW Power Supply Adequacy/Reliability Study Phase I |
| | 05-02-2000 | Prudence |
| Book 3 | 05-10-2000 | 2004 L&R data |
| | 05-23-2000 | WUTC Staff Mtg. |
| | 06-02-2000 | IPUC Mtg. |
| | 06-22-2000 | IRP Tac Mtg. |
| | 06-26-2000 | 1997 IRP Update Draft |
| | 06-27-2000 | WUTC Staff-Prosym Data |
| | 07-06-2000 | WUTC Staff-RFP Draft |
| | 07-06-2000 | Carbon Tax Info |
| | 07-11-2000 | WUTC-1997 IRP Update Filing |
| | 07-11-2000 | IPUC-RFP/IRP Filing |
| | 07-12-2000 | WUTC Filing |
| Book 4 | 07-12-2000 | Avista-RFP Request for Comments Letter |
| | 07-18-2000 | WUTC - Request for Comments |
| | 07-21-2000 | IPUC - Request for Comments |
| | 07-25-2000 | WUTC Data Request |
| | 07-31-2000 | WUTC Data Request |
| | 08-02-2000 | IPUC Mtg. |
| | 08-03-2000 | WUTC Data Request |
| | 08-04-2000 | WUTC/IPUC Revised RFP Filing |
| | 08-07-2000 | NWEC RFP Comments |
| | 08-09-2000 | WUTC Staff Recommendation |
| | 08-09-2000 | WUTC-RFP Approval |
| | 08-11-2000 | IPUC -Staff Recommendations |
| | 08-14-2000 | RFP Clearing-Up |
| | 08-14-2000 | RFP Advertisements |
| | 08-15-2000 | RFP Evaluation Process Outline |
| | 09-13-2000 | WUTC/IPUC Staff Review RFP Evaluation Process |
| | 09-14-2000 | WUTC Request for Confidentiality |
| | 09-18-2000 | RFP-Williams-Avista Guidelines |
| | 09-18-2000 | RFP-APS decling participation |
| | 10-10-2000 | IPUC-RFP Acknowledgement |

## Avista Corp.
## 2000 Resources & Miscellaneous

### Combined Cycle Combustion Turbine Site Evaluation Study

| | | |
|---|---|---|
| Book 1 | | Vanalco |
| | | Starbuck |
| | | Alcoa |
| | | N.W. Power Enterprises |
| | | Hermiston Power Partners |
| | | Kaiser Mead |
| | | NESCO |
| | | Calpine |
| | | EPSEC |
| | | ESI |
| | | Hermiston Power Partners |
| | | BPA |
| | | Satsop |
| | | Transmission |
| | | Longview Reynolds |
| | | Longview Weyerhauser |
| | | RCT |
| | | I-5 Corridor |
| | | Everett |
| | | Legislative |
| | | Creston |
| | | Coyote Springs |
| | | NECT |
| | | Energy N.W. |
| Book 2 | | Misc. Avista Siting Study Data |
| | 02-25-2000 | Avista-CCCT Initial Siting Study |
| | | BPA Transmission Studies |
| | 04-21-2000 | Dames & Moore Report |

## Avista Corp.
## 2000 Resource Evaluations & Decisions - Supply Side

### RFP Evaluation & Decision

| | | |
|---|---|---|
| Book 1 - RFP Analysis & Evaluation | 09-15-2000 | Evaluation Guidance for Electric RFP |
| | 09-22-2000 | WUTC Initial Screening Review |
| | 10-05-2000 | WUTC Conf. Call RFP Evaluation Review |
| | 10-12-2000 | 2nd screening evaluation Matrix Notes |
| | 10-12-2000 | 2nd Screening -Sent to IPUC |
| | 10-17-2000 | Cycles in Competition electricity Markets-Andrew Ford |
| | 10-18-2000 | WUTC/IPUC 2nd Screening Matrices & Economics |
| | 10-18-2000 | IPUC-Electric & Natural Gas Price Forecast Comparisons |
| | 10-18-2000 | IPUC Conf. Call 2nd Screening Review |
| | 10-20-2000 | WUTC Conf. Call 2nd Screening Review |
| | 10-27-2000 | WUTC -RFP Evaluation Responses to Questions |
| | 11-08-2000 | Avista Transmission Request Rathdrum |
| | 11-09-2000 | WUTC/IPUC Load & Resource Update |
| | 11-09-2000 | WUTC/IPUC L&R Data Transmittal |
| | 11-09-2000 | Tele-Conference Mtg. |
| | 11-09-2000 | Transmittal of Proposal |
| | 11-09-2000 | WUTC/IPUC Electric & Natural Gas Price Forecast Comparisons |
| | 11-20-2000 | Avista Transmission Request Response |
| | 11-20-2000 | Reserves Analysis |
| | 11-28-2000 | WUTC/IPUC RFP Third Round Screening Update |
| | 11-28-2000 | Avista Transmission Integration Request & Response |
| | 11-29-2000 | WUTC/IPUC Update Meeting Handouts |
| | 11-29-2000 | Commission hand-outs |
| | 12-06-2000 | WUTC/IPUC Final RFP Economic Matrixes |
| | 12-07-2000 | IPUC Economic Spreadsheets Rathdrum & Coyote Springs |
| | 12-10-2000 | RFP Evaluation Matrix |
| | 12-13-2000 | IPUC 2001 L&R |
| | 12-18-2000 | Natural Gas Transportation Costs |
| | 12-19-2000 | Rev. Requirement Impacts for Top Options |
| | | Archive of RFP Bid Proposals |
| Book 2 - Henwood Price Forecast | 09-22-2000 | Elec. Price Forecast |
| | 12-21-2000 | Elec. Price Forecast Supplement |
| Book 3 - R.W. Beck Services | 12-07-2000 | RFP Bid Analysis Review |
| | 01-08-2001 | Market Price Forecast Assumptions & Methodology |

### RFP Proposals & Avista Options

# CONFIDENTIAL

**Resource Planning & Acquisition Documentation Index**

| | | |
|---|---|---|
| Book 1 - PP&L Montana; TransAlta; and WSU (DSM) | 09-22-2000 | Bid proposal-Duke |
| | 09-22-2000 | Bid proposal-PP&L |
| | 09-22-2000 | Bid proposal-TransAlta |
| | 09-22-2000 | Ltr. Declining bid proposal |
| | 09-22-2000 | Ltr. Declining bid proposal |
| | 10-02-2000 | Notes from Doug Young regarding a ltr. Informing that they didn't meet screening for RFP |
| Book 2- Yanke Energy | 09-22-2000 | Bid proposal |
| | 09-27-2000 | Summary template of bid proposal |
| | 10-18-2000 | Ltr. declining bid proposal |
| Book 3 - PG&E | 09-11-2000 | Credit report info. |
| | 09-22-2000 | Bid Proposal |
| | 09-27-2000 | Summary template of bid proposal |
| | 10-11-2000 | Economic analysis as sent to R.W. Beck |
| | 10-17-2000 | Financial performance capability |
| | 10-18-2000 | Preliminary short list ltr. |
| | 10-24-2000 | Price update |
| | 11-21-2000 | 3rd screening economic analysis of short list bidders as presented to commission staff Nov. 29, 2000 |
| | 11-28-2000 | 3rd screening economic analysis (final) as referenced by Dec. 6, 2000 memo |
| | 12-11-2000 | Final decision ltr. |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |
| Book 4 - Enron | 06-21-2000 | Credit Review Summary |
| | 09-22-2000 | Bid Proposal |
| | 09-27-2000 | Initial Screening |
| | 10-12-2000 | Economic Analysis |
| | 10-18-2000 | Preliminary Short-List Ltr. |
| | 11-21-2000 | Economic Analysis |
| | 11-28-2000 | Economic Analysis |
| | 12-01-2000 | More Power News Article |
| | 12-04-2000 | Summary of Environmental Issues from Hank Nelson |
| | 12-11-2000 | Final Evaluation Letter |
| | 12-15-2000 | Combined Cycle Estimate |
| | 12-15-2000 | Analysis Assumption Detail |
| | 12-15-2000 | Cost Assumptions for Turnkey Upgrades |
| Book 5- Northwest Geothermal Company | 09-18-2000 | Proposal for Geothermal Baseload Power Sales to Avista |
| | 09-26-2000 | Summary template of bid proposal |
| | 10-10-2000 | Information regarding transmission control area services and degradation |
| | 10-11-2000 | Economic Analysis as sent to R.W. Beck |
| | 10-18-2000 | Avista's RFP Preliminary short list refusal letter |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |

# CONFIDENTIAL

## Resource Planning & Acquisition Documentation Index

| | | |
|---|---|---|
| Book 6- Empire Lumber | 09-22-2000 | Bid Proposal |
| | 09-27-2000 | Summary Template of Bid Proposal |
| | 10-11-2000 | Economic Analysis as sent to R.W. Beck |
| | 10-18-2000 | Denial letter |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |

**Resource Planning & Acquisition Documentation Index**

| | | |
|---|---|---|
| Book 7- Regional Power, Inc. | 09-26-2000 | Summary template of bid proposal |
| | 09-26-2000 | Bid proposal |
| | 10-04-2000 | Additional hydroflow data-statistics for the project |
| | 10-12-2000 | Economic Analysis as sent to R.W. Beck |
| | 10-13-2000 | Memo from Corporate on Regional's credit worthiness |
| | 10-18-2000 | Letter of confirmation that company made the preliminary short list |
| | 11-20-2000 | Regional Power's Response to Avista's RFP |
| | 12-11-2000 | Final Decision Letter |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |
| Book 8- Pacific Winds | 09-22-2000 | Bid Proposal |
| | 09-27-2000 | Summary template of bid proposal |
| | 10-11-2000 | Economic analysis as sent to R.W. Beck |
| Book 9- Williams | 09-18-2000 | Bid proposal |
| | 09-26-2000 | Summary template of bid proposal |
| | 10-11-2000 | Economic analysis as sent to R.W. Beck |
| | 10-18-2000 | Letter of confirmation that company made the preliminary short list |
| | 11-22-2000 | Economic analysis |
| | 11-22-2000 | Williams Response to Avista's RFP |
| | 11-28-2000 | Economic analysis |
| | 12-11-2000 | RFP final decision letter |
| | 12-15-2000 | Analysis assumption |
| | 12-15-2000 | 3rd screening economic analysis of short list bidders as presented to commission staff Nov. 29, 2000 |
| Book 10- Engage | 09-10-1999 | Credit Report info. |
| | 09-22-2000 | Bid proposal |
| | 09-27-2000 | Summary template of bid proposal |
| | 10-12-2000 | Economic analysis |
| | 10-18-2000 | Denial letter |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |
| Book 11- Newport Northwest | 09-22-2000 | Bid proposal |
| | 09-27-2000 | Summary template of bid proposal |
| | 10-11-2000 | Economic analysis as sent to R.W. Beck |
| | 10-13-2000 | Memo on credit from Corp. Finance Dept. |
| | 10-19-2000 | Credit Info. |
| | 10-20-2000 | Power Plant Article |
| | 11-10-2000 | Memo from P. Kimball to B. Lafferty Re: Newport NW Financial Support |
| | 11-21-2000 | 3rd screening economic analysis of short list bidders as presented to commission staff Nov. 29, 2000 |
| | 11-27-2000 | Williams Response to Avista's RFP |
| | 12-11-2000 | Final Evaluation/Decision |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |

## Resource Planning & Acquisition Documentation Index

| | | |
|---|---|---|
| Book 12- Calpine | 09-15-2000 | Bid proposal |
| | 09-26-2000 | Summary template of bid proposal |
| | 10-12-2000 | Economic analysis as sent to R.W. Beck |
| | 10-18-2000 | Avista's denial letter |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |
| Book 13- Sumas Energy | 09-27-2000 | Estimated availability by year for years 1-6 |
| | 09-22-2000 | Bid proposal |
| | 09-27-2000 | Summary template of bid proposal |
| | 10-08-2000 | Economic analysis as sent to R.W. Beck |
| | 10-18-2000 | Denial Ltr. |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |
| Book 14- Continental | 09-26-2000 | Summary template of bid proposal |
| | 09-26-2000 | Bid proposal |
| | 10-08-2000 | Economic analysis as sent to R.W. Beck |
| | 10-18-2000 | Avista's RFP preliminary short list refusal letter |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |
| Book 15- Rathdrum | 09-12-2001 | Rathdrum CT Spare Parts Analysis |
| | 10-12-2000 | Economic analysis as sent to R.W. Beck |
| | 10-16-2000 | Signed copy of confidentiality agreement between Avista and NEPCO |
| | 11-21-2000 | Economic Analysis |
| | 11-22-2000 | Sample letter to talk about expanding Rathdrum Site and Area mailing list/news article |
| | 11-22-2000 | 3rd screening economic analysis of short list bidders |
| | 11-28-2000 | Kootenai Environmental Mtg. |
| | 11-30-2000 | Rathdrum Neighborhood Mtg. |
| | 12-04-2000 | Note to file from Hank Nelson |
| | 12-06-2000 | 3rd screening economic analysis (final) as referenced by December 6, 2000 Memo from Bob L. |
| | 12-07-2000 | Paul Anderson Letter |
| | 12-15-2000 | Basic economic analysis assumptions for 3rd screening |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |
| | 12-22-2000 | Glenn Miller Sample Ltr., Mtg. W/ Mayor of Rathdrum, mailing list |
| | 12-22-2000 | Construction cost estimates for Rathdrum summaries: 1) All @ Rathdrum site; & 2) 2LM-6000's |
| Book 16- Coyote Springs | 08-01-2000 | Analysis of May 2002 completion |
| | 10-11-2000 | Economic Analysis as sent to R.W. Beck |
| | 11-14-2000 | Final Cost Comparison & Explanation of Screening for CS2 from Paul Kimball |
| | 11-21-2000 | Note from Alan Meyers re: Coyote ground lease |
| | 11-21-2000 | 3rd screening economic analysis of short list bidders as presented to commission staff Nov. 29, 2000 |
| | 12-04-2000 | Note to file from hank Nelson |
| | 12-06-2000 | 3rd screening economic analysis (final) |
| | 12-12-2000 | News Release |
| | 12-15-2000 | Basic economic analysis assumptions for 3rd screening |
| | 12-15-2000 | Basic economic analysis assumptions for 2nd screening |
| | 11-16-2001 | Fall 2001 CSII re-evaluation |

# CONFIDENTIAL

## Resource Planning & Acquisition Documentation Index

| | | |
|---|---|---|
| Book 17-<br>Kettle Falls | 02-14-2000 | Kettle Falls Upgrade Analysis Summary |
| | 09-12-2001 | Re-Evaluation |
| | 09-14-2001 | Decision to Delay Commercial Operations |

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-C10)

**CONFIDENTIAL**

**AVISTA Corp.**

***Energy Resources***

Date: December 19, 2000

To: Bob Lafferty

From: Bill Johnson

Re: Estimated Revenue Requirement Impacts

Attached are estimates of the impact on revenue requirements for the three RFP finalists. The estimates were calculated based on the following assumptions:

1) Fixed costs and O&M costs are from RFP evaluation analyses.
2) Generation is from RFP evaluation analyses.
3) Coyote Springs II comes on-line July 2002.
4) The Rathdrum LM 6000s are on-line Jan. 2004. HRSG is on-line Jan. 2005.
5) PG&E Flat Purchase begins Jan. 2004.
6) 2002-2009 Electric prices are from 11-30-00 forward prices in Riskworks.
7) 2002-2009 Gas prices are based on John Watts 2002-2006 price estimate (see 11-22-00 memo).
8) Long –term (lifecycle) electric and gas prices are from RFP evaluation analyses.

These calculations are estimates only. Actual impacts on revenue requirements will depend on actual capital expenditures and actual electric and gas prices.

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**Avista Corp.**
**Power Cost Impacts - Revenue Requirement**
**First 5 Years and Lifecycle**

| | Coyote 2 CCCT | Rathdrum CCCT w/ 4 LM 6000s (2 + 2) | PG&E Flat Purchase |
|---|---|---|---|
| **1st Full Year of Operation (1)** | 2003 | 2005 | 2004 |
| **5 Year Power Cost Impacts (2)** | | | |
| 2002 | -$28,821,176 | | |
| 2003 | -$26,345,851 | | |
| 2004 | -$7,944,607 | $3,732,121 | -$21,945,138 |
| 2005 | $2,204,855 | -$7,001,246 | -$7,873,145 |
| 2006 | $6,541,295 | $5,592,092 | -$1,540,747 |
| 2007 | $6,078,715 | $3,686,270 | -$1,447,747 |
| 2008 | | $2,739,780 | -$1,443,747 |
| 2009 | | $1,413,950 | |
| Levelized (Initial 5 or 6 years) | -$9,829,663 | $1,594,409 | -$7,577,498 |
| **Lifecycle Power Cost Impacts (3)** | | | |
| Levelized 25 Years | -$3,616,000 | -$3,968,000 | -$822,000 |

1) Coyote Springs II projected on-line date July, 2002. Rathdrum includes LM 6000s only in 2004.

2) 5 and 6 year impacts based on 11-30-00 forward electric prices (Riskworks) and 2002 - 2006 gas purchase cost of $3.45/Mmbtu (John Watts, 11-22-00).

3) Lifecycle impacts based on R.W. Beck electric and gas price projections.

CONFIDENTIAL

**PG&E Purchase**
**Power Cost Impact**
**2004 - 2008**

| | | | | | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 4912 | 416 | 384 | 432 | 400 | 416 | 416 | 400 | 432 | 400 | 416 | 400 | 400 |
| | | | | | 3848 | 328 | 288 | 312 | 319 | 328 | 304 | 344 | 312 | 320 | 329 | 320 | 344 |
| | | | | | 8760 | 744 | 672 | 744 | 719 | 744 | 720 | 744 | 744 | 720 | 745 | 720 | 744 |
| Generation | HLH | | | | 1,473,600 | 124,800 | 115,200 | 129,600 | 120,000 | 124,800 | 124,800 | 120,000 | 129,600 | 120,000 | 124,800 | 120,000 | 120,000 |
| Generation | LLH | | | | 1,154,400 | 98,400 | 86,400 | 93,600 | 95,700 | 98,400 | 91,200 | 103,200 | 93,600 | 96,000 | 98,700 | 96,000 | 103,200 |
| | | | | | 2,628,000 | | | | | | | | | | | | |
| Revenue | | 2004 | | | $140,719,938 | $18,607,144 | $11,562,834 | $11,453,500 | $7,847,982 | $7,242,432 | $10,787,602 | $13,419,936 | $16,246,948 | $14,008,068 | $11,257,238 | $9,009,252 | $9,277,002 |
| Revenue | | 2005 | | | $126,647,945 | $16,746,430 | $10,406,551 | $10,308,150 | $7,063,184 | $6,518,189 | $9,708,841 | $12,077,942 | $14,622,253 | $12,607,261 | $10,131,514 | $8,108,327 | $8,349,302 |
| Revenue | | 2006 | | | $120,315,547 | $15,909,108 | $9,886,223 | $9,792,743 | $6,710,025 | $6,192,280 | $9,223,399 | $11,474,045 | $13,891,140 | $11,976,898 | $9,624,939 | $7,702,910 | $7,931,837 |
| Revenue | | 2007 | | | $120,315,547 | $15,909,108 | $9,886,223 | $9,792,743 | $6,710,025 | $6,192,280 | $9,223,399 | $11,474,045 | $13,891,140 | $11,976,898 | $9,624,939 | $7,702,910 | $7,931,837 |
| Revenue | | 2008 | | | $120,315,547 | $15,909,108 | $9,886,223 | $9,792,743 | $6,710,025 | $6,192,280 | $9,223,399 | $11,474,045 | $13,891,140 | $11,976,898 | $9,624,939 | $7,702,910 | $7,931,837 |
| | | | | $/MWh | $/Year | | | | | | | | | | | | |
| Purchase Expense | | | $41.45 | $41.45 | $108,919,800 | 9,250,723 | 8,355,492 | 9,250,723 | 8,939,879 | 9,250,723 | 8,952,312 | 9,250,723 | 9,250,723 | 8,952,312 | 9,263,157 | 8,952,312 | 9,250,723 |
| | | | $41.45 | $41.45 | $108,919,800 | 9,250,723 | 8,355,492 | 9,250,723 | 8,939,879 | 9,250,723 | 8,952,312 | 9,250,723 | 9,250,723 | 8,952,312 | 9,263,157 | 8,952,312 | 9,250,723 |
| | | | $41.45 | $41.45 | $108,919,800 | 9,250,723 | 8,355,492 | 9,250,723 | 8,939,879 | 9,250,723 | 8,952,312 | 9,250,723 | 9,250,723 | 8,952,312 | 9,263,157 | 8,952,312 | 9,250,723 |
| | | | $41.45 | $41.45 | $108,919,800 | 9,250,723 | 8,355,492 | 9,250,723 | 8,939,879 | 9,250,723 | 8,952,312 | 9,250,723 | 9,250,723 | 8,952,312 | 9,263,157 | 8,952,312 | 9,250,723 |
| | | | $41.45 | $41.45 | $108,919,800 | 9,250,723 | 8,355,492 | 9,250,723 | 8,939,879 | 9,250,723 | 8,952,312 | 9,250,723 | 9,250,723 | 8,952,312 | 9,263,157 | 8,952,312 | 9,250,723 |
| Transmission | | 2004 | | $1.70 | $4,475,000 | | | | | | | | | | | | |
| | | 2005 | | $1.70 | $4,475,000 | | | | | | | | | | | | |
| | | 2006 | | $1.70 | $4,475,000 | | | | | | | | | | | | |
| | | 2007 | | $1.74 | $4,564,000 | | | | | | | | | | | | |
| | | 2008 | | $1.73 | $4,556,000 | | | | | | | | | | | | |
| Mics. | | 2004 | | $2.05 | $5,380,000 | | | | | | | | | | | | |
| | | 2005 | | $2.05 | $5,380,000 | | | | | | | | | | | | |
| | | 2006 | | $2.05 | $5,380,000 | | | | | | | | | | | | |
| | | 2007 | | $2.05 | $5,384,000 | | | | | | | | | | | | |
| | | 2008 | | $2.05 | $5,396,000 | | | | | | | | | | | | |
| Total Cost | | 2004 | | $45.20 | $118,774,800 | | | | | | | | | | | | |
| | | 2005 | | $45.20 | $118,774,800 | | | | | | | | | | | | |
| | | 2006 | | $45.20 | $118,774,800 | | | | | | | | | | | | |
| | | 2007 | | $45.23 | $118,867,800 | | | | | | | | | | | | |
| | | 2008 | | $45.23 | $118,871,800 | | | | | | | | | | | | |
| Net Increase (Decrease) | | 2004 | | -$8.35 | -$21,945,138 | | | | | | | | | | | | |
| | | 2005 | | -$3.00 | -$7,873,145 | | | | | | | | | | | | |
| | | 2006 | | -$0.59 | -$1,540,747 | | | | | | | | | | | | |
| | | 2007 | | -$0.55 | -$1,447,747 | | | | | | | | | | | | |
| | | 2008 | | -$0.55 | -$1,443,747 | | | | | | | | | | | | |
| Levelized Increase (Decrease) | | | | -$2.88 | -$7,577,498 | | | | | | | | | | | | |

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**Rathdrum CCCT**
**Power Cost Impact**
**2004 - 2009**

| | | | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 4912 | 416 | 384 | 432 | 400 | 416 | 416 | 400 | 432 | 400 | 416 | 400 | 400 |
| | | | 3848 | 328 | 288 | 312 | 319 | 328 | 304 | 344 | 312 | 320 | 329 | 320 | 344 |
| | | | 8760 | 744 | 672 | 744 | 719 | 744 | 720 | 744 | 744 | 720 | 745 | 720 | 744 |
| | | | 2,518,376 | | | | | | | | | | | | |
| Generation (LM 6000s only) | 2004 | | 1,519,561 | 138,650 | 125,184 | 138,663 | 123,795 | 103,152 | 83,838 | 130,325 | 129,637 | 127,521 | 136,809 | 137,146 | 144,840 |
| Generation | 2005 | | 2,437,629 | 311,947 | 191,651 | 204,798 | 204,372 | 177,399 | 124,384 | 186,823 | 192,847 | 188,505 | 199,976 | 216,728 | 238,199 |
| Generation | 2006 | | 2,500,378 | 310,228 | 206,143 | 213,134 | 204,295 | 191,849 | 128,805 | 190,678 | 190,502 | 184,938 | 212,213 | 223,516 | 244,079 |
| Generation | 2007 | | 2,549,435 | 306,888 | 209,734 | 223,106 | 216,452 | 198,982 | 133,989 | 194,857 | 187,489 | 189,197 | 212,583 | 226,126 | 250,033 |
| Generation | 2008 | | 2,554,967 | 298,287 | 210,486 | 218,475 | 208,134 | 227,788 | 141,904 | 183,907 | 186,874 | 185,518 | 213,598 | 229,393 | 250,603 |
| Generation | 2009 | | 2,574,322 | 301,974 | 210,853 | 219,851 | 212,035 | 224,899 | 131,951 | 181,403 | 194,032 | 192,490 | 217,762 | 239,330 | 247,743 |
| Revenue (LM 6000s only) | 2004 | | $83,286,248 | $11,771,044 | $7,270,219 | $7,127,467 | $4,546,542 | $3,578,875 | $4,310,585 | $8,038,713 | $9,353,942 | $8,444,963 | $6,880,806 | $5,796,974 | $6,166,117 |
| Revenue | 2005 | | $119,621,387 | $23,525,022 | $9,751,338 | $9,315,486 | $6,681,344 | $5,339,764 | $5,609,197 | $10,145,823 | $12,559,130 | $10,975,326 | $8,955,873 | $7,975,781 | $8,787,302 |
| Revenue | 2006 | | $115,240,090 | $22,233,218 | $9,728,226 | $9,098,664 | $6,314,030 | $5,512,536 | $5,498,693 | $9,843,839 | $11,771,800 | $10,272,910 | $8,846,878 | $7,697,528 | $8,421,767 |
| Revenue | 2007 | | $117,014,753 | $22,366,876 | $9,816,258 | $9,475,696 | $6,691,750 | $5,615,236 | $5,685,410 | $10,020,339 | $11,571,749 | $10,343,716 | $8,899,743 | $7,888,300 | $8,639,680 |
| Revenue | 2008 | | $117,014,060 | $21,782,051 | $10,039,018 | $9,300,914 | $6,459,629 | $6,415,346 | $5,919,872 | $9,660,883 | $11,549,400 | $10,396,670 | $8,963,470 | $7,807,127 | $8,719,679 |
| Revenue | 2009 | | $117,665,070 | $21,964,831 | $9,902,925 | $9,253,042 | $6,586,120 | $6,243,091 | $5,581,789 | $9,554,766 | $11,904,184 | $10,625,380 | $9,178,301 | $8,172,632 | $8,698,009 |
| | | $/MWh | $/Year | | | | | | | | | | | | |
| Fuel Cost (LM 6000 only) | $3.45 | $32.65 | $49,620,122 | 4,527,499 | 4,087,803 | 4,527,936 | 4,042,446 | 3,368,364 | 2,737,667 | 4,255,655 | 4,233,206 | 4,164,096 | 4,467,395 | 4,478,413 | 4,729,642 |
| Fuel Cost | $3.45 | $21.60 | $52,662,289 | 6,739,265 | 4,140,416 | 4,424,436 | 4,415,237 | 3,832,512 | 2,687,179 | 4,036,108 | 4,166,239 | 4,072,443 | 4,320,262 | 4,682,159 | 5,146,034 |
| Fuel Cost | $3.45 | $21.60 | $54,017,918 | 6,702,126 | 4,453,493 | 4,604,534 | 4,413,564 | 4,144,687 | 2,782,680 | 4,119,380 | 4,115,582 | 3,995,376 | 4,584,633 | 4,828,815 | 5,273,050 |
| Fuel Cost | $3.45 | $21.60 | $55,077,730 | 6,629,980 | 4,531,062 | 4,819,964 | 4,676,199 | 4,298,776 | 2,894,683 | 4,209,660 | 4,050,498 | 4,087,397 | 4,592,622 | 4,885,210 | 5,401,679 |
| Fuel Cost | $3.45 | $21.60 | $55,197,254 | 6,444,160 | 4,547,323 | 4,719,919 | 4,496,504 | 4,921,109 | 3,065,669 | 3,973,108 | 4,037,205 | 4,007,921 | 4,614,550 | 4,955,781 | 5,414,004 |
| Fuel Cost | $3.45 | $21.60 | $55,615,399 | 6,523,807 | 4,555,249 | 4,749,643 | 4,580,781 | 4,858,696 | 2,850,645 | 3,919,010 | 4,191,846 | 4,158,541 | 4,704,515 | 5,170,457 | 5,352,209 |
| O&M (LM 600s only) | 2004 | $6.21 | $9,438,371 | | | | | | | | | | | | |
| O&M | 2005 | $7.60 | $18,530,986 | 12,657 | $5,874 | | | | | | | | | | |
| O&M | 2006 | $7.52 | $18,798,202 | 12,723 | $6,075 | | | | | | | | | | |
| O&M | 2007 | $7.46 | $19,010,189 | 12,794 | $6,216 | | | | | | | | | | |
| O&M | 2008 | $7.55 | $19,293,989 | 12,870 | $6,424 | | | | | | | | | | |
| O&M | 2009 | $7.59 | $19,547,205 | 12,950 | $6,597 | | | | | | | | | | |
| Fixed Costs (LM 6000s only) | 2004 | $18.40 | $27,959,876 | | | | | | | | | | | | |
| Fixed Costs | 2005 | $16.99 | $41,426,867 | | | | | | | | | | | | |
| Fixed Costs | 2006 | $19.20 | $48,016,061 | | | | | | | | | | | | |
| Fixed Costs | 2007 | $18.28 | $46,613,104 | | | | | | | | | | | | |
| Fixed Costs | 2008 | $17.72 | $45,262,598 | | | | | | | | | | | | |
| Fixed Costs | 2009 | $17.06 | $43,916,416 | | | | | | | | | | | | |
| Total Cost (LM 6000s only) | 2004 | $57.27 | $87,018,369 | | | | | | | | | | | | |
| Total Cost | 2005 | $46.20 | $112,620,141 | | | | | | | | | | | | |
| Total Cost | 2006 | $48.33 | $120,832,182 | | | | | | | | | | | | |
| Total Cost | 2007 | $47.34 | $120,701,023 | | | | | | | | | | | | |
| Total Cost | 2008 | $46.87 | $119,753,840 | | | | | | | | | | | | |
| Total Cost | 2009 | $46.26 | $119,079,021 | | | | | | | | | | | | |
| Net Increase (LM 6000s only) | 2004 | $2.46 | $3,732,121 | | | | | | | | | | | | |
| Net Increase | 2005 | -$2.87 | -$7,001,246 | | | | | | | | | | | | |
| Net Increase | 2006 | $2.24 | $5,592,092 | | | | | | | | | | | | |
| Net Increase | 2007 | $1.45 | $3,686,270 | | | | | | | | | | | | |
| Net Increase | 2008 | $1.07 | $2,739,780 | | | | | | | | | | | | |
| Net Increase | 2009 | $0.55 | $1,413,950 | | | | | | | | | | | | |
| Levelized Increase (Decrease) 2004-09 | | $0.81 | $1,594,409 | | | | | | | | | | | | |

CONFIDENTIAL

**Coyote 2**
**Power Cost Impact**
**2002 - 2007**

| | | | | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 4912 | 416 | 384 | 432 | 400 | 416 | 416 | 400 | 432 | 400 | 416 | 400 | 400 |
| | | | | 3848 | 328 | 288 | 312 | 319 | 328 | 304 | 344 | 312 | 320 | 329 | 320 | 344 |
| | | | | 8760 | 744 | 672 | 744 | 719 | 744 | 720 | 744 | 744 | 720 | 745 | 720 | 744 |
| | | | | 1,042,818 | | | | | | | | | | | | |
| Generation 2002 only | HLH | | | 603,416 | | | | | | | 98,195 | 92,624 | 98,091 | 98,293 | 105,604 | 110,609 |
| Generation 2002 only | LLH | | | 439,402 | | | | | | | 69,153 | 74,837 | 68,270 | 80,002 | 72,278 | 74,862 |
| Generation 2003 - 2007 | HLH | | | 1,181,506 | 108,640 | 95,863 | 102,563 | 98,846 | 97,013 | 75,165 | 98,195 | 92,624 | 98,091 | 98,293 | 105,604 | 110,609 |
| Generation 2003 - 2007 | LLH | | | 839,147 | 77,781 | 75,156 | 75,237 | 72,397 | 55,009 | 44,166 | 69,153 | 74,837 | 68,270 | 80,002 | 72,278 | 74,862 |
| | | | | 2,020,653 | | | | | | | | | | | | |
| Revenue | 2002 | | | $81,482,031 | $0 | $0 | $0 | $0 | $0 | $0 | $14,552,887 | $16,975,389 | $15,509,123 | $12,593,099 | $10,655,014 | $11,196,518 |
| Revenue | 2003 | | | $129,159,757 | $18,451,726 | $11,465,069 | $10,712,594 | $7,350,572 | $5,985,387 | $7,111,044 | $12,162,188 | $14,171,767 | $12,966,220 | $10,520,602 | $8,904,677 | $9,357,913 |
| Revenue | 2004 | | | $109,785,794 | $15,683,967 | $9,745,308 | $9,105,705 | $6,247,987 | $5,087,579 | $6,044,387 | $10,337,859 | $12,046,002 | $11,021,287 | $8,942,512 | $7,568,975 | $7,954,226 |
| Revenue | 2005 | | | $98,807,214 | $14,115,570 | $8,770,777 | $8,195,134 | $5,623,188 | $4,578,821 | $5,439,949 | $9,304,074 | $10,841,402 | $9,919,158 | $8,048,261 | $6,812,078 | $7,158,803 |
| Revenue | 2006 | | | $93,866,854 | $13,409,792 | $8,332,239 | $7,785,377 | $5,342,028 | $4,349,880 | $5,167,951 | $8,838,870 | $10,299,332 | $9,423,200 | $7,645,848 | $6,471,474 | $6,800,863 |
| Revenue | 2007 | | | $93,866,854 | $13,409,792 | $8,332,239 | $7,785,377 | $5,342,028 | $4,349,880 | $5,167,951 | $8,838,870 | $10,299,332 | $9,423,200 | $7,645,848 | $6,471,474 | $6,800,863 |
| | | | $/MWh | $/Year | | | | | | | | | | | | |
| Fuel Cost | | $3.45 | $24.46 | $25,507,855 | 0 | 0 | 0 | 0 | 0 | 0 | 4,093,404 | 4,096,197 | 4,069,281 | 4,361,182 | 4,351,090 | 4,536,701 |
| | | $3.45 | $24.46 | $49,426,185 | 4,559,934 | 4,183,193 | 4,349,079 | 4,188,687 | 3,718,537 | 2,918,901 | 4,093,404 | 4,096,197 | 4,069,281 | 4,361,182 | 4,351,090 | 4,536,701 |
| | | $3.45 | $24.46 | $49,426,185 | 4,559,934 | 4,183,193 | 4,349,079 | 4,188,687 | 3,718,537 | 2,918,901 | 4,093,404 | 4,096,197 | 4,069,281 | 4,361,182 | 4,351,090 | 4,536,701 |
| | | $3.45 | $24.46 | $49,426,185 | 4,559,934 | 4,183,193 | 4,349,079 | 4,188,687 | 3,718,537 | 2,918,901 | 4,093,404 | 4,096,197 | 4,069,281 | 4,361,182 | 4,351,090 | 4,536,701 |
| | | $3.45 | $24.46 | $49,426,185 | 4,559,934 | 4,183,193 | 4,349,079 | 4,188,687 | 3,718,537 | 2,918,901 | 4,093,404 | 4,096,197 | 4,069,281 | 4,361,182 | 4,351,090 | 4,536,701 |
| | | $3.45 | $24.46 | $49,426,185 | 4,559,934 | 4,183,193 | 4,349,079 | 4,188,687 | 3,718,537 | 2,918,901 | 4,093,404 | 4,096,197 | 4,069,281 | 4,361,182 | 4,351,090 | 4,536,701 |
| O&M | 2002 | | $10.09 | $10,521,000 | | | | | | | | | | | | |
| | 2003 | | $10.52 | $21,252,430 | | | | | | | | | | | | |
| | 2004 | | $10.64 | $21,509,298 | | | | | | | | | | | | |
| | 2005 | | $10.77 | $21,770,232 | | | | | | | | | | | | |
| | 2006 | | $10.90 | $22,032,115 | | | | | | | | | | | | |
| | 2007 | | $11.08 | $22,392,483 | | | | | | | | | | | | |
| Fixed Costs | 2002 | | $15.95 | $16,632,000 | | | | | | | | | | | | |
| | 2003 | | $15.90 | $32,135,291 | | | | | | | | | | | | |
| | 2004 | | $15.29 | $30,905,704 | | | | | | | | | | | | |
| | 2005 | | $14.76 | $29,815,652 | | | | | | | | | | | | |
| | 2006 | | $14.33 | $28,949,848 | | | | | | | | | | | | |
| | 2007 | | $13.92 | $28,126,901 | | | | | | | | | | | | |
| Total Cost | 2002 | | $50.50 | $52,660,855 | | | | | | | | | | | | |
| | 2003 | | $50.88 | $102,813,906 | | | | | | | | | | | | |
| | 2004 | | $50.40 | $101,841,187 | | | | | | | | | | | | |
| | 2005 | | $49.99 | $101,012,070 | | | | | | | | | | | | |
| | 2006 | | $49.69 | $100,408,148 | | | | | | | | | | | | |
| | 2007 | | $49.46 | $99,945,569 | | | | | | | | | | | | |
| Net Increase (Decrease) | 2002 | | -$27.64 | -$28,821,176 | | | | | | | | | | | | |
| | 2003 | | -$13.04 | -$26,345,851 | | | | | | | | | | | | |
| | 2004 | | -$3.93 | -$7,944,607 | | | | | | | | | | | | |
| | 2005 | | $1.09 | $2,204,855 | | | | | | | | | | | | |
| | 2006 | | $3.24 | $6,541,295 | | | | | | | | | | | | |
| | 2007 | | $3.01 | $6,078,715 | | | | | | | | | | | | |
| Levelized Increase (Decrease) 2002-07 | | | -$7.53 | -$9,829,663 | | | | | | | | | | | | |

BEFORE THE

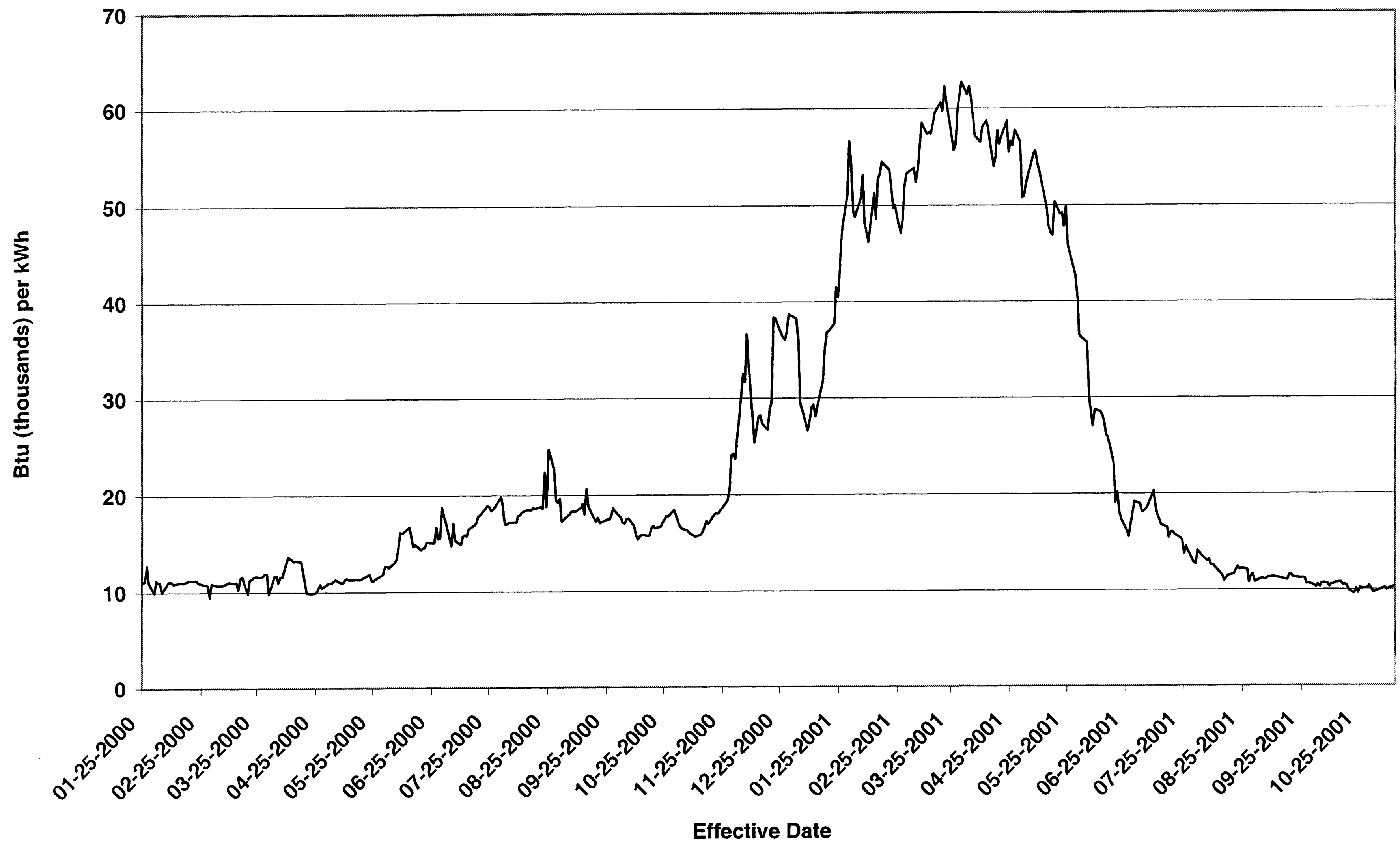
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-11)

# One-Year Forward Implied Heat Rate

**Mid-C Electric Contract to NYMEX Henry Hub Natural Gas: 1-25-00 through 11-12-01**




Spark Spread_1Yr Forward Strips.xls, 11-27-2001, bjs

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-12)

## Avista Utilities
## Summary of Forward Natural Gas Fixed Priced Purchases Compared to Electric Market Prices
## April 2000 through October 2001

| Transaction Date | Delivery Period | Transaction Volume Dth/day | Gas Fixed Price ($/Dth) | Plant | Variable Generation Cost ($/MWh) | Mid-C HLH Price ($/MWh) | Mid-C LLH Price ($/MWh) | HLH (Benefit/ MWh) | LLH (Benefit/ MWh) |
|---|---|---|---|---|---|---|---|---|---|
| 04-12-2000 | Aug-00 | 5,000 | $2.82 | Rathdrum | $33.45 | $50.25 | | $16.80 | |
| 05-01-2000 | Aug-00 | 5,000 | $3.03 | Rathdrum | $35.87 | $56.13 | | $20.27 | |
| 05-01-2000 | Sep-00 | 5,000 | $3.10 | Rathdrum | $36.67 | $56.13 | | $19.46 | |
| 05-05-2000 | Sep-00 | 5,000 | $2.885 | Rathdrum | $34.20 | $57.00 | | $22.80 | |
| 05-10-2000 | Jun-00 | 5,000 | $2.81 | Rathdrum | $33.34 | $37.30 | | $3.97 | |
| 05-17-2000 | Jun-00 | 5,000 | $3.10 | Rathdrum | $36.67 | $49.00 | | $12.33 | |
| 06-01-2000 | Jul-00 | 10,000 | $3.85 | Rathdrum | $45.30 | $75.08 | | $29.79 | |
| 06-01-2000 | Jul-00 | 4,500 | $3.77 | Rathdrum | $44.38 | $75.08 | | $30.71 | |
| 06-12-2000 | Oct-00 | 5,000 | $4.10 | Rathdrum | $48.17 | $81.00 | | $32.83 | |
| 06-13-2000 | Aug-00 | 10,000 | $3.80 | Rathdrum | $44.72 | $139.50 | | $94.78 | |
| 06-23-2000 | Oct-00 | 5,000 | $4.50 | Rathdrum | $52.77 | $73.30 | | $20.53 | |
| 06-23-2000 | Nov-00 | 5,000 | $4.50 | Rathdrum | $52.77 | $73.30 | | $20.53 | |
| 06-23-2000 | Dec-00 | 5,000 | $4.50 | Rathdrum | $52.77 | $73.30 | | $20.53 | |
| 06-30-2000 | Nov-00 | 5,000 | $4.45 | Rathdrum | $52.20 | $82.00 | | $29.81 | |
| 06-30-2000 | Dec-00 | 5,000 | $4.45 | Rathdrum | $52.20 | $83.00 | | $30.81 | |
| 06-30-2000 | Jan-01 | 5,000 | $4.45 | Rathdrum | $52.20 | $57.00 | | $4.80 | |
| 06-30-2000 | Feb-01 | 5,000 | $4.45 | Rathdrum | $52.20 | $54.00 | | $1.80 | |
| 06-30-2000 | Mar-01 | 5,000 | $4.45 | Rathdrum | $52.20 | $54.00 | | $1.80 | |
| 07-18-2000 | Jan-01 | 5,000 | $4.05 | Rathdrum | $47.60 | $58.00 | | $10.41 | |
| 07-18-2000 | Feb-01 | 5,000 | $4.05 | Rathdrum | $47.60 | $58.00 | | $10.41 | |
| 07-18-2000 | Mar-01 | 5,000 | $4.05 | Rathdrum | $47.60 | $58.00 | | $10.41 | |
| 08-29-2000 | Sep-00 | 25,000 | $4.03 | Rathdrum | $47.37 | $134.00 | $80.00 | $86.64 | $32.64 |
| 08-29-2000 | Oct-00 | 25,000 | $4.03 | Rathdrum | $47.37 | $136.25 | $80.00 | $88.89 | $32.64 |
| 08-30-2000 | Nov-00 | 5,000 | $5.04 | Rathdrum | $58.98 | $96.00 | | $37.02 | |
| 08-30-2000 | Dec-00 | 10,000 | $5.22 | Rathdrum | $61.05 | $96.00 | | $34.95 | |
| 08-30-2000 | Jan-01 | 10,000 | $5.12 | Rathdrum | $59.90 | $90.00 | | $30.10 | |
| 09-12-2000 | Nov-00 | 5,000 | $5.45 | Rathdrum | $63.70 | $118.00 | | $54.31 | |
| 09-12-2000 | Dec-00 | 5,000 | $5.45 | Rathdrum | $63.70 | $122.00 | $65.00 | $58.31 | $1.30 |
| 09-12-2000 | Jan-01 | 5,000 | $5.45 | Rathdrum | $63.70 | $109.00 | $60.00 | $45.31 | ($3.70) |
| 09-12-2000 | Feb-01 | 5,000 | $5.45 | Rathdrum | $63.70 | $100.00 | | $36.31 | |

Note: HLH = Heavy Load Hour; LLH = Light Load Hour

LLH Margin is shown when enough natural gas is purchased to run some LLH in addition to all HLH.

11-28-2001

## Avista Utilities

**Summary of Forward Natural Gas Fixed Priced Purchases Compared to Electric Market Prices**

**April 2000 through October 2001**

| Transaction Date | Delivery Period | Transaction Volume Dth/day | Gas Fixed Price ($/Dth) | Plant | Variable Generation Cost ($/MWh) | Mid-C HLH Price ($/MWh) | Mid-C LLH Price ($/MWh) | HLH (Benefit/ MWh) | LLH (Benefit/ MWh) |
|---|---|---|---|---|---|---|---|---|---|
| 09-15-2000 | Nov-00 | 10,000 | $5.37 | Rathdrum | $62.78 | $118.00 | $70.00 | $55.23 | $7.22 |
| 09-15-2000 | Dec-00 | 10,000 | $5.37 | Rathdrum | $62.78 | $120.00 | $65.00 | $57.23 | $2.22 |
| 09-15-2000 | Jan-01 | 10,000 | $5.37 | Rathdrum | $62.78 | $108.00 | $60.00 | $45.23 | ($2.78) |
| 09-15-2000 | Feb-01 | 10,000 | $5.37 | Rathdrum | $62.78 | $94.00 | $60.00 | $31.23 | ($2.78) |
| 09-15-2000 | Mar-01 | 10,000 | $5.37 | Rathdrum | $62.78 | $92.00 | $60.00 | $29.23 | ($2.78) |
| 09-15-2000 | Apr-01 | 10,000 | $5.37 | Rathdrum | $62.78 | $66.00 | | $3.22 | |
| | | | | | | | | | |
| 09-15-2000 | Oct-00 | 5,000 | $5.66 | Rathdrum | $66.11 | $137.25 | $80.00 | $71.14 | $13.89 |
| 09-15-2000 | Nov-00 | 5,000 | $5.66 | Rathdrum | $66.11 | $118.00 | $70.00 | $51.89 | $3.89 |
| | | | | | | | | | |
| 09-15-2000 | Nov-00 | 5,000 | $5.63 | Rathdrum | $65.77 | $118.00 | $70.00 | $52.24 | $4.24 |
| 09-15-2000 | Dec-00 | 5,000 | $5.63 | Rathdrum | $65.77 | $120.00 | $65.00 | $54.24 | ($0.77) |
| 09-15-2000 | Jan-01 | 5,000 | $5.63 | Rathdrum | $65.77 | $108.00 | $60.00 | $42.24 | ($5.77) |
| | | | | | | | | | |
| 09-15-2000 | Jun-01 | 10,000 | $4.43 | Rathdrum | $51.97 | $88.00 | | $36.04 | |
| 09-15-2000 | Jul-01 | 10,000 | $4.43 | Rathdrum | $51.97 | $152.00 | | $100.04 | |
| 09-15-2000 | Aug-01 | 10,000 | $4.43 | Rathdrum | $51.97 | $162.00 | | $110.04 | |
| 09-15-2000 | Sep-01 | 10,000 | $4.43 | Rathdrum | $51.97 | $157.00 | | $105.04 | |
| 09-15-2000 | Oct-01 | 10,000 | $4.43 | Rathdrum | $51.97 | $90.00 | | $38.04 | |
| 09-15-2000 | Nov-01 | 10,000 | $4.43 | Rathdrum | $51.97 | $80.00 | | $28.04 | |
| 09-15-2000 | Dec-01 | 10,000 | $4.43 | Rathdrum | $51.97 | $80.00 | | $28.04 | |
| | | | | | | | | | |
| 09-15-2000 | Jul-01 | 30,000 | $4.64 | Rathdrum | $54.38 | $152.00 | $50.00 | $97.62 | ($4.38) |
| 09-15-2000 | Aug-01 | 30,000 | $4.64 | Rathdrum | $54.38 | $162.00 | $50.00 | $107.62 | ($4.38) |
| 09-15-2000 | Sep-01 | 30,000 | $4.64 | Rathdrum | $54.38 | $157.00 | $50.00 | $102.62 | ($4.38) |
| 09-15-2000 | Oct-01 | 30,000 | $4.64 | Rathdrum | $54.38 | $90.00 | $50.00 | $35.62 | ($4.38) |
| 09-15-2000 | Nov-01 | 30,000 | $4.64 | Rathdrum | $54.38 | $80.00 | $50.00 | $25.62 | ($4.38) |
| 09-15-2000 | Dec-01 | 30,000 | $4.64 | Rathdrum | $54.38 | $80.00 | $50.00 | $25.62 | ($4.38) |
| | | | | | | | | | |
| 11-29-2000 | Dec-00 | 4,000 | $15.50 | Rathdrum | $187.02 | | $215.00 | | $27.98 |
| | | | | | | | | | |
| 12-28-2000 | Jan-01 | 4,000 | $12.75 | Rathdrum | $154.02 | | $500.00 | | $345.98 |
| | | | | | | | | | |
| 01-26-2001 | Apr-01 | 10,000 | $6.33 | Rathdrum | $76.98 | $377.50 | | $300.52 | |
| | | | | | | | | | |
| 01-29-2001 | Apr-01 | 5,000 | $5.90 | Rathdrum | $71.82 | $377.50 | $150.00 | $305.68 | $78.18 |
| | | | | | | | | | |
| 02-09-2001 | Aug-01 | 5,000 | $6.07 | NECT | $83.91 | $345.00 | $278.00 | $261.09 | |
| 02-09-2001 | Sep-01 | 5,000 | $6.07 | NECT | $83.91 | $333.00 | $266.00 | $249.09 | |
| 02-09-2001 | Oct-01 | 5,000 | $6.07 | NECT | $83.91 | $353.00 | $298.00 | $269.09 | |
| | | | | | | | | | |
| 02-12-2001 | Aug-01 | 10,000 | $5.87 | NECT | $81.31 | $408.00 | $341.00 | $326.69 | $259.69 |
| 02-12-2001 | Sep-01 | 10,000 | $5.87 | NECT | $81.31 | $394.00 | $327.00 | $312.69 | $245.69 |
| 02-12-2001 | Oct-01 | 10,000 | $5.87 | NECT | $81.31 | $372.00 | $317.00 | $290.69 | $235.69 |
| | | | | | | | | | |
| 02-12-2001 | Nov-01 | 10,000 | $8.97 | NECT | $121.61 | $304.00 | $249.00 | $182.39 | |
| 02-12-2001 | Dec-01 | 10,000 | $8.97 | NECT | $121.61 | $359.00 | $304.00 | $237.39 | |

Note: HLH = Heavy Load Hour; LLH = Light Load Hour

LLH Margin is shown when enough natural gas is purchased to run some LLH in addition to all HLH.

11-28-2001

## Avista Utilities
## Summary of Forward Natural Gas Fixed Priced Purchases Compared to Electric Market Prices
## April 2000 through October 2001

| Transaction Date | Delivery Period | Transaction Volume Dth/day | Gas Fixed Price ($/Dth) | Plant | Variable Generation Cost ($/MWh) | Mid-C HLH Price ($/MWh) | Mid-C LLH Price ($/MWh) | HLH (Benefit/ MWh) | LLH (Benefit/ MWh) |
|---|---|---|---|---|---|---|---|---|---|
| 02-26-2001 | Mar-01 | 5,000 | $5.49 | NECT | $76.37 | $227.50 | $200.20 | $151.13 | |
| 02-26-2001 | Apr-01 | 5,000 | $5.49 | NECT | $76.37 | $235.00 | $206.80 | $158.63 | |
| 03-01-2001 | Mar-01 | 10,000 | $5.60 | NECT | $77.80 | $300.00 | $264.00 | $222.20 | |
| 03-01-2001 | Apr-01 | 10,000 | $5.45 | NECT | $75.85 | $291.00 | $256.08 | $215.15 | |
| 03-01-2001 | May-01 | 10,000 | $5.45 | NECT | $75.85 | $272.50 | $239.80 | $196.65 | |
| 03-12-2001 | Apr-01 | 10,000 | $5.28 | Rathdrum | $64.38 | $282.00 | $248.16 | $217.62 | $183.78 |
| 03-12-2001 | May-01 | 10,000 | $5.28 | Rathdrum | $64.38 | $273.00 | $240.24 | $208.62 | $175.86 |
| 03-12-2001 | Jun-01 | 10,000 | $5.28 | Rathdrum | $64.38 | $292.50 | $257.40 | $228.12 | $193.02 |
| 04-10-2001 | June-02 - Oct-03 | 10,000 | $6.56 | CSII | $46.06 | $ 126.75 | $ 105.38 | $80.70 | $59.33 |
| 04-11-2001 | Nov-01 - Dec-01 | 10,000 | $6.90 | NECT | $94.73 | $ 309.00 | $ 271.92 | $214.27 | $177.19 |
| 04-11-2001 | Nov-01 - May-02 | 10,000 | $6.90 | Rathdrum | $83.85 | $ 230.86 | $ 212.53 | $161.78 | $140.51 |
| 04-11-2001 | Jan-02 - May-02 | 10,000 | $6.90 | Boulder Pk | $67.64 | $ 199.60 | $ 188.78 | $131.96 | $121.14 |
| 04-11-2001 | June-02 - Oct-04 | 10,000 | $6.90 | CSII | $48.44 | $ 108.89 | $ 85.08 | $60.45 | $36.64 |
| 05-02-2001 | Nov-01 - May-02 | 10,000 | $6.00 | NECT | $83.00 | $ 254.00 | $ 223.52 | $171.00 | $140.52 |
| 05-02-2001 | Nov-01 - May-02 | 10,000 | $6.00 | Rathdrum | $73.02 | $ 187.86 | $ 147.45 | $104.98 | $66.84 |
| 05-02-2001 | Jan-02 - May-02 | 10,000 | $6.00 | Boulder Pk | $59.45 | $ 161.40 | $ 117.02 | $101.95 | $57.57 |
| 05-02-2001 | June-02 - Oct-04 | 10,000 | $6.00 | CSII | $42.16 | $ 84.78 | $ 61.46 | $42.62 | $19.30 |
| 05-10-2001 | June-02 - Oct-03 | 10,000 | $5.41 | CSII | $38.06 | $ 100.99 | $ 79.27 | $62.93 | $41.21 |
| 10-25-2001 | Aug-02 | 5,000 | $3.07 | Rathdrum | $37.86 | $ 49.00 | $ 31.61 | $11.14 | |
| 10-25-2001 | Sep-02 | 5,000 | $3.07 | Rathdrum | $37.86 | $ 45.00 | $ 29.03 | $7.14 | |

Note: HLH = Heavy Load Hour; LLH = Light Load Hour

LLH Margin is shown when enough natural gas is purchased to run some LLH in addition to all HLH.

11-28-2001

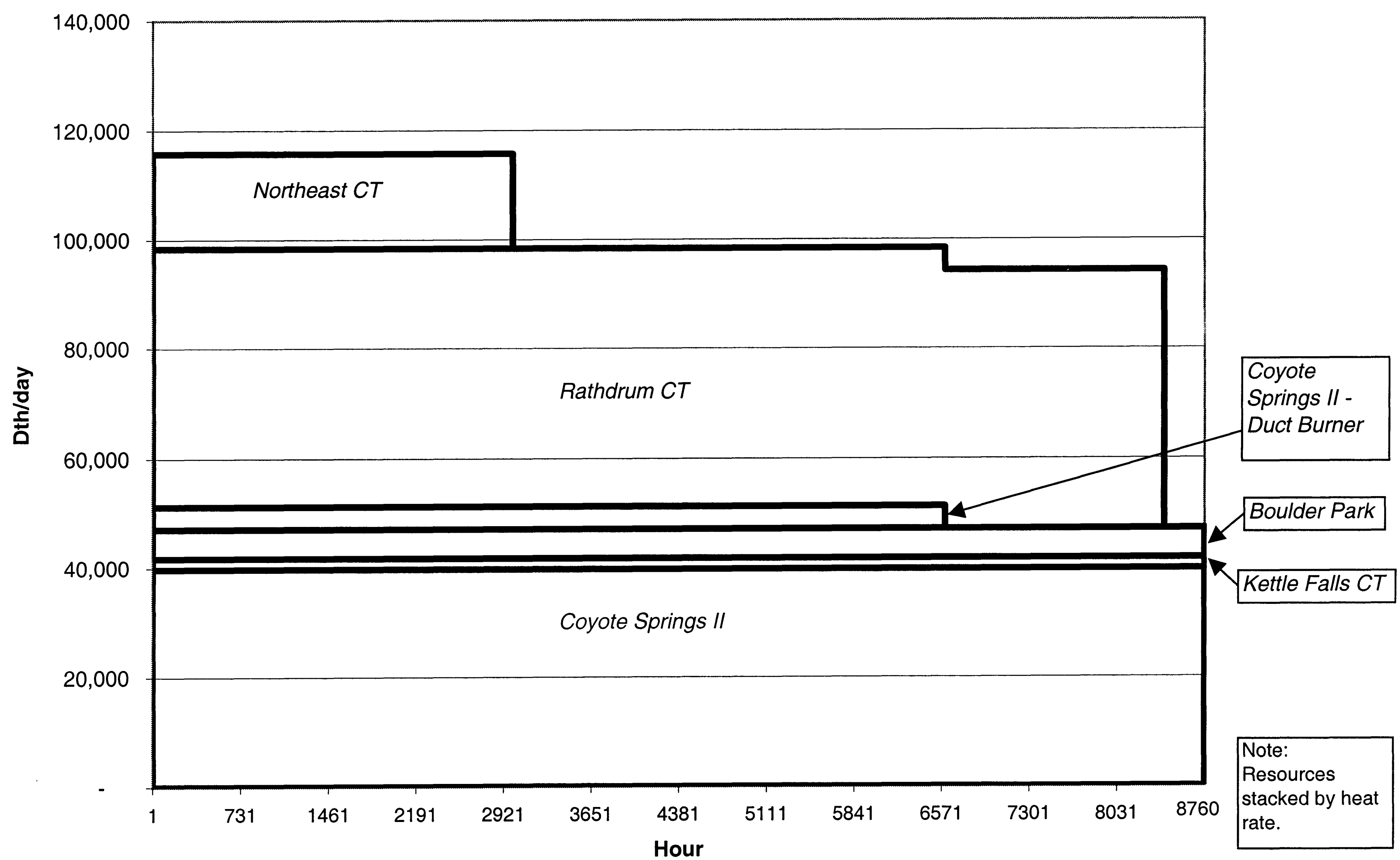
BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-13)

## Average Maximum Daily Natural Gas Consumption By Generation Project For A One Year Period




11-26-2001

# Avista Corporation
## Natural Gas for Thermal Generation

**Maximum Daily Natural Gas Consumption**

| | NECT (dth/day) | Rathdrum (dth/day) | Boulder Park (dth/day) | KFCT (dth/day) | CSII (dth/day) | CSII Duct (dth/day) | Total (dth/day) |
|---|---|---|---|---|---|---|---|
| Jan | 18,720 | 49,630 | 5,358 | 1,995 | 41,844 | 4,357 | 121,904 |
| Feb | 18,408 | 49,050 | 5,358 | 1,995 | 41,194 | 4,290 | 120,295 |
| Mar | 17,784 | 48,123 | 5,358 | 1,995 | 40,410 | 4,200 | 117,869 |
| April | 17,472 | 47,137 | 5,358 | 1,995 | 39,675 | 4,133 | 115,771 |
| May | 17,160 | 46,209 | 5,358 | 1,995 | 38,958 | 4,044 | 113,724 |
| June | 17,160 | 45,514 | 5,358 | 1,995 | 38,341 | 3,999 | 112,366 |
| July | 15,600 | 44,586 | 5,358 | 1,995 | 37,707 | 3,932 | 109,178 |
| Aug | 15,600 | 44,702 | 5,358 | 1,995 | 37,807 | 3,932 | 109,394 |
| Sept | 17,160 | 45,688 | 5,358 | 1,995 | 38,508 | 3,999 | 112,707 |
| Oct | 17,472 | 47,021 | 5,358 | 1,995 | 39,642 | 4,133 | 115,621 |
| Nov | 17,784 | 48,645 | 5,358 | 1,995 | 40,960 | 4,267 | 119,009 |
| Dec | 18,720 | 49,456 | 5,358 | 1,995 | 41,728 | 4,334 | 121,591 |
| Annual Ave. Max. Daily Nat. Gas Consumption | 17,420 | 47,147 | 5,358 | 1,995 | 39,731 | 4,135 | 115,786 |
| Annual Ave. Max. Daily Nat. Gas Consumption based on Air Permit Operating Hours | 5,966 | 45,338 | 5,358 | 1,995 | 39,731 | 3,115 | 101,504 |

| | Annual Ave. Daily Natural Gas Requirement (dth/day) | % Of Nat. Gas Hedged for Period 11-1-01 through 12-31-01 | % Of Nat. Gas Hedged for Period 1-1-01 through 5-31-02 | % Of Nat. Gas Hedged for Period 6-1-02 through 10-31-03 | % Of Nat. Gas Hedged for Period 11-1-03 through 10-31-04 |
|---|---|---|---|---|---|
| Coyote Springs II | 42,847 | N.A. | N.A. | 93% | 47% |
| Rathdrum | 45,338 | 44% | 32% | N.A. | N.A. |
| Boulder Park | 5,358 | N.A. | 100% | N.A. | N.A. |

Notes:
1) Period 11-1-01 through 12-31-01; 20,000 Dth/day hedged
2) Period 1-1-02 through 5-31-02; 20,000 Dth/day hedged
3) Period 6-1-02 through 10-31-03; 40,000 Dth/day hedged
4) Period 11-1-03 through 10-31-04; 20,000 Dth/day hedged
5) N.A. means that the plant either is not available or it is not the most economic plant available to use the nat. gas

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-C14)

**CONFIDENTIAL**

Avista Utilities
Gas/Electric Transaction

Date of Transaction: 3/9 ~~3~~ Confirm on 3/13 Reference No. ___

Transaction Details: Purchase/Sale (Circle)

Delivery Period Nov 1, 2001 - Oct 31, 2004

Volume ~~27~~, 658 decatherms/day

Location Malin

Price Malin NGI Monthly Index +$.15

~~Broker~~ Petro Canada

Pan Canadian indicated that market was +$.07-$.09 this year & +$.10-.15 next year

Market Conditions: Needed to get gas to secure bank borrowing. Seemed to be a lack of transport available - Newport not interested in releasing to AOBX had lost out on bid for GTN transport available 11/1/02.

System Position and Reason for Action (Attach Position Report): Petro normally did 1 year deals beginning in Nov & put out for bid in June. ~~[illegible]~~ The value of firm transport caused us to make this offer.

Dispatchability of Product: Petro provides the gas @ AECO with enough to cover fuel to Malin equates to ≈ 28,000 @ Coyo + 28,500 @ RGEN

Transmission Alternatives: May be dropped off @ Kingsgate - RGEN - STAN - COYO or MALIN.

Building Options: ~~PG~~ GTN capacity will be available under open season either ~~$~~ 11/01/03 or 11/01/04.

JRT 10/2/00

# Enron Ca[illegible]ada Corp.
March 9, 2001

CONFIDENTIAL

## AECO / NIT ($CND/GJ)

| | Fixed Price ($CND/GJ) BID | Fixed Price OFFER | Basis ($US /MMBtu) BID | Basis OFFER | Aeco/Empress Transport BID | Transport OFFER |
|---|---|---|---|---|---|---|
| Cash (Physical) | 7.365 | 7.375 | | | | |
| ROM | 7.335 | 7.345 | | | - | 0.015 |
| Apr-01 (Physical) | 7.360 | 7.370 | (0.268) | (0.248) | - | 0.025 |
| Apr-01 to Oct-01 | 7.499 | 7.519 | (0.275) | (0.255) | (0.010) | 0.010 |
| Nov-01 to Mar-02 | 7.708 | 7.728 | (0.205) | (0.185) | 0.140 | 0.160 |
| Apr-02 to Oct-02 | 6.318 | 6.338 | (0.375) | (0.355) | 0.140 | 0.160 |
| Nov-01 to Oct-02 | 6.906 | 6.926 | (0.300) | (0.280) | 0.140 | 0.160 |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| Derek Davies | 974-6793 | Rob Milnthorp | 974-6714 |
| John Disturnal | 974-6772 | Cyntia Di Stefano | 974-6750 |
| Dean Drozdiak | 974-6751 | Grant Oh | 974-6778 |


## F/X, Henry Hub, NYMEX, ROCKIES

| | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE | ROCKIES ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|
| Cash (Physical) | 1.547 | 5.245 | | 4.935 | 4.955 | | |
| ROM | | 5.190 | | 4.750 | 4.770 | | |
| Apr-01 | | | 5.285 | 4.830 | 4.850 | (0.455) | (0.435) |
| Apr-01 to Oct-01 | | | 5.393 | 4.703 | 4.723 | (0.690) | (0.670) |
| Nov-01 to Mar-02 | | | 5.471 | 5.156 | 5.176 | (0.315) | (0.295) |
| Apr-02 to Oct-02 | | | 4.694 | 4.164 | 4.184 | (0.530) | (0.510) |
| Nov-01 to Oct-02 | | | 5.020 | 4.580 | 4.600 | (0.440) | (0.420) |

## SAN JUAN ($US/MMBtu) and DAWN ($US/MMBtu)

| | SAN JUAN Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | DAWN Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | | | | | 5.620 | 5.640 | | |
| ROM | 4.780 | 4.800 | | | 5.550 | 5.570 | | |
| Apr-01 | 4.915 | 4.935 | (0.370) | (0.350) | 5.540 | 5.560 | 0.255 | 0.27 |
| Apr-01 to Oct-01 | 5.013 | 5.033 | (0.380) | (0.360) | 5.648 | 5.668 | 0.255 | 0.27 |
| Nov-01 to Mar-02 | 5.276 | 5.296 | (0.195) | (0.175) | 5.836 | 5.856 | 0.365 | 0.38 |
| Apr-02 to Oct-02 | 4.509 | 4.529 | (0.185) | (0.165) | 4.914 | 4.934 | 0.220 | 0.24 |
| Nov-01 to Oct-02 | 4.830 | 4.850 | (0.190) | (0.170) | 5.300 | 5.320 | 0.280 | 0.30 |

## STATION 2 and MALIN ($US/MMBtu)

| | STATION 2 Fixed Price ($C/GJ) BID | Fixed Price OFFER | Basis ($US/MMBtu) BID | Basis OFFER | MALIN Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 7.250 | 7.280 | | | 8.190 | 8.210 | | |
| ROM | 7.235 | 7.265 | | | 7.990 | 8.010 | | |
| Apr-01 | 7.434 | 7.464 | (0.210) | (0.190) | 7.725 | 7.745 | 2.440 | 2.460 |
| Apr-01 to Oct-01 | 7.589 | 7.619 | (0.210) | (0.190) | 7.593 | 7.613 | 2.200 | 2.220 |
| Nov-01 to Mar-02 | 7.981 | 8.011 | (0.015) | 0.005 | 7.361 | 7.381 | 1.890 | 1.910 |
| Apr-02 to Oct-02 | 6.415 | 6.445 | (0.305) | (0.285) | 5.839 | 5.859 | 1.145 | 1.165 |
| Nov-01 to Oct-02 | 7.070 | 7.100 | (0.185) | (0.165) | 6.480 | 6.500 | 1.460 | 1.480 |

## VENTURA ($US/MMBtu) and NIAGARA ($US/MMBtu)

| | VENTURA Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | NIAGARA Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 5.335 | 5.355 | | | 5.680 | 5.700 | | |
| ROM | 5.310 | 5.330 | | | 5.610 | 5.630 | | |
| Apr-01 | 5.325 | 5.345 | 0.040 | 0.060 | 5.590 | 5.610 | 0.305 | 0.325 |
| Apr-01 to Oct-01 | 5.423 | 5.443 | 0.030 | 0.050 | 5.698 | 5.718 | 0.305 | 0.325 |
| Nov-01 to Mar-02 | 5.616 | 5.636 | 0.145 | 0.165 | 6.011 | 6.031 | 0.540 | 0.560 |
| Apr-02 to Oct-02 | 4.714 | 4.734 | 0.020 | 0.040 | 4.939 | 4.959 | 0.245 | 0.265 |
| Nov-01 to Oct-02 | 5.090 | 5.110 | 0.070 | 0.090 | 5.390 | 5.410 | 0.370 | 0.390 |

## SUMAS ($US/MMBtu) and SoCAL ($US/MMBtu)

| | SUMAS Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SoCAL Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 5.090 | 5.110 | | | 12.815 | 12.835 | | |
| ROM | 5.130 | 5.150 | | | 13.620 | 13.640 | | |
| Apr-01 | 5.155 | 5.175 | (0.130) | (0.110) | 9.125 | 9.145 | 3.840 | 3.860 |
| Apr-01 to Oct-01 | 5.288 | 5.308 | (0.105) | (0.085) | 8.678 | 8.698 | 3.285 | 3.305 |
| Nov-01 to Mar-02 | 6.616 | 6.636 | 1.145 | 1.165 | 7.661 | 7.681 | 2.190 | 2.210 |
| Apr-02 to Oct-02 | 4.594 | 4.614 | (0.100) | (0.080) | 6.339 | 6.359 | 1.645 | 1.665 |
| Nov-01 to Oct-02 | 5.440 | 5.460 | 0.420 | 0.440 | 6.895 | 6.915 | 1.875 | 1.895 |

## CHICAGO CITY GATE ($US/MMBtu) and TRANSCO Z6 ($US/MMBtu)

| | CHICAGO CITY GATE Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | TRANSCO Z6 Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 5.470 | 5.490 | | | 5.765 | 5.785 | | |
| ROM | 5.420 | 5.440 | | | 5.760 | 5.780 | | |
| Apr-01 | 5.420 | 5.440 | 0.135 | 0.155 | 5.745 | 5.765 | 0.460 | 0.480 |
| Apr-01 to Oct-01 | 5.528 | 5.548 | 0.135 | 0.155 | 5.898 | 5.918 | 0.505 | 0.525 |
| Nov-01 to Mar-02 | 5.706 | 5.726 | 0.235 | 0.255 | 6.981 | 7.001 | 1.510 | 1.530 |
| Apr-02 to Oct-02 | 4.809 | 4.829 | 0.115 | 0.135 | 5.159 | 5.179 | 0.465 | 0.485 |
| Nov-01 to Oct-02 | 5.185 | 5.205 | 0.165 | 0.185 | 5.920 | 5.940 | 0.900 | 0.920 |

**CONFIDENTIAL**

Avista Utilities
Gas/Electric Transaction

Date of Transaction: 3/22/01 Reference No. ____________

Transaction Details: Purchase / Sale (Circle)

Delivery Period 6/1/02 thru 10/31/03

Volume 20,000 MMBtu/day

Location Coyote

Price NGI Monthly Index Malin + .06 .08

~~Broker~~ Avista Energy

Market Conditions: Needed to secure the remaing gas to support financing of Coyote Springs 2 Physical Gas selling @ a premium @ Malin because of shortage of transport.

System Position and Reason for Action (Attach Position Report): This purchase is to secure the remainder of the gas to run Coyote Springs 2 beginning June 2002

Dispatchability of Product: May be dropped off @ Coyote, Rathdrum or delivered to Malin for sale if not needed.

Transmission Alternatives: ____________

Building Options: GTN capacity will not be available until open season until either 11/1/03 or 11/1/04

JRT 10/2/00

**CONFIDENTIAL**

Financial and Rate Impacts: ____________________________________________

____________________________________________________________

____________________________________________________________

Market Quotes: Broker ____________ Quote ________________

Broker ____________ Quote ________________

Broker ____________ Quote ________________

Completed by: ________________________ Date: ______________________

JRT 10/2/00

# Enron Can a Corp.

March 21, 2001

CONFIDENTIAL

| AECO / NIT ($CND/GJ) | | Fixed Price ($CND/GJ) BID | Fixed Price ($CND/GJ) OFFER | Basis ($US /MMBtu) BID | Basis ($US /MMBtu) OFFER | Aeco/Empress Transport BID | Aeco/Empress Transport OFFER |
|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 7.345 | 7.355 | | | | |
| ROM | | 7.395 | 7.405 | | | - | 0.015 |
| Apr-01 | (Physical) | 7.485 | 7.495 | (0.249) | (0.229) | - | 0.025 |
| Apr-01 to Oct-01 | | 7.601 | 7.621 | (0.260) | (0.240) | (0.010) | 0.010 |
| Nov-01 to Mar-02 | | 7.810 | 7.830 | (0.205) | (0.185) | 0.140 | 0.160 |
| Apr-02 to Oct-02 | | 6.368 | 6.388 | (0.345) | (0.325) | 0.140 | 0.160 |
| Nov-01 to Oct-02 | | 6.974 | 6.994 | (0.285) | (0.265) | 0.140 | 0.160 |


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| John Disturnal | 974-6772 | Cyntia Di Stefano | 974-6750 |
| Dean Drozdiak | 974-6751 | Grant Oh | 974-6778 |


| | | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE |
|---|---|---|---|---|
| Cash | (Physical) | 1.567 | 5.080 | |
| ROM | | | 5.250 | |
| Apr-01 | | | | 5.287 |
| Apr-01 to Oct-01 | | | | 5.384 |
| Nov-01 to Mar-02 | | | | 5.475 |
| Apr-02 to Oct-02 | | | | 4.644 |
| Nov-01 to Oct-02 | | | | 4.993 |

| ROCKIES ($US/MMBtu) | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash | 4.590 | 4.610 | | |
| ROM | 4.720 | 4.740 | | |
| Apr-01 | 4.777 | 4.797 | (0.510) | (0.490) |
| Apr-01 to Oct-01 | 4.714 | 4.734 | (0.670) | (0.650) |
| Nov-01 to Mar-02 | 5.230 | 5.250 | (0.245) | (0.225) |
| Apr-02 to Oct-02 | 4.154 | 4.174 | (0.490) | (0.470) |
| Nov-01 to Oct-02 | 4.608 | 4.628 | (0.385) | (0.365) |

| SAN JUAN ($US/MMBtu) | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash | | | | |
| ROM | 4.870 | 4.890 | | |
| Apr-01 | 4.982 | 5.002 | (0.305) | (0.285) |
| Apr-01 to Oct-01 | 5.104 | 5.124 | (0.280) | (0.260) |
| Nov-01 to Mar-02 | 5.345 | 5.365 | (0.130) | (0.110) |
| Apr-02 to Oct-02 | 4.524 | 4.544 | (0.120) | (0.100) |
| Nov-01 to Oct-02 | 4.868 | 4.888 | (0.125) | (0.105) |

| DAWN ($US/MMBtu) | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash | 5.380 | 5.400 | | |
| ROM | 5.607 | 5.627 | | |
| Apr-01 | 5.592 | 5.612 | 0.305 | 0.325 |
| Apr-01 to Oct-01 | 5.664 | 5.684 | 0.280 | 0.300 |
| Nov-01 to Mar-02 | 5.845 | 5.865 | 0.370 | 0.390 |
| Apr-02 to Oct-02 | 4.879 | 4.899 | 0.235 | 0.255 |
| Nov-01 to Oct-02 | 5.288 | 5.308 | 0.295 | 0.315 |

| STATION 2 | | Fixed Price ($C/GJ) BID | Fixed Price ($C/GJ) OFFER | Basis ($US/MMBtu) BID | Basis ($US/MMBtu) OFFER |
|---|---|---|---|---|---|
| Cash | (Physical) | 7.240 | 7.270 | | |
| ROM | | 7.235 | 7.265 | | |
| Apr-01 | | 7.562 | 7.592 | (0.190) | (0.170) |
| Apr-01 to Oct-01 | | 7.700 | 7.730 | (0.190) | (0.170) |
| Nov-01 to Mar-02 | | 8.108 | 8.138 | - | 0.020 |
| Apr-02 to Oct-02 | | 6.467 | 6.497 | (0.275) | (0.255) |
| Nov-01 to Oct-02 | | 7.155 | 7.185 | (0.160) | (0.140) |

| MALIN ($US/MMBtu) | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash | 5.860 | 5.880 | | |
| ROM | 5.840 | 5.860 | | |
| Apr-01 | 7.577 | 7.597 | 2.290 | 2.310 |
| Apr-01 to Oct-01 | 8.419 | 8.439 | 3.035 | 3.055 |
| Nov-01 to Mar-02 | 8.865 | 8.885 | 3.390 | 3.410 |
| Apr-02 to Oct-02 | 5.784 | 5.804 | 1.140 | 1.160 |
| Nov-01 to Oct-02 | 7.078 | 7.098 | 2.085 | 2.105 |

| VENTURA ($US/MMBtu) | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash | 5.045 | 5.065 | | |
| ROM | 5.300 | 5.320 | | |
| Apr-01 | 5.327 | 5.347 | 0.040 | 0.060 |
| Apr-01 to Oct-01 | 5.414 | 5.434 | 0.030 | 0.050 |
| Nov-01 to Mar-02 | 5.625 | 5.645 | 0.150 | 0.170 |
| Apr-02 to Oct-02 | 4.664 | 4.684 | 0.020 | 0.040 |
| Nov-01 to Oct-02 | 5.068 | 5.088 | 0.075 | 0.095 |

| NIAGARA ($US/MMBtu) | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash | 5.405 | 5.425 | | |
| ROM | 5.667 | 5.687 | | |
| Apr-01 | 5.632 | 5.652 | 0.345 | 0.365 |
| Apr-01 to Oct-01 | 5.704 | 5.724 | 0.320 | 0.340 |
| Nov-01 to Mar-02 | 6.020 | 6.040 | 0.545 | 0.565 |
| Apr-02 to Oct-02 | 4.924 | 4.944 | 0.280 | 0.300 |
| Nov-01 to Oct-02 | 5.383 | 5.403 | 0.390 | 0.410 |

| SUMAS ($US/MMBtu) | | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|
| Cash | (Physical) | 5.045 | 5.065 | | |
| ROM | | 5.250 | 5.270 | | |
| Apr-01 | | 5.257 | 5.277 | (0.030) | (0.010) |
| Apr-01 to Oct-01 | | 5.294 | 5.314 | (0.090) | (0.070) |
| Nov-01 to Mar-02 | | 7.380 | 7.400 | 1.905 | 1.925 |
| Apr-02 to Oct-02 | | 4.544 | 4.564 | (0.100) | (0.080) |
| Nov-01 to Oct-02 | | 5.733 | 5.753 | 0.740 | 0.760 |

| SoCAL ($US/MMBtu) | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash | 11.025 | 11.045 | | |
| ROM | 10.820 | 10.840 | | |
| Apr-01 | 10.277 | 10.297 | 4.990 | 5.010 |
| Apr-01 to Oct-01 | 10.339 | 10.359 | 4.955 | 4.975 |
| Nov-01 to Mar-02 | 9.865 | 9.885 | 4.390 | 4.410 |
| Apr-02 to Oct-02 | 6.284 | 6.304 | 1.640 | 1.660 |
| Nov-01 to Oct-02 | 7.788 | 7.808 | 2.795 | 2.815 |

| CHICAGO CITY GATE ($US/MMBtu) | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash | 5.215 | 5.235 | | |
| ROM | 5.410 | 5.430 | | |
| Apr-01 | 5.442 | 5.462 | 0.155 | 0.175 |
| Apr-01 to Oct-01 | 5.534 | 5.554 | 0.150 | 0.170 |
| Nov-01 to Mar-02 | 5.725 | 5.745 | 0.250 | 0.270 |
| Apr-02 to Oct-02 | 4.764 | 4.784 | 0.120 | 0.140 |
| Nov-01 to Oct-02 | 5.168 | 5.188 | 0.175 | 0.195 |

| TRANSCO Z6 ($US/MMBtu) | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash | 5.540 | 5.560 | | |
| ROM | 5.720 | 5.740 | | |
| Apr-01 | 5.717 | 5.737 | 0.430 | 0.450 |
| Apr-01 to Oct-01 | 5.864 | 5.884 | 0.480 | 0.500 |
| Nov-01 to Mar-02 | 7.025 | 7.045 | 1.550 | 1.570 |
| Apr-02 to Oct-02 | 5.109 | 5.129 | 0.465 | 0.485 |
| Nov-01 to Oct-02 | 5.913 | 5.933 | 0.920 | 0.940 |

[redacted]

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# Enron Ca. .da Corp.
March 23, 2001

| AECO / NIT ($CND/GJ) | | Fixed Price ($CND/GJ) BID | Fixed Price ($CND/GJ) OFFER | Basis ($US /MMBtu) BID | Basis ($US /MMBtu) OFFER | Aeco/Empress Transport BID | Aeco/Empress Transport OFFER |
|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 7.270 | 7.280 | | | | |
| ROM | | 7.445 | 7.455 | | | - | 0.015 |
| Apr-01 | (Physical) | 7.485 | 7.495 | (0.190) | (0.170) | - | 0.025 |
| Apr-01 to Oct-01 | | 7.590 | 7.610 | (0.210) | (0.190) | (0.010) | 0.010 |
| Nov-01 to Mar-02 | | 7.762 | 7.782 | (0.180) | (0.160) | 0.140 | 0.160 |
| Apr-02 to Oct-02 | | 6.227 | 6.247 | (0.300) | (0.280) | 0.140 | 0.160 |
| Nov-01 to Oct-02 | | 6.870 | 6.890 | (0.250) | (0.230) | 0.140 | 0.160 |


MAIN PHONE
(403) 974-6701

MAIN FAX
(403) 974-6706

| | | | |
|---|---|---|---|
| Howard Sangwine | 974-6704 | Eric Le Dain | 974-6741 |
| Mike Cowan | 974-6712 | Jon McKay | 974-6733 |
| Derek Davies | 974-6793 | Rob Milnthorp | 974-6714 |
| John Disturnal | 974-6772 | Cynlia Di Stefano | 974-6750 |
| Dean Drozdiak | 974-6751 | Grant Oh | 974-6778 |


| | | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE |
|---|---|---|---|---|
| Cash | (Physical) | 1.571 | 5.025 | |
| ROM | | | 5.170 | |
| Apr-01 | | | | 5.212 |
| Apr-01 to Oct-01 | | | | 5.310 |
| Nov-01 to Mar-02 | | | | 5.401 |
| Apr-02 to Oct-02 | | | | 4.489 |
| Nov-01 to Oct-02 | | | | 4.871 |

| | ROCKIES ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SAN JUAN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | DAWN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash | 4.645 | 4.665 | | | | | | | 5.335 | 5.355 | | |
| ROM | 4.540 | 4.560 | | | 4.740 | 4.760 | | | 5.540 | 5.560 | | |
| Apr-01 | 4.662 | 4.682 | (0.550) | (0.530) | 4.872 | 4.892 | (0.340) | (0.320) | 5.542 | 5.562 | 0.330 | 0.350 |
| Apr-01 to Oct-01 | 4.590 | 4.610 | (0.720) | (0.700) | 4.955 | 4.975 | (0.355) | (0.335) | 5.605 | 5.625 | 0.295 | 0.315 |
| Nov-01 to Mar-02 | 5.131 | 5.151 | (0.270) | (0.250) | 5.241 | 5.261 | (0.160) | (0.140) | 5.786 | 5.806 | 0.385 | 0.405 |
| Apr-02 to Oct-02 | 3.974 | 3.994 | (0.515) | (0.495) | 4.369 | 4.389 | (0.120) | (0.100) | 4.734 | 4.754 | 0.245 | 0.265 |
| Nov-01 to Oct-02 | 4.461 | 4.481 | (0.410) | (0.390) | 4.736 | 4.756 | (0.135) | (0.115) | 5.176 | 5.196 | 0.305 | 0.325 |

| | | STATION 2 Fixed Price ($C/GJ) BID | Fixed Price ($C/GJ) OFFER | Basis ($US/MMBtu) BID | Basis ($US/MMBtu) OFFER | MALIN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | VENTURA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | NIAGARA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 7.320 | 7.350 | | | 5.725 | 5.745 | | | 5.045 | 5.065 | | | 5.350 | 5.370 | | |
| ROM | | 7.485 | 7.515 | | | 6.640 | 6.660 | | | 5.220 | 5.240 | | | 5.600 | 5.620 | | |
| Apr-01 | | 7.557 | 7.587 | (0.135) | (0.115) | 7.652 | 7.672 | 2.440 | 2.460 | 5.257 | 5.277 | 0.045 | 0.065 | 5.582 | 5.602 | 0.370 | 0.390 |
| Apr-01 to Oct-01 | | 7.696 | 7.726 | (0.135) | (0.115) | 8.470 | 8.490 | 3.160 | 3.180 | 5.345 | 5.365 | 0.035 | 0.055 | 5.645 | 5.665 | 0.335 | 0.355 |
| Nov-01 to Mar-02 | | 8.047 | 8.077 | 0.015 | 0.035 | 8.841 | 8.861 | 3.440 | 3.460 | 5.556 | 5.576 | 0.155 | 0.175 | 5.961 | 5.981 | 0.560 | 0.580 |
| Apr-02 to Oct-02 | | 6.318 | 6.348 | (0.235) | (0.215) | 5.659 | 5.679 | 1.170 | 1.190 | 4.514 | 4.534 | 0.025 | 0.045 | 4.779 | 4.799 | 0.290 | 0.310 |
| Nov-01 to Oct-02 | | 7.043 | 7.073 | (0.130) | (0.110) | 6.991 | 7.011 | 2.120 | 2.140 | 4.951 | 4.971 | 0.080 | 0.100 | 5.276 | 5.296 | 0.405 | 0.425 |

| | | SUMAS ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SoCAL ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | CHICAGO CITY GATE ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | TRANSCO Z6 ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 5.055 | 5.075 | | | 10.985 | 11.005 | | | 5.165 | 5.185 | | | 5.475 | 5.495 | | |
| ROM | | 5.220 | 5.240 | | | 11.040 | 11.060 | | | 5.330 | 5.350 | | | 5.630 | 5.650 | | |
| Apr-01 | | 5.192 | 5.212 | (0.020) | - | 10.352 | 10.372 | 5.140 | 5.160 | 5.377 | 5.397 | 0.165 | 0.185 | 5.652 | 5.672 | 0.440 | 0.460 |
| Apr-01 to Oct-01 | | 5.250 | 5.270 | (0.060) | (0.040) | 10.390 | 10.410 | 5.080 | 5.100 | 5.470 | 5.490 | 0.160 | 0.180 | 5.800 | 5.820 | 0.490 | 0.510 |
| Nov-01 to Mar-02 | | 7.356 | 7.376 | 1.955 | 1.975 | 9.841 | 9.861 | 4.440 | 4.460 | 5.666 | 5.686 | 0.265 | 0.285 | 6.951 | 6.971 | 1.550 | 1.570 |
| Apr-02 to Oct-02 | | 4.389 | 4.409 | (0.100) | (0.080) | 6.159 | 6.179 | 1.670 | 1.690 | 4.609 | 4.629 | 0.120 | 0.140 | 4.954 | 4.974 | 0.465 | 0.485 |
| Nov-01 to Oct-02 | | 5.631 | 5.651 | 0.760 | 0.780 | 7.701 | 7.721 | 2.830 | 2.850 | 5.051 | 5.071 | 0.180 | 0.200 | 5.791 | 5.811 | 0.920 | 0.940 |

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Avista Utilities
Gas/Electric Transaction

Date of Transaction: 4/10/01 Reference No. ____________

Transaction Details: Purchase / Sale (Circle) Financial

Delivery Period June 1, 2002 Thru October 31, 2003

Volume 10,000 MMBtu/day

Location ____________

Price Fixed Price, (Lock in Malin NGI monthly Index @ $6.50

~~Broker~~ Avista Energy

Market Conditions: Forward Electric Prices Calendar 2002, 2003 & 2004 heavy load are approx. $181.50, $84.50 & $66.00 respectively

System Position and Reason for Action (Attach Position Report): The gas to run Coyote has been purchased @ an index price - locking in the gas price fixes the cost of generation significantly below the forward market price of power. (See calculations on back)

Dispatchability of Product: ____________

Transmission Alternatives: ____________

Building Options: ____________

JRT 10/2/00

**CONFIDENTIAL**

Financial and Rate Impacts: Gas price lockedin to fix cost to generate @ Coyote Springs 2 - significantly below forward power prices.

Market Quotes: Broker ____________ Quote ______________

Broker ____________ Quote ______________

Broker ____________ Quote ______________

Completed by: ______________________ Date: ____________________

\$6.50 fixed price + \$.06 original purchase over index = \$6.56

\$6.56 X 6.9 HR = \$45.26/MW Cost to generate

Market Price of Power HL 2002 \$191.50/MW

HL 2003 84.50/MW

HL 2004 66.00/MW

JRT 10/2/00

2006

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## Corporation

### Gas Supply

Price Quotation Summary Sheet

PAPER SWAP

Date: 4/10/01 Company: AVISTA ENERGY

Representative:

(Name) MIKE D'ARIENZO

(Title) VP GAS MARKETING

(Phone #)

(FAX #)

Volume: 10,000 MMBtu Price Quoted: $ 6.50 /MMBtu

Period: From: JUNE 1, 2002 To: OCT 31, 2003

Type: ☐ Firm ☐ Interruptible ☒ PAPER

Maximum Take: 10,000 MMBtu per ☒ Day ☐ Month

Minimum Take: ______ MMBtu per ☐ Day ☐ Month

Reservation Fee: $ ______ /MMBtu

Receipt Point: MALIN INDEX PAID BY A. ENERGY

Pipeline: ☐ Northwest ☒ PGT $6.50/MMBTU PAID BY AVISTA CORP

☒ Accepted ☐ Rejected Date: 4/10/01

TO FIX THE PRICE FOR CS2 SUPPLY.

IF ACCEPTED: Date of Contract:

Company Address:

Accounting Contact:
(Name)
(Phone #)
(FAX #)

Wire Transfer Contact:
(Name)
(Phone #)
(FAX #)
Bank:
Account #:
Date of Payment:

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# Avista Utilities

Position Report

2001-04-09.xls

Indicates positions outside of risk policy limits

| Month | Hrs | Index Purchase (Sale) [a] Col (1) | Physical Position Long (Short) [b] Col (2) | Financial Put (Call) Net Delta [c] Col (3) | Total Position Long (Short) [d] Col (4) Col (2) + Col (3) | CT Inc in Phy Fuel Pur Col (5) | CT Turb. Fuel Not Pur [e] Col (6) | Physical Open Position [f] Col (7) Col (4) + Col (6) | Financial Open Position [g] Col (8) Col (7) - Col (1) | Financial Quarter Average Col (9) Avg Col 8 | Fin & NG Open Position [h] Col (10) Col (8) - Col (6) | Month Short Limit Col (11) | Month Long Limit Col (12) | Fin & NG Quarter Average Col (13) Avg Col 10 | Quarter Short Limit Col (14) | Quarter Long Limit Col (15) | Month | Hrs | Hrs | Impact of $50 Price Increase |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| May-01 | HL | (5) | 26 | 0 | 26 | 123 | 58 | 84 | 89 | | 31 | (25) | 125 | | | | May-01 | HL | 416 | $ 1,859,850 |
| May-01 | LL | (5) | 45 | 0 | 45 | 121 | 55 | 100 | 105 | | 50 | (25) | 125 | | | | May-01 | LL | 328 | $ 1,717,850 |
| Jun-01 | HL | (5) | (55) | 0 | (55) | 124 | 0 | (55) | (50) | | (50) | (25) | 125 | | | | Jun-01 | HL | 416 | $ (1,046,450) |
| Jun-01 | LL | (5) | 52 | 0 | 52 | 120 | 0 | 52 | 57 | | 57 | (25) | 125 | | | | Jun-01 | LL | 304 | $ 869,000 |
| Jul-01 | HL | (5) | (6) | 0 | (6) | 150 | 0 | (6) | (1) | | (1) | (75) | 200 | | | | Jul-01 | HL | 400 | $ (11,400) |
| Jul-01 | LL | (5) | 57 | 0 | 57 | 150 | 0 | 57 | 62 | | 62 | (75) | 200 | | | | Jul-01 | LL | 344 | $ 1,060,750 |
| Aug-01 | HL | 5 | (3) | 0 | (3) | 200 | 0 | (3) | (8) | 52 | (8) | (75) | 200 | 52 | (25) | 150 | Aug-01 | HL | 432 | $ (176,750) |
| Aug-01 | LL | 5 | 51 | 0 | 51 | 200 | 0 | 51 | 46 | 73 | 46 | (75) | 200 | 73 | (25) | 150 | Aug-01 | LL | 312 | $ 722,150 |
| Sep-01 | HL | (5) | 159 | 0 | 159 | 208 | 0 | 159 | 164 | | 164 | (75) | 200 | | | | Sep-01 | HL | 384 | $ 3,155,300 |
| Sep-01 | LL | (5) | 107 | 0 | 107 | 208 | 0 | 107 | 112 | | 112 | (75) | 200 | | | | Sep-01 | LL | 336 | $ 1,889,200 |
| Oct-01 | HL | (5) | 7 | 0 | 7 | 208 | 0 | 7 | 12 | | 12 | (150) | 250 | | | | Oct-01 | HL | 432 | $ 250,500 |
| Oct-01 | LL | (5) | 100 | 0 | 100 | 208 | 0 | 100 | 105 | | 105 | (150) | 250 | | | | Oct-01 | LL | 312 | $ 1,633,000 |
| Nov-01 | HL | (5) | 120 | 0 | 120 | 219 | 0 | 120 | 125 | 95 | 125 | (150) | 250 | 95 | (50) | 150 | Nov-01 | HL | 400 | $ 2,496,600 |
| Nov-01 | LL | (5) | 85 | (90) | (4) | 160 | 0 | (4) | 1 | 22 | 1 | (150) | 250 | 22 | (50) | 150 | Nov-01 | LL | 320 | $ 12,400 |
| Dec-01 | HL | (5) | 144 | 0 | 144 | 219 | 0 | 144 | 149 | | 149 | (150) | 250 | | | | Dec-01 | HL | 400 | $ 2,976,600 |
| Dec-01 | LL | (5) | 40 | (85) | (45) | 160 | 0 | (45) | (40) | | (40) | (150) | 250 | | | | Dec-01 | LL | 344 | $ (696,350) |
| Jan-02 | HL | (5) | 106 | 0 | 106 | 99 | 61 | 167 | 172 | | 111 | (150) | 250 | | | | Jan-02 | HL | 416 | $ 3,584,700 |
| Jan-02 | LL | (5) | 113 | (87) | 26 | 99 | 61 | 87 | 92 | | 31 | (150) | 250 | | | | Jan-02 | LL | 328 | $ 1,508,100 |
| Feb-02 | HL | (5) | 97 | 0 | 97 | 99 | 41 | 138 | 143 | 156 | 102 | (150) | 250 | 115 | (50) | 150 | Feb-02 | HL | 384 | $ 2,747,100 |
| Feb-02 | LL | (5) | 163 | (87) | 76 | 99 | 41 | 117 | 122 | 111 | 81 | (150) | 250 | 70 | (50) | 150 | Feb-02 | LL | 288 | $ 1,753,150 |
| Mar-02 | HL | (5) | 127 | 0 | 127 | 99 | 19 | 146 | 151 | | 132 | (150) | 250 | | | | Mar-02 | HL | 416 | $ 3,144,400 |
| Mar-02 | LL | (5) | 180 | (87) | 93 | 99 | 20 | 113 | 118 | | 98 | (150) | 250 | | | | Mar-02 | LL | 328 | $ 1,938,200 |
| Apr-02 | HL | (5) | 147 | (91) | 56 | 99 | 56 | 112 | 117 | | 61 | (150) | 250 | | | | Apr-02 | HL | 416 | $ 2,430,700 |
| Apr-02 | LL | (5) | 144 | (76) | 68 | 99 | 56 | 124 | 129 | | 73 | (150) | 250 | | | | Apr-02 | LL | 304 | $ 1,958,950 |
| May-02 | HL | (5) | 196 | 0 | 196 | 99 | 47 | 243 | 248 | 187 | 201 | (150) | 250 | 153 | (50) | 150 | May-02 | HL | 416 | $ 5,167,200 |
| May-02 | LL | (5) | 173 | 0 | 173 | 99 | 44 | 217 | 222 | 188 | 178 | (150) | 250 | 155 | (50) | 150 | May-02 | LL | 328 | $ 3,643,150 |
| Jun-02 | HL | (5) | 289 | (97) | 192 | 119 | 0 | 192 | 197 | | 197 | (150) | 250 | | | | Jun-02 | HL | 400 | $ 3,941,200 |
| Jun-02 | LL | (5) | 293 | (83) | 209 | 119 | 0 | 209 | 214 | | 214 | (150) | 250 | | | | Jun-02 | LL | 320 | $ 3,431,650 |
| Jul-02 | HL | (5) | 242 | 0 | 242 | 150 | 0 | 242 | 247 | | 247 | (175) | 250 | | | | Jul-02 | HL | 416 | $ 5,127,400 |
| Jul-02 | LL | (5) | 214 | 0 | 214 | 150 | 0 | 214 | 219 | | 219 | (175) | 250 | | | | Jul-02 | LL | 328 | $ 3,591,800 |
| | | | | | | | | | | | | | | | | | Jan-00 | 0 | | |
| Aug-02 | HL | 5 | (52) | 0 | (52) | 260 | 200 | 148 | 143 | 189 | (57) | (175) | 250 | 53 | (75) | 150 | Aug-02 | HL | 432 | $ 3,099,450 |
| Aug-02 | LL | 5 | 245 | 0 | 245 | 260 | 200 | 445 | 440 | 377 | 240 | (175) | 250 | 241 | (75) | 150 | Aug-02 | LL | 312 | $ 6,856,750 |
| Sep-02 | HL | (5) | (37) | 0 | (37) | 265 | 208 | 171 | 176 | | (32) | (175) | 250 | | | | Sep-02 | HL | 384 | $ 3,374,350 |
| Sep-02 | LL | (5) | 260 | 0 | 260 | 265 | 208 | 468 | 473 | | 265 | (175) | 250 | | | | Sep-02 | LL | 336 | $ 7,946,250 |
| Oct-02 | HL | (5) | 87 | 0 | 87 | 265 | 208 | 295 | 300 | | 92 | (175) | 250 | | | | Oct-02 | HL | 432 | $ 6,478,550 |
| Oct-02 | LL | (5) | 264 | 0 | 264 | 265 | 208 | 472 | 477 | | 269 | (175) | 250 | | | | Oct-02 | LL | 312 | $ 7,437,100 |

Footnotes: [a] Index transactions are already included in the total physical position. [b] Physical position. [c] Aggregate physical equivalent (delta) position of options (put and calls). [d] Total position is the combined physical and delta positions. [e] Turbines in this column are available for use, but gas has not been purchased. When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column. [f] Open physical position includes total position and available turbines. [g] Open financial position includes open physical position less any index position. [h] Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased.

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# Avista Utilities

## Physical Surplus-(Deficiency)

2001-04-09.xls

Indicates Changes

| Month | Hours | Native Load | Contract Purchases | Contract Sales | PURPA Contracts | Colstrip | Kettle Falls | NECT | Rathdrum | Coyote Springs | Mid -C Hydro | Clark Fork Hydro | Spokane Hydro | Total Resource | Total Obligation | Physical Surplus/ (Deficiency) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) |
| May-01 | HL | 1,037 | (654) | 820 | (62) | (195) | (26) | (35) | (88) | 0 | (119) | (536) | (170) | (1,884) | 1,858 | 26 |
| May-01 | LL | 830 | (697) | 626 | (62) | (203) | (27) | (33) | (88) | 0 | (65) | (173) | (153) | (1,501) | 1,456 | 45 |
| Jun-01 | HL | 1,016 | (678) | 910 | (31) | (216) | (48) | 0 | (124) | 0 | (118) | (500) | (155) | (1,871) | 1,926 | (55) |
| Jun-01 | LL | 798 | (727) | 595 | (31) | (216) | (48) | 0 | (120) | 0 | (62) | (164) | (77) | (1,445) | 1,393 | 52 |
| Jul-01 | HL | 1,122 | (1,004) | 947 | (62) | (216) | (48) | 0 | (150) | 0 | (128) | (394) | (61) | (2,063) | 2,069 | (6) |
| Jul-01 | LL | 867 | (768) | 594 | (62) | (216) | (48) | 0 | (150) | 0 | (72) | (148) | (53) | (1,518) | 1,461 | 57 |
| Aug-01 | HL | 1,155 | (865) | 618 | (62) | (216) | (48) | (50) | (150) | 0 | (110) | (223) | (47) | (1,770) | 1,774 | (3) |
| Aug-01 | LL | 862 | (587) | 359 | (62) | (216) | (48) | (50) | (150) | 0 | (58) | (80) | (21) | (1,272) | 1,221 | 51 |
| Sep-01 | HL | 1,016 | (855) | 531 | (54) | (216) | (48) | (52) | (156) | 0 | (88) | (172) | (66) | (1,706) | 1,547 | 159 |
| Sep-01 | LL | 809 | (567) | 345 | (54) | (216) | (48) | (52) | (156) | 0 | (50) | (80) | (38) | (1,261) | 1,154 | 107 |
| Oct-01 | HL | 1,045 | (508) | 357 | (62) | (216) | (48) | (52) | (156) | 0 | (91) | (199) | (77) | (1,409) | 1,402 | 7 |
| Oct-01 | LL | 829 | (455) | 234 | (62) | (216) | (48) | (52) | (156) | 0 | (47) | (75) | (51) | (1,163) | 1,063 | 100 |
| Nov-01 | HL | 1,167 | (592) | 356 | (62) | (216) | (48) | (59) | (160) | 0 | (106) | (282) | (118) | (1,643) | 1,523 | 120 |
| Nov-01 | LL | 954 | (568) | 241 | (62) | (216) | (48) | 0 | (160) | 0 | (59) | (103) | (65) | (1,280) | 1,195 | 85 |
| Dec-01 | HL | 1,256 | (613) | 352 | (62) | (216) | (48) | (59) | (160) | 0 | (128) | (310) | (157) | (1,752) | 1,609 | 144 |
| Dec-01 | LL | 1,038 | (565) | 241 | (62) | (216) | (48) | 0 | (160) | 0 | (72) | (117) | (78) | (1,319) | 1,279 | 40 |
| Jan-02 | HL | 1,265 | (415) | 126 | (62) | (216) | (48) | 0 | (99) | 0 | (179) | (310) | (169) | (1,498) | 1,391 | 106 |
| Jan-02 | LL | 1,043 | (473) | 26 | (62) | (216) | (48) | 0 | (99) | 0 | (98) | (108) | (77) | (1,181) | 1,068 | 113 |
| Feb-02 | HL | 1,204 | (413) | 122 | (62) | (216) | (48) | 0 | (99) | 0 | (152) | (255) | (178) | (1,423) | 1,326 | 97 |
| Feb-02 | LL | 1,000 | (476) | 20 | (62) | (216) | (48) | 0 | (99) | 0 | (81) | (90) | (111) | (1,183) | 1,020 | 163 |
| Mar-02 | HL | 1,112 | (349) | 119 | (62) | (216) | (48) | 0 | (99) | 0 | (126) | (280) | (178) | (1,359) | 1,231 | 127 |
| Mar-02 | LL | 927 | (410) | 20 | (62) | (216) | (48) | 0 | (99) | 0 | (69) | (101) | (123) | (1,127) | 947 | 180 |
| Apr-02 | HL | 1,068 | (100) | 123 | (62) | (216) | (48) | 0 | (99) | 0 | (103) | (492) | (217) | (1,338) | 1,191 | 147 |
| Apr-02 | LL | 866 | (215) | 20 | (62) | (216) | (48) | 0 | (99) | 0 | (54) | (175) | (162) | (1,030) | 886 | 144 |
| May-02 | HL | 1,060 | (58) | 123 | (62) | (108) | (28) | 0 | (99) | 0 | (114) | (740) | (170) | (1,379) | 1,183 | 196 |
| May-02 | LL | 854 | (150) | 26 | (62) | (108) | (25) | 0 | (99) | 0 | (62) | (405) | (142) | (1,053) | 880 | 173 |
| Jun-02 | HL | 1,038 | (58) | 147 | (31) | (151) | (48) | 0 | (119) | 0 | (139) | (750) | (178) | (1,474) | 1,185 | 289 |
| Jun-02 | LL | 827 | (150) | 20 | (31) | (151) | (48) | 0 | (119) | 0 | (77) | (459) | (105) | (1,140) | 847 | 293 |
| Jul-02 | HL | 1,158 | (258) | 157 | (62) | (216) | (48) | 0 | (150) | 0 | (124) | (570) | (128) | (1,556) | 1,315 | 242 |
| Jul-02 | LL | 894 | (350) | 27 | (62) | (216) | (48) | 0 | (150) | 0 | (67) | (175) | (67) | (1,135) | 921 | 214 |
| Aug-02 | HL | 1,175 | (268) | 262 | (62) | (216) | (48) | 0 | 0 | (260) | (129) | (320) | (83) | (1,386) | 1,437 | (52) |
| Aug-02 | LL | 882 | (365) | 20 | (62) | (216) | (48) | 0 | 0 | (260) | (67) | (100) | (29) | (1,147) | 902 | 245 |
| Sep-02 | HL | 1,040 | (258) | 242 | (54) | (216) | (48) | 0 | 0 | (265) | (105) | (199) | (100) | (1,245) | 1,282 | (37) |
| Sep-02 | LL | 830 | (345) | 33 | (54) | (216) | (48) | 0 | 0 | (265) | (60) | (88) | (48) | (1,124) | 864 | 260 |
| Oct-02 | HL | 1,069 | (258) | 121 | (62) | (216) | (48) | 0 | 0 | (265) | (106) | (202) | (119) | (1,276) | 1,189 | 87 |
| Oct-02 | LL | 853 | (355) | 20 | (62) | (216) | (48) | 0 | 0 | (265) | (55) | (76) | (60) | (1,137) | 873 | 264 |

# Enron Canada Corp.
April 10, 2001

CONFIDENTIAL

| AECO / NIT ($CND/GJ) | | Fixed Price ($CND/GJ) BID | OFFER | Basis ($US /MMBtu) BID | OFFER | Aeco/Empress Transport BID | OFFER |
|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 7.718 | 7.728 | | | | |
| ROM | | 7.693 | 7.703 | | | - | 0.015 |
| May-01 | (Physical) | 7.725 | 7.735 | (0.270) | (0.250) | - | 0.025 |
| May-01 to | Oct-01 | 7.857 | 7.877 | (0.270) | (0.250) | (0.010) | 0.010 |
| Nov-01 to | Mar-02 | 8.175 | 8.195 | (0.190) | (0.170) | 0.140 | 0.160 |
| Apr-02 to | Oct-02 | 6.522 | 6.542 | (0.295) | (0.275) | 0.140 | 0.160 |
| Nov-01 to | Oct-02 | 7.217 | 7.237 | (0.250) | (0.230) | 0.140 | 0.160 |


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| | | | |
|---|---|---|---|
| Howard Sangwine | 974-6704 | Eric Le Dain | 974-6741 |
| Mike Cowan | 974-6712 | Jon McKay | 974-6733 |
| Derek Davies | 974-6793 | Rob Milnthorp | 974-6714 |
| John Disturnal | 974-6772 | Cyntia Di Stefano | 974-6750 |
| Dean Drozdiak | 974-6751 | Grant Oh | 974-6778 |


| | | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE |
|---|---|---|---|---|
| Cash | (Physical) | 1.565 | 5.470 | |
| ROM | | | 5.440 | |
| May-01 | | | | 5.477 |
| May-01 to | Oct-01 | | | 5.571 |
| Nov-01 to | Mar-02 | | | 5.705 |
| Apr-02 to | Oct-02 | | | 4.692 |
| Nov-01 to | Oct-02 | | | 5.117 |

| | | ROCKIES ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | SAN JUAN ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | DAWN ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 4.775 | 4.795 | | | 4.930 | 4.950 | | | 5.795 | 5.815 | | |
| ROM | | 4.580 | 4.600 | | | 4.630 | 4.650 | | | 5.770 | 5.790 | | |
| May-01 | | 4.637 | 4.657 | (0.840) | (0.820) | 4.927 | 4.947 | (0.550) | (0.530) | 5.772 | 5.792 | 0.295 | 0.315 |
| May-01 to | Oct-01 | 4.661 | 4.681 | (0.910) | (0.890) | 5.081 | 5.101 | (0.490) | (0.470) | 5.856 | 5.876 | 0.285 | 0.305 |
| Nov-01 to | Mar-02 | 5.425 | 5.445 | (0.280) | (0.260) | 5.530 | 5.550 | (0.175) | (0.155) | 6.110 | 6.130 | 0.405 | 0.425 |
| Apr-02 to | Oct-02 | 4.092 | 4.112 | (0.600) | (0.580) | 4.537 | 4.557 | (0.155) | (0.135) | 4.947 | 4.967 | 0.255 | 0.275 |
| Nov-01 to | Oct-02 | 4.652 | 4.672 | (0.465) | (0.445) | 4.952 | 4.972 | (0.165) | (0.145) | 5.437 | 5.457 | 0.320 | 0.340 |

| | | STATION 2 Fixed Price ($C/GJ) BID | OFFER | Basis ($US/MMBtu) BID | OFFER | MALIN ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | VENTURA ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | NIAGARA ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 7.615 | 7.645 | | | 10.655 | 10.675 | | | 5.390 | 5.410 | | | 5.785 | 5.805 | | |
| ROM | | 7.785 | 7.815 | | | 9.630 | 9.650 | | | 5.430 | 5.450 | | | 5.790 | 5.810 | | |
| May-01 | | 7.766 | 7.796 | (0.235) | (0.215) | 9.467 | 9.487 | 3.990 | 4.010 | 5.512 | 5.532 | 0.035 | 0.055 | 5.802 | 5.822 | 0.325 | 0.345 |
| May-01 to | Oct-01 | 7.941 | 7.971 | (0.210) | (0.190) | 9.751 | 9.771 | 4.180 | 4.200 | 5.596 | 5.616 | 0.025 | 0.045 | 5.886 | 5.906 | 0.315 | 0.335 |
| Nov-01 to | Mar-02 | 8.452 | 8.482 | - | 0.020 | 11.345 | 11.365 | 5.640 | 5.660 | 5.880 | 5.900 | 0.175 | 0.195 | 6.270 | 6.290 | 0.565 | 0.585 |
| Apr-02 to | Oct-02 | 6.614 | 6.644 | (0.230) | (0.210) | 6.382 | 6.402 | 1.690 | 1.710 | 4.722 | 4.742 | 0.030 | 0.050 | 4.992 | 5.012 | 0.300 | 0.320 |
| Nov-01 to | Oct-02 | 7.390 | 7.420 | (0.130) | (0.110) | 8.462 | 8.482 | 3.345 | 3.365 | 5.207 | 5.227 | 0.090 | 0.110 | 5.527 | 5.547 | 0.410 | 0.430 |

| | | SUMAS ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | SoCAL ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | CHICAGO CITY GATE ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | TRANSCO Z6 ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 5.570 | 5.590 | | | 13.740 | 13.760 | | | 5.550 | 5.570 | | | 5.940 | 5.960 | | |
| ROM | | 5.540 | 5.560 | | | 14.130 | 14.150 | | | 5.540 | 5.560 | | | 5.880 | 5.900 | | |
| May-01 | | 5.547 | 5.567 | 0.070 | 0.090 | 13.567 | 13.587 | 8.090 | 8.110 | 5.612 | 5.632 | 0.135 | 0.155 | 5.922 | 5.942 | 0.445 | 0.465 |
| May-01 to | Oct-01 | 5.616 | 5.636 | 0.045 | 0.065 | 13.621 | 13.641 | 8.050 | 8.070 | 5.711 | 5.731 | 0.140 | 0.160 | 6.071 | 6.091 | 0.500 | 0.520 |
| Nov-01 to | Mar-02 | 9.715 | 9.735 | 4.010 | 4.030 | 13.395 | 13.415 | 7.690 | 7.710 | 5.955 | 5.975 | 0.250 | 0.270 | 7.415 | 7.435 | 1.710 | 1.730 |
| Apr-02 to | Oct-02 | 4.682 | 4.702 | (0.010) | 0.010 | 7.782 | 7.802 | 3.090 | 3.110 | 4.812 | 4.832 | 0.120 | 0.140 | 5.157 | 5.177 | 0.465 | 0.485 |
| Nov-01 to | Oct-02 | 6.792 | 6.812 | 1.675 | 1.695 | 10.137 | 10.157 | 5.020 | 5.040 | 5.292 | 5.312 | 0.175 | 0.195 | 6.102 | 6.122 | 0.985 | 1.005 |

CONFIDENTIAL

# Enron Ca..da Corp.
April 11, 2001

| AECO / NIT ($CND/GJ) | | Fixed Price ($CND/GJ) BID | Fixed Price OFFER | Basis ($US /MMBtu) BID | Basis OFFER | Aeco/Empress Transport BID | Transport OFFER |
|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 7.790 | 7.800 | | | | |
| ROM | | 7.775 | 7.785 | | | - | 0.015 |
| May-01 | (Physical) | 7.810 | 7.820 | (0.264) | (0.244) | - | 0.025 |
| May-01 to Oct-01 | | 7.920 | 7.940 | (0.270) | (0.250) | (0.010) | 0.010 |
| Nov-01 to Mar-02 | | 8.225 | 8.245 | (0.190) | (0.170) | 0.140 | 0.160 |
| Apr-02 to Oct-02 | | 6.530 | 6.550 | (0.295) | (0.275) | 0.140 | 0.160 |
| Nov-01 to Oct-02 | | 7.242 | 7.262 | (0.250) | (0.230) | 0.140 | 0.160 |


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| Mike Cowan | 974-6712 | Jon McKay | 974-6733 |
| Derek Davies | 974-6793 | Rob Milnthorp | 974-6714 |
| John Disturnal | 974-6772 | Cyntia Di Stefano | 974-6750 |
| Dean Drozdiak | 974-6751 | Grant Oh | 974-6778 |


| | | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE |
|---|---|---|---|---|
| Cash | (Physical) | 1.556 | 5.545 | |
| ROM | | | 5.530 | |
| May-01 | | | | 5.559 |
| May-01 to Oct-01 | | | | 5.645 |
| Nov-01 to Mar-02 | | | | 5.775 |
| Apr-02 to Oct-02 | | | | 4.729 |
| Nov-01 to Oct-02 | | | | 5.168 |

| | ROCKIES ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SAN JUAN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | DAWN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 4.965 | 4.985 | | | 4.980 | 5.000 | | | 5.855 | 5.875 | | |
| ROM | 4.670 | 4.690 | | | 4.870 | 4.890 | | | 5.870 | 5.890 | | |
| May-01 | 4.689 | 4.709 | (0.870) | (0.850) | 4.944 | 4.964 | (0.615) | (0.595) | 5.849 | 5.869 | 0.290 | 0.310 |
| May-01 to Oct-01 | 4.710 | 4.730 | (0.935) | (0.915) | 5.125 | 5.145 | (0.520) | (0.500) | 5.925 | 5.945 | 0.280 | 0.300 |
| Nov-01 to Mar-02 | 5.485 | 5.505 | (0.290) | (0.270) | 5.605 | 5.625 | (0.170) | (0.150) | 6.190 | 6.210 | 0.415 | 0.435 |
| Apr-02 to Oct-02 | 4.124 | 4.144 | (0.605) | (0.585) | 4.559 | 4.579 | (0.170) | (0.150) | 4.984 | 5.004 | 0.255 | 0.275 |
| Nov-01 to Oct-02 | 4.693 | 4.713 | (0.475) | (0.455) | 4.998 | 5.018 | (0.170) | (0.150) | 5.493 | 5.513 | 0.325 | 0.345 |

| | STATION 2 Fixed Price ($C/GJ) BID | Fixed Price OFFER | Basis ($US/MMBtu) BID | Basis OFFER | MALIN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | VENTURA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | NIAGARA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 7.565 | 7.595 | | | 10.905 | 10.925 | | | 5.470 | 5.490 | | | 5.865 | 5.885 | | |
| ROM | 7.885 | 7.915 | | | 9.720 | 9.740 | | | 5.470 | 5.490 | | | 5.890 | 5.910 | | |
| May-01 | 7.850 | 7.880 | (0.230) | (0.210) | 10.599 | 10.619 | 5.040 | 5.060 | 5.574 | 5.594 | 0.015 | 0.035 | 5.879 | 5.899 | 0.320 | 0.340 |
| May-01 to Oct-01 | 8.018 | 8.048 | (0.200) | (0.180) | 10.820 | 10.840 | 5.175 | 5.195 | 5.660 | 5.680 | 0.015 | 0.035 | 5.955 | 5.975 | 0.310 | 0.330 |
| Nov-01 to Mar-02 | 8.515 | 8.545 | 0.010 | 0.030 | 12.065 | 12.085 | 6.290 | 6.310 | 5.945 | 5.965 | 0.170 | 0.190 | 6.350 | 6.370 | 0.575 | 0.595 |
| Apr-02 to Oct-02 | 6.628 | 6.658 | (0.225) | (0.205) | 7.019 | 7.039 | 2.290 | 2.310 | 4.759 | 4.779 | 0.030 | 0.050 | 5.029 | 5.049 | 0.300 | 0.320 |
| Nov-01 to Oct-02 | 7.414 | 7.444 | (0.130) | (0.110) | 9.138 | 9.158 | 3.970 | 3.990 | 5.258 | 5.278 | 0.090 | 0.110 | 5.583 | 5.603 | 0.415 | 0.435 |

| | SUMAS ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SoCAL ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | CHICAGO CITY GATE ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | TRANSCO Z6 ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 5.550 | 5.570 | | | 13.500 | 13.520 | | | 5.635 | 5.655 | | | 6.000 | 6.020 | | |
| ROM | 5.570 | 5.590 | | | 14.620 | 14.640 | | | 5.625 | 5.645 | | | 6.020 | 6.040 | | |
| May-01 | 5.609 | 5.629 | 0.050 | 0.070 | 14.699 | 14.719 | 9.140 | 9.160 | 5.689 | 5.709 | 0.130 | 0.150 | 6.009 | 6.029 | 0.450 | 0.470 |
| May-01 to Oct-01 | 5.710 | 5.730 | 0.065 | 0.085 | 14.685 | 14.705 | 9.040 | 9.060 | 5.780 | 5.800 | 0.135 | 0.155 | 6.150 | 6.170 | 0.505 | 0.525 |
| Nov-01 to Mar-02 | 10.335 | 10.355 | 4.560 | 4.580 | 14.115 | 14.135 | 8.340 | 8.360 | 6.035 | 6.055 | 0.260 | 0.280 | 7.485 | 7.505 | 1.710 | 1.730 |
| Apr-02 to Oct-02 | 4.744 | 4.764 | 0.015 | 0.035 | 8.319 | 8.339 | 3.590 | 3.610 | 4.849 | 4.869 | 0.120 | 0.140 | 5.194 | 5.214 | 0.465 | 0.485 |
| Nov-01 to Oct-02 | 7.088 | 7.108 | 1.920 | 1.940 | 10.748 | 10.768 | 5.580 | 5.600 | 5.348 | 5.368 | 0.180 | 0.200 | 6.153 | 6.173 | 0.985 | 1.005 |

JRT 10/2/00

**CONFIDENTIAL**
Avista Utilities
Gas/Electric Transaction

Date of Transaction: 4-11-01 Reference No. ____________

Transaction Details: Purchase / Sale (Circle) Financial

Delivery Period Nov 1, 2001 thru Oct 31, 2004

Volume 10,000 MMBtu/day

Location ____________

Price Fixed Price $6.7525 (Lock in Malin NGI monthly index)

~~Broker~~ ~~Natsource (Broker)~~ Mirant

Market Conditions: Forward Electric Prices Calendar 2002, 2003 & 2004 heavy load are $191.50, $84.25 & $66 respectively

____________

System Position and Reason for Action (Attach Position Report): The gas to run Coyote has been purchased @ an index price - locking in the gas price fixes the cost of generation significantly below the forward market price of power.

Dispatchability: ____________

____________

____________

Transmission Alternatives: ____________

____________

____________

Building Options: ____________

____________

**CONFIDENTIAL** JRT 10/2/00

Financial and Rate Impacts: Gas prize locked in to fix cost to generate @ Coyote Springs 2 - significantly below forward power prizes.

| Market Quotes: | Broker | Quote |
|---|---|---|
| | Broker | Quote |
| | Broker | Quote |

Completed by: ______________________ Date: ____________________

\$6.7525 fixed prize + \$.15 original purchase over index = \$6.9025

\$6.9025 x 6.9 HR = \$47.63/MW Cost to generate

| Market Prize of Power | HL 2002 | \$191.50 |
|---|---|---|
| | HL 2003 | \$84.25 |
| | HL 2004 | \$66.00 |

(2005)

**CONFIDENTIAL**

## Corporation

Gas Supply

Price Quotation Summary Sheet

PAPER SWAP

Date: 4/11/01 Company: MIRANT THROUGH NATSOURCE ①E

Representative:
(Name) SCOTT THOMPSON MIRANT
(Title) 678 579 3435
(Phone #) VIA PERRY UNDSETH @ NATSOURCE 403 215 5326
(FAX #)

Volume: 10000 MMBtu Price Quoted: $6.7525 /MMBtu

Period: From: Nov 1, 01 To: Oct 31, 04

Type: ☐ Firm ☐ Interruptible

Maximum Take: PAPER MMBtu per ☒ Day ☐ Month

Minimum Take: ______ MMBtu per ☐ Day ☐ Month

Reservation Fee: $______ /MMBtu

Receipt Point: MALIN FIXED for FLOAT SWAP

Pipeline: ☐ Northwest ☐ PGT AVISTA CORP PAYS 6.7525 MIRANT PAYS INDEX (NAT GAS INTEL - MONTHLY)

☐ Accepted ☐ Rejected Date: 4/11/01

OK'D BY KELLY NORWOOD & GARY ELY.

IF ACCEPTED: Date of Contract:

Company Address: SUPPLY FIXED PRICE HEDGE for CSZ

Accounting Contact:
(Name)
(Phone #)
(FAX #)

Wire Transfer Contact:
(Name)
(Phone #)
(FAX #)
Bank:
Account #:
Date of Payment:

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*Avista Utilities*
Position Report
2001-04-09.xls

Indicates positions outside of risk policy limits

| Month | Hrs | Index Purchase (Sale) [a] | Physical Position Long (Short) [b] | Financial Put (Call) Net Delta [c] | Total Position Long (Short) [d] | CT Inc in Phy Fuel Pur | CT Turb. Fuel Not Pur [e] | Physical Open Position [f] | Financial Open Position [g] | Financial Quarter Average | Fin & NG Open Position [h] | Month Short Limit | Month Long Limit | Fin & NG Quarter Average | Quarter Short Limit | Quarter Long Limit | Month | Hrs | Hrs | Impact of $50 Price Increase |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Col (1) | Col (2) | Col (3) | Col (4) Col (2) + Col (3) | Col (5) | Col (6) | Col (7) Col (4) + Col (6) | Col (8) Col (7) - Col (1) | Col (9) Avg Col 8 | Col (10) Col (8) - Col (6) | Col (11) | Col (12) | Col (13) Avg Col 10 | Col (14) | Col (15) | | | | |
| May-01 | HL | (5) | 26 | 0 | 26 | 123 | 58 | 84 | 89 | | 31 | (25) | 125 | | | | May-01 | HL | 416 | $ 1,859,850 |
| May-01 | LL | (5) | 45 | 0 | 45 | 121 | 55 | 100 | 105 | | 50 | (25) | 125 | | | | May-01 | LL | 328 | $ 1,717,850 |
| Jun-01 | HL | (5) | (55) | 0 | (55) | 124 | 0 | (55) | (50) | | (50) | (25) | 125 | | | | Jun-01 | HL | 416 | $ (1,046,450) |
| Jun-01 | LL | (5) | 52 | 0 | 52 | 120 | 0 | 52 | 57 | | 57 | (25) | 125 | | | | Jun-01 | LL | 304 | $ 869,000 |
| Jul-01 | HL | (5) | (6) | 0 | (6) | 150 | 0 | (6) | (1) | | (1) | (75) | 200 | | | | Jul-01 | HL | 400 | $ (11,400) |
| Jul-01 | LL | (5) | 57 | 0 | 57 | 150 | 0 | 57 | 62 | | 62 | (75) | 200 | | | | Jul-01 | LL | 344 | $ 1,060,750 |
| Aug-01 | HL | 5 | (3) | 0 | (3) | 200 | 0 | (3) | (8) | 52 | (8) | (75) | 200 | 52 | (25) | 150 | Aug-01 | HL | 432 | $ (176,750) |
| Aug-01 | LL | 5 | 51 | 0 | 51 | 200 | 0 | 51 | 46 | 73 | 46 | (75) | 200 | 73 | (25) | 150 | Aug-01 | LL | 312 | $ 722,150 |
| Sep-01 | HL | (5) | 159 | 0 | 159 | 208 | 0 | 159 | 164 | | 164 | (75) | 200 | | | | Sep-01 | HL | 384 | $ 3,155,300 |
| Sep-01 | LL | (5) | 107 | 0 | 107 | 208 | 0 | 107 | 112 | | 112 | (75) | 200 | | | | Sep-01 | LL | 336 | $ 1,889,200 |
| Oct-01 | HL | (5) | 7 | 0 | 7 | 208 | 0 | 7 | 12 | | 12 | (150) | 250 | | | | Oct-01 | HL | 432 | $ 250,500 |
| Oct-01 | LL | (5) | 100 | 0 | 100 | 208 | 0 | 100 | 105 | | 105 | (150) | 250 | | | | Oct-01 | LL | 312 | $ 1,633,000 |
| Nov-01 | HL | (5) | 120 | 0 | 120 | 219 | 0 | 120 | 125 | 95 | 125 | (150) | 250 | 95 | (50) | 150 | Nov-01 | HL | 400 | $ 2,496,600 |
| Nov-01 | LL | (5) | 85 | (90) | (4) | 160 | 0 | (4) | 1 | 22 | 1 | (150) | 250 | 22 | (50) | 150 | Nov-01 | LL | 320 | $ 12,400 |
| Dec-01 | HL | (5) | 144 | 0 | 144 | 219 | 0 | 144 | 149 | | 149 | (150) | 250 | | | | Dec-01 | HL | 400 | $ 2,976,600 |
| Dec-01 | LL | (5) | 40 | (85) | (45) | 160 | 0 | (45) | (40) | | (40) | (150) | 250 | | | | Dec-01 | LL | 344 | $ (696,350) |
| Jan-02 | HL | (5) | 106 | 0 | 106 | 99 | 61 | 167 | 172 | | 111 | (150) | 250 | | | | Jan-02 | HL | 416 | $ 3,584,700 |
| Jan-02 | LL | (5) | 113 | (87) | 26 | 99 | 61 | 87 | 92 | | 31 | (150) | 250 | | | | Jan-02 | LL | 328 | $ 1,508,100 |
| Feb-02 | HL | (5) | 97 | 0 | 97 | 99 | 41 | 138 | 143 | 156 | 102 | (150) | 250 | 115 | (50) | 150 | Feb-02 | HL | 384 | $ 2,747,100 |
| Feb-02 | LL | (5) | 163 | (87) | 76 | 99 | 41 | 117 | 122 | 111 | 81 | (150) | 250 | 70 | (50) | 150 | Feb-02 | LL | 288 | $ 1,753,150 |
| Mar-02 | HL | (5) | 127 | 0 | 127 | 99 | 19 | 146 | 151 | | 132 | (150) | 250 | | | | Mar-02 | HL | 416 | $ 3,144,400 |
| Mar-02 | LL | (5) | 180 | (87) | 93 | 99 | 20 | 113 | 118 | | 98 | (150) | 250 | | | | Mar-02 | LL | 328 | $ 1,938,200 |
| Apr-02 | HL | (5) | 147 | (91) | 56 | 99 | 56 | 112 | 117 | | 61 | (150) | 250 | | | | Apr-02 | HL | 416 | $ 2,430,700 |
| Apr-02 | LL | (5) | 144 | (76) | 68 | 99 | 56 | 124 | 129 | | 73 | (150) | 250 | | | | Apr-02 | LL | 304 | $ 1,958,950 |
| May-02 | HL | (5) | 196 | 0 | 196 | 99 | 47 | 243 | 248 | 187 | 201 | (150) | 250 | 153 | (50) | 150 | May-02 | HL | 416 | $ 5,167,200 |
| May-02 | LL | (5) | 173 | 0 | 173 | 99 | 44 | 217 | 222 | 188 | 178 | (150) | 250 | 155 | (50) | 150 | May-02 | LL | 328 | $ 3,643,150 |
| Jun-02 | HL | (5) | 289 | (97) | 192 | 119 | 0 | 192 | 197 | | 197 | (150) | 250 | | | | Jun-02 | HL | 400 | $ 3,941,200 |
| Jun-02 | LL | (5) | 293 | (83) | 209 | 119 | 0 | 209 | 214 | | 214 | (150) | 250 | | | | Jun-02 | LL | 320 | $ 3,431,650 |
| Jul-02 | HL | (5) | 242 | 0 | 242 | 150 | 0 | 242 | 247 | | 247 | (175) | 250 | | | | Jul-02 | HL | 416 | $ 5,127,400 |
| Jul-02 | LL | (5) | 214 | 0 | 214 | 150 | 0 | 214 | 219 | | 219 | (175) | 250 | | | | Jul-02 | LL | 328 | $ 3,591,800 |
| | | | | | | | | | | | | | | | | | Jan-00 | 0 | | |
| Aug-02 | HL | 5 | (52) | 0 | (52) | 260 | 200 | 148 | 143 | 189 | (57) | (175) | 250 | 53 | (75) | 150 | Aug-02 | HL | 432 | $ 3,099,450 |
| Aug-02 | LL | 5 | 245 | 0 | 245 | 260 | 200 | 445 | 440 | 377 | 240 | (175) | 250 | 241 | (75) | 150 | Aug-02 | LL | 312 | $ 6,856,750 |
| Sep-02 | HL | (5) | (37) | 0 | (37) | 265 | 208 | 171 | 176 | | (32) | (175) | 250 | | | | Sep-02 | HL | 384 | $ 3,374,350 |
| Sep-02 | LL | (5) | 260 | 0 | 260 | 265 | 208 | 468 | 473 | | 265 | (175) | 250 | | | | Sep-02 | LL | 336 | $ 7,946,250 |
| Oct-02 | HL | (5) | 87 | 0 | 87 | 265 | 208 | 295 | 300 | | 92 | (175) | 250 | | | | Oct-02 | HL | 432 | $ 6,478,550 |
| Oct-02 | LL | (5) | 264 | 0 | 264 | 265 | 208 | 472 | 477 | | 269 | (175) | 250 | | | | Oct-02 | LL | 312 | $ 7,437,100 |

Footnotes: [a] Index transactions are already included in the total physical position. [b] Physical position. [c] Aggregate physical equivalent (delta) position of options (put and calls). [d] Total position is the combined physical and delta positions. [e] Turbines in this column are available for use, but gas has not been purchased. When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column. [f] Open physical position includes total position and available turbines. [g] Open financial position includes open physical position less any index position. [h] Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased.

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# Avista Utilities

## Physical Surplus-(Deficiency)

2001-04-09.xls

Indicates Changes

| Month | Hours | Native Load | Contract Purchases | Contract Sales | PURPA Contracts | Colstrip | Kettle Falls | NECT | Rathdrum | Coyote Springs | Mid -C Hydro | Clark Fork Hydro | Spokane Hydro | Total Resource | Total Obligation | Physical Surplus/ (Deficiency) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) |
| May-01 | HL | 1,037 | (654) | 820 | (62) | (195) | (26) | (35) | (88) | 0 | (119) | (536) | (170) | (1,884) | 1,858 | 26 |
| May-01 | LL | 830 | (697) | 626 | (62) | (203) | (27) | (33) | (88) | 0 | (65) | (173) | (153) | (1,501) | 1,456 | 45 |
| Jun-01 | HL | 1,016 | (678) | 910 | (31) | (216) | (48) | 0 | (124) | 0 | (118) | (500) | (155) | (1,871) | 1,926 | (55) |
| Jun-01 | LL | 798 | (727) | 595 | (31) | (216) | (48) | 0 | (120) | 0 | (62) | (164) | (77) | (1,445) | 1,393 | 52 |
| Jul-01 | HL | 1,122 | (1,004) | 947 | (62) | (216) | (48) | 0 | (150) | 0 | (128) | (394) | (61) | (2,063) | 2,069 | (6) |
| Jul-01 | LL | 867 | (768) | 594 | (62) | (216) | (48) | 0 | (150) | 0 | (72) | (148) | (53) | (1,518) | 1,461 | 57 |
| Aug-01 | HL | 1,155 | (865) | 618 | (62) | (216) | (48) | (50) | (150) | 0 | (110) | (223) | (47) | (1,770) | 1,774 | (3) |
| Aug-01 | LL | 862 | (587) | 359 | (62) | (216) | (48) | (50) | (150) | 0 | (58) | (80) | (21) | (1,272) | 1,221 | 51 |
| Sep-01 | HL | 1,016 | (855) | 531 | (54) | (216) | (48) | (52) | (156) | 0 | (88) | (172) | (66) | (1,706) | 1,547 | 159 |
| Sep-01 | LL | 809 | (567) | 345 | (54) | (216) | (48) | (52) | (156) | 0 | (50) | (80) | (38) | (1,261) | 1,154 | 107 |
| Oct-01 | HL | 1,045 | (508) | 357 | (62) | (216) | (48) | (52) | (156) | 0 | (91) | (199) | (77) | (1,409) | 1,402 | 7 |
| Oct-01 | LL | 829 | (455) | 234 | (62) | (216) | (48) | (52) | (156) | 0 | (47) | (75) | (51) | (1,163) | 1,063 | 100 |
| Nov-01 | HL | 1,167 | (592) | 356 | (62) | (216) | (48) | (59) | (160) | 0 | (106) | (282) | (118) | (1,643) | 1,523 | 120 |
| Nov-01 | LL | 954 | (568) | 241 | (62) | (216) | (48) | 0 | (160) | 0 | (59) | (103) | (65) | (1,280) | 1,195 | 85 |
| Dec-01 | HL | 1,256 | (613) | 352 | (62) | (216) | (48) | (59) | (160) | 0 | (128) | (310) | (157) | (1,752) | 1,609 | 144 |
| Dec-01 | LL | 1,038 | (565) | 241 | (62) | (216) | (48) | 0 | (160) | 0 | (72) | (117) | (78) | (1,319) | 1,279 | 40 |
| Jan-02 | HL | 1,265 | (415) | 126 | (62) | (216) | (48) | 0 | (99) | 0 | (179) | (310) | (169) | (1,498) | 1,391 | 106 |
| Jan-02 | LL | 1,043 | (473) | 26 | (62) | (216) | (48) | 0 | (99) | 0 | (98) | (108) | (77) | (1,181) | 1,068 | 113 |
| Feb-02 | HL | 1,204 | (413) | 122 | (62) | (216) | (48) | 0 | (99) | 0 | (152) | (255) | (178) | (1,423) | 1,326 | 97 |
| Feb-02 | LL | 1,000 | (476) | 20 | (62) | (216) | (48) | 0 | (99) | 0 | (81) | (90) | (111) | (1,183) | 1,020 | 163 |
| Mar-02 | HL | 1,112 | (349) | 119 | (62) | (216) | (48) | 0 | (99) | 0 | (126) | (280) | (178) | (1,359) | 1,231 | 127 |
| Mar-02 | LL | 927 | (410) | 20 | (62) | (216) | (48) | 0 | (99) | 0 | (69) | (101) | (123) | (1,127) | 947 | 180 |
| Apr-02 | HL | 1,068 | (100) | 123 | (62) | (216) | (48) | 0 | (99) | 0 | (103) | (492) | (217) | (1,338) | 1,191 | 147 |
| Apr-02 | LL | 866 | (215) | 20 | (62) | (216) | (48) | 0 | (99) | 0 | (54) | (175) | (162) | (1,030) | 886 | 144 |
| May-02 | HL | 1,060 | (58) | 123 | (62) | (108) | (28) | 0 | (99) | 0 | (114) | (740) | (170) | (1,379) | 1,183 | 196 |
| May-02 | LL | 854 | (150) | 26 | (62) | (108) | (25) | 0 | (99) | 0 | (62) | (405) | (142) | (1,053) | 880 | 173 |
| Jun-02 | HL | 1,038 | (58) | 147 | (31) | (151) | (48) | 0 | (119) | 0 | (139) | (750) | (178) | (1,474) | 1,185 | 289 |
| Jun-02 | LL | 827 | (150) | 20 | (31) | (151) | (48) | 0 | (119) | 0 | (77) | (459) | (105) | (1,140) | 847 | 293 |
| Jul-02 | HL | 1,158 | (258) | 157 | (62) | (216) | (48) | 0 | (150) | 0 | (124) | (570) | (128) | (1,556) | 1,315 | 242 |
| Jul-02 | LL | 894 | (350) | 27 | (62) | (216) | (48) | 0 | (150) | 0 | (67) | (175) | (67) | (1,135) | 921 | 214 |
| Aug-02 | HL | 1,175 | (268) | 262 | (62) | (216) | (48) | 0 | 0 | (260) | (129) | (320) | (83) | (1,386) | 1,437 | (52) |
| Aug-02 | LL | 882 | (365) | 20 | (62) | (216) | (48) | 0 | 0 | (260) | (67) | (100) | (29) | (1,147) | 902 | 245 |
| Sep-02 | HL | 1,040 | (258) | 242 | (54) | (216) | (48) | 0 | 0 | (265) | (105) | (199) | (100) | (1,245) | 1,282 | (37) |
| Sep-02 | LL | 830 | (345) | 33 | (54) | (216) | (48) | 0 | 0 | (265) | (60) | (88) | (48) | (1,124) | 864 | 260 |
| Oct-02 | HL | 1,069 | (258) | 121 | (62) | (216) | (48) | 0 | 0 | (265) | (106) | (202) | (119) | (1,276) | 1,189 | 87 |

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# Enron Ca. .da Corp.
## April 12, 2001

| AECO / NIT ($CND/GJ) | | Fixed Price ($CND/GJ) BID | Fixed Price ($CND/GJ) OFFER | Basis ($US /MMBtu) BID | Basis ($US /MMBtu) OFFER | Aeco/Empress Transport BID | Aeco/Empress Transport OFFER |
|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 7.638 | 7.648 | | | | |
| ROM | | 7.545 | 7.555 | | | - | 0.015 |
| May-01 | (Physical) | 7.560 | 7.570 | (0.287) | (0.267) | - | 0.025 |
| May-01 to Oct-01 | | 7.711 | 7.731 | (0.275) | (0.255) | (0.010) | 0.010 |
| Nov-01 to Mar-02 | | 8.050 | 8.070 | (0.195) | (0.175) | 0.140 | 0.160 |
| Apr-02 to Oct-02 | | 6.427 | 6.447 | (0.300) | (0.280) | 0.140 | 0.160 |
| Nov-01 to Oct-02 | | 7.109 | 7.129 | (0.255) | (0.235) | 0.140 | 0.160 |


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**MAIN FAX (403) 974-6706**

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| Mike Cowan | 974-6712 | Jon McKay | 974-6733 |
| Derek Davies | 974-6793 | Rob Milnthorp | 974-6714 |
| Dean Drozdiak | 974-6751 | Cynlia Di Stefano | 974-6750 |
| | | Grant Oh | 974-6778 |


| | | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE |
|---|---|---|---|---|
| Cash | (Physical) | 1.563 | 5.470 | |
| ROM | | | 5.360 | |
| May-01 | | | | 5.385 |
| May-01 to Oct-01 | | | | 5.480 |
| Nov-01 to Mar-02 | | | | 5.629 |
| Apr-02 to Oct-02 | | | | 4.636 |
| Nov-01 to Oct-02 | | | | 5.052 |

| | ROCKIES ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SAN JUAN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | DAWN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 5.105 | 5.125 | | | | | | | 5.765 | 5.785 | | |
| ROM | 4.700 | 4.720 | | | 4.850 | 4.870 | | | 5.690 | 5.710 | | |
| May-01 | 4.565 | 4.585 | (0.820) | (0.800) | 4.860 | 4.880 | (0.525) | (0.505) | 5.665 | 5.685 | 0.280 | 0.30[illegible] |
| May-01 to Oct-01 | 4.585 | 4.605 | (0.895) | (0.875) | 5.010 | 5.030 | (0.470) | (0.450) | 5.750 | 5.770 | 0.270 | 0.29[illegible] |
| Nov-01 to Mar-02 | 5.339 | 5.359 | (0.290) | (0.270) | 5.449 | 5.469 | (0.180) | (0.160) | 6.034 | 6.054 | 0.405 | 0.42[illegible] |
| Apr-02 to Oct-02 | 4.026 | 4.046 | (0.610) | (0.590) | 4.456 | 4.476 | (0.180) | (0.160) | 4.886 | 4.906 | 0.250 | 0.27[illegible] |
| Nov-01 to Oct-02 | 4.577 | 4.597 | (0.475) | (0.455) | 4.872 | 4.892 | (0.180) | (0.160) | 5.367 | 5.387 | 0.315 | 0.33[illegible] |

| | STATION 2 Fixed Price ($C/GJ) BID | Fixed Price OFFER | Basis ($US/MMBtu) BID | Basis OFFER | MALIN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | VENTURA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | NIAGARA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 7.650 | 7.680 | | | 11.385 | 11.405 | | | 5.425 | 5.445 | | | 5.795 | 5.815 | | |
| ROM | 7.735 | 7.765 | | | 9.550 | 9.570 | | | 5.300 | 5.320 | | | 5.710 | 5.730 | | |
| May-01 | 7.597 | 7.627 | (0.255) | (0.235) | 10.075 | 10.095 | 4.690 | 4.710 | 5.395 | 5.415 | 0.010 | 0.030 | 5.700 | 5.720 | 0.315 | 0.335 |
| May-01 to Oct-01 | 7.750 | 7.780 | (0.245) | (0.225) | 10.255 | 10.275 | 4.775 | 4.795 | 5.490 | 5.510 | 0.010 | 0.030 | 5.780 | 5.800 | 0.300 | 0.320 |
| Nov-01 to Mar-02 | 8.333 | 8.363 | - | 0.020 | 11.069 | 11.089 | 5.440 | 5.460 | 5.799 | 5.819 | 0.170 | 0.190 | 6.194 | 6.214 | 0.565 | 0.585 |
| Apr-02 to Oct-02 | 6.526 | 6.556 | (0.230) | (0.210) | 6.646 | 6.666 | 2.010 | 2.030 | 4.666 | 4.686 | 0.030 | 0.050 | 4.931 | 4.951 | 0.295 | 0.315 |
| Nov-01 to Oct-02 | 7.282 | 7.312 | (0.135) | (0.115) | 8.502 | 8.522 | 3.450 | 3.470 | 5.142 | 5.162 | 0.090 | 0.110 | 5.462 | 5.482 | 0.410 | 0.430 |

| | SUMAS ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SoCAL ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | CHICAGO CITY GATE ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | TRANSCO Z6 ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 5.500 | 5.520 | | | 14.225 | 14.245 | | | 5.570 | 5.590 | | | 5.875 | 5.895 | | |
| ROM | 5.340 | 5.360 | | | 14.600 | 14.620 | | | 5.455 | 5.475 | | | 5.780 | 5.800 | | |
| May-01 | 5.435 | 5.455 | 0.050 | 0.070 | 14.175 | 14.195 | 8.790 | 8.810 | 5.515 | 5.535 | 0.130 | 0.150 | 5.815 | 5.835 | 0.430 | 0.450 |
| May-01 to Oct-01 | 5.545 | 5.565 | 0.065 | 0.085 | 14.125 | 14.145 | 8.645 | 8.665 | 5.615 | 5.635 | 0.135 | 0.155 | 5.980 | 6.000 | 0.500 | 0.520 |
| Nov-01 to Mar-02 | 9.799 | 9.819 | 4.170 | 4.190 | 13.369 | 13.389 | 7.740 | 7.760 | 5.879 | 5.899 | 0.250 | 0.270 | 7.339 | 7.359 | 1.710 | 1.730 |
| Apr-02 to Oct-02 | 4.651 | 4.671 | 0.015 | 0.035 | 7.901 | 7.921 | 3.265 | 3.285 | 4.751 | 4.771 | 0.115 | 0.135 | 5.101 | 5.121 | 0.465 | 0.485 |
| Nov-01 to Oct-02 | 6.807 | 6.827 | 1.755 | 1.775 | 10.192 | 10.212 | 5.140 | 5.160 | 5.222 | 5.242 | 0.170 | 0.190 | 6.037 | 6.057 | 0.985 | 1.005 |

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# Enron Ca...da Corp.
## April 11, 2001

| AECO / NIT ($CND/GJ) | | Fixed Price ($CND/GJ) BID | Fixed Price ($CND/GJ) OFFER | Basis ($US /MMBtu) BID | Basis ($US /MMBtu) OFFER | Aeco/Empress Transport BID | Aeco/Empress Transport OFFER |
|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 7.790 | 7.800 | | | | |
| ROM | | 7.775 | 7.785 | | | - | 0.015 |
| May-01 | (Physical) | 7.810 | 7.820 | (0.264) | (0.244) | - | 0.025 |
| May-01 to Oct-01 | | 7.920 | 7.940 | (0.270) | (0.250) | (0.010) | 0.010 |
| Nov-01 to Mar-02 | | 8.225 | 8.245 | (0.190) | (0.170) | 0.140 | 0.160 |
| Apr-02 to Oct-02 | | 6.530 | 6.550 | (0.295) | (0.275) | 0.140 | 0.160 |
| Nov-01 to Oct-02 | | 7.242 | 7.262 | (0.250) | (0.230) | 0.140 | 0.160 |


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|---|---|---|---|
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| Mike Cowan | 974-6712 | Jon McKay | 974-6733 |
| Derek Davies | 974-6793 | Rob Milnthorp | 974-6714 |
| John Disturnal | 974-6772 | Cyntia Di Stefano | 974-6750 |
| Dean Drozdiak | 974-6751 | Grant Oh | 974-6778 |


| | | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE |
|---|---|---|---|---|
| Cash | (Physical) | 1.556 | 5.545 | |
| ROM | | | 5.530 | |
| May-01 | | | | 5.559 |
| May-01 to Oct-01 | | | | 5.645 |
| Nov-01 to Mar-02 | | | | 5.775 |
| Apr-02 to Oct-02 | | | | 4.729 |
| Nov-01 to Oct-02 | | | | 5.168 |

| | ROCKIES ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SAN JUAN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | DAWN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 4.965 | 4.985 | | | 4.980 | 5.000 | | | 5.855 | 5.875 | | |
| ROM | 4.670 | 4.690 | | | 4.870 | 4.890 | | | 5.870 | 5.890 | | |
| May-01 | 4.689 | 4.709 | (0.870) | (0.850) | 4.944 | 4.964 | (0.615) | (0.595) | 5.849 | 5.869 | 0.290 | 0.310 |
| May-01 to Oct-01 | 4.710 | 4.730 | (0.935) | (0.915) | 5.125 | 5.145 | (0.520) | (0.500) | 5.925 | 5.945 | 0.280 | 0.300 |
| Nov-01 to Mar-02 | 5.485 | 5.505 | (0.290) | (0.270) | 5.605 | 5.625 | (0.170) | (0.150) | 6.190 | 6.210 | 0.415 | 0.435 |
| Apr-02 to Oct-02 | 4.124 | 4.144 | (0.605) | (0.585) | 4.559 | 4.579 | (0.170) | (0.150) | 4.984 | 5.004 | 0.255 | 0.275 |
| Nov-01 to Oct-02 | 4.693 | 4.713 | (0.475) | (0.455) | 4.998 | 5.018 | (0.170) | (0.150) | 5.493 | 5.513 | 0.325 | 0.345 |

| | STATION 2 Fixed Price ($C/GJ) BID | Fixed Price OFFER | Basis ($US/MMBtu) BID | Basis OFFER | MALIN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | VENTURA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | NIAGARA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 7.565 | 7.595 | | | 10.905 | 10.925 | | | 5.470 | 5.490 | | | 5.865 | 5.885 | | |
| ROM | 7.885 | 7.915 | | | 9.720 | 9.740 | | | 5.470 | 5.490 | | | 5.890 | 5.910 | | |
| May-01 | 7.850 | 7.880 | (0.230) | (0.210) | 10.599 | 10.619 | 5.040 | 5.060 | 5.574 | 5.594 | 0.015 | 0.035 | 5.879 | 5.899 | 0.320 | 0.340 |
| May-01 to Oct-01 | 8.018 | 8.048 | (0.200) | (0.180) | 10.820 | 10.840 | 5.175 | 5.195 | 5.660 | 5.680 | 0.015 | 0.035 | 5.955 | 5.975 | 0.310 | 0.330 |
| Nov-01 to Mar-02 | 8.515 | 8.545 | 0.010 | 0.030 | 12.065 | 12.085 | 6.290 | 6.310 | 5.945 | 5.965 | 0.170 | 0.190 | 6.350 | 6.370 | 0.575 | 0.595 |
| Apr-02 to Oct-02 | 6.628 | 6.658 | (0.225) | (0.205) | 7.019 | 7.039 | 2.290 | 2.310 | 4.759 | 4.779 | 0.030 | 0.050 | 5.029 | 5.049 | 0.300 | 0.320 |
| Nov-01 to Oct-02 | 7.414 | 7.444 | (0.130) | (0.110) | 9.138 | 9.158 | 3.970 | 3.990 1yr | 5.258 | 5.278 | 0.090 | 0.110 | 5.583 | 5.603 | 0.415 | 0.435 |

| | SUMAS ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SoCAL ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | CHICAGO CITY GATE ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | TRANSCO Z6 ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 5.550 | 5.570 | | | 13.500 | 13.520 | | | 5.635 | 5.655 | | | 6.000 | 6.020 | | |
| ROM | 5.570 | 5.590 | | | 14.620 | 14.640 | | | 5.625 | 5.645 | | | 6.020 | 6.040 | | |
| May-01 | 5.609 | 5.629 | 0.050 | 0.070 | 14.699 | 14.719 | 9.140 | 9.160 | 5.689 | 5.709 | 0.130 | 0.150 | 6.009 | 6.029 | 0.450 | 0.470 |
| May-01 to Oct-01 | 5.710 | 5.730 | 0.065 | 0.085 | 14.685 | 14.705 | 9.040 | 9.060 | 5.780 | 5.800 | 0.135 | 0.155 | 6.150 | 6.170 | 0.505 | 0.525 |
| Nov-01 to Mar-02 | 10.335 | 10.355 | 4.560 | 4.580 | 14.115 | 14.135 | 8.340 | 8.360 | 6.035 | 6.055 | 0.260 | 0.280 | 7.485 | 7.505 | 1.710 | 1.730 |
| Apr-02 to Oct-02 | 4.744 | 4.764 | 0.015 | 0.035 | 8.319 | 8.339 | 3.590 | 3.610 | 4.849 | 4.869 | 0.120 | 0.140 | 5.194 | 5.214 | 0.465 | 0.485 |
| Nov-01 to Oct-02 | 7.088 | 7.108 | 1.920 | 1.940 | 10.748 | 10.768 | 5.580 | 5.600 | 5.348 | 5.368 | 0.180 | 0.200 | 6.153 | 6.173 | 0.985 | 1.005 |

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DRAFT
JRT 10/2/00

## Avista Utilities
## Gas/Electric Transaction

Date of Transaction: 5-2-01  Reference No. ____________

Transaction Details: Purchase / Sale (Circle)  Financial

Delivery Period Nov 1, 2001 thru Oct 31, 2004

Volume 10,000 MMBtu/day

Location ____________

Price Fixed Price $5.85 (Lock in Malin NGI monthly index

Broker Natsource (Broker) BP Corporation North America Inc.

Market Conditions: Forward Electric Prices Calendar 2002, 2003 & 20 heavy load are $150.50, 70.00 & $58.00 respectively.

System Position and Reason for Action (Attach Position Report): The gas to run Coyote has been purchased @ an index price - locking in the gas prices fixes the cost of generation significantly below the forward market price of power

Dispatchability: ____________

Transmission Alternatives: ____________

Building Options: ____________

DRAFT
JRT 10/2/00

# CONFIDENTIAL

Financial and Rate Impacts: Gas price locked in to fix cost to generate @ Coyote Springs 2 - significantly below forward power price

Market Quotes: Broker ____________ Quote ______________

Broker ____________ Quote ______________

Broker ____________ Quote ______________

Completed by: ______________________ Date: ____________________

$5.85 fixed price + $.15 original purchase over index = $5.90

$5.90 X 6.9 HR = $40.71/MW cost to generate

Market Price of Power HL 2002 $150.00

HL 2003 $70.00

HL 2004 $58.00

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2008

## Corporation

Gas Supply

Price Quotation Summary Sheet

PAPER SWAP ~~FIXED~~ FIXED for FLOAT

Date: 5-2-01 Company: BP ENERGY VIA NATSOURCE

Representative:

(Name) DAVID HOUGHTON

(Title) VIA PERRY LINDSETH @ NATSOURCE

(Phone #) (403) 215-5300

(FAX #)

Volume: 10,000 MMBtu Price Quoted: $ 5.85 /MMBtu FIXED

Period: From: NOV 01, '01 ~~Thru~~ To: OCT 31, '04

Type: [X] Firm [ ] Interruptible

Maximum Take: PAPER MMBtu per [X] Day [ ] Month

Minimum Take: ______ MMBtu per [ ] Day [ ] Month

Reservation Fee: $ ______ /MMBtu

Receipt Point: MALIN FIXED for FLOAT SWAP

Pipeline: [ ] Northwest [X] PGT

AVISTA PAYS 5.85
BP PAYS INDEX

[X] Accepted [ ] Rejected Date: 5-2-01

IF ACCEPTED: Date of Contract: BASED ON PRE AUTHORIZATION FROM GARY ELY.

Company Address:

Accounting Contact: (Name)

(Phone #)

(FAX #)

Wire Transfer Contact: (Name)

(Phone #)

(FAX #)

Bank:

Account #:

Date of Payment:

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CONFIDENTIAL: For Internal Use Only

*Avista Utilities*
Position Report
2001-05-01.xls

Indicates positions outside of risk policy limits

| Month | Hrs | Index Purchase (Sale) [a] | Physical Position Long (Short) [b] | Financial Put (Call) Net Delta [c] | Total Position Long (Short) [d] | CT Inc in Phy Fuel Pur | CT Turb. Fuel Not Pur [e] | Physical Open Position [f] | Financial Open Position [g] | Financial Quarter Average | Fin & NG Open Position [h] | Month Short Limit | Month Long Limit | Fin & NG Quarter Average | Quarter Short Limit | Quarter Long Limit | Month | Hrs | Hrs | Impact of $50 Price Increase |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Col (1) | Col (2) | Col (3) | Col (4) Col (2) + Col (3) | Col (5) | Col (6) | Col (7) Col (4) + Col (6) | Col (8) Col (7) - Col (1) | Col (9) Avg Col 8 | Col (10) Col (8) - Col (6) | Col (11) | Col (12) | Col (13) Avg Col 10 | Col (14) | Col (15) | | | | |
| Jun-01 | HL | (5) | (30) | 0 | (30) | 124 | 0 | (30) | (25) | | (25) | (25) | 125 | | | | Jun-01 | HL | 416 | $ (526,450) |
| Jun-01 | LL | (5) | 52 | 0 | 52 | 120 | 0 | 52 | 57 | | 57 | (25) | 125 | | | | Jun-01 | LL | 304 | $ 869,000 |
| Jul-01 | HL | (5) | (30) | 0 | (30) | 150 | 0 | (30) | (25) | | (25) | (75) | 200 | | | | Jul-01 | HL | 400 | $ (509,150) |
| Jul-01 | LL | (5) | 16 | 0 | 16 | 150 | 0 | 16 | 21 | | 21 | (75) | 200 | | | | Jul-01 | LL | 344 | $ 364,950 |
| Aug-01 | HL | 5 | (21) | 0 | (21) | 200 | 0 | (21) | (26) | 5 | (26) | (75) | 200 | 5 | (25) | 150 | Aug-01 | HL | 432 | $ (565,750) |
| Aug-01 | LL | 5 | 46 | 0 | 46 | 200 | 0 | 46 | 41 | 57 | 41 | (75) | 200 | 57 | (25) | 150 | Aug-01 | LL | 312 | $ 641,400 |
| Sep-01 | HL | (5) | 63 | 0 | 63 | 208 | 0 | 63 | 68 | | 68 | (75) | 200 | | | | Sep-01 | HL | 384 | $ 1,298,200 |
| Sep-01 | LL | (5) | 103 | 0 | 103 | 208 | 0 | 103 | 108 | | 108 | (75) | 200 | | | | Sep-01 | LL | 336 | $ 1,810,800 |
| Oct-01 | HL | (5) | (17) | 0 | (17) | 208 | 0 | (17) | (12) | | (12) | (150) | 250 | | | | Oct-01 | HL | 432 | $ (255,750) |
| Oct-01 | LL | (5) | 101 | 0 | 101 | 208 | 0 | 101 | 106 | | 106 | (150) | 250 | | | | Oct-01 | LL | 312 | $ 1,650,400 |
| Nov-01 | HL | (5) | 96 | 0 | 96 | 219 | 0 | 96 | 101 | 71 | 101 | (150) | 250 | 71 | (50) | 150 | Nov-01 | HL | 400 | $ 2,016,600 |
| Nov-01 | LL | (5) | 86 | (88) | (2) | 160 | 0 | (2) | 3 | 26 | 3 | (150) | 250 | 26 | (50) | 150 | Nov-01 | LL | 320 | $ 47,600 |
| Dec-01 | HL | (5) | 120 | 0 | 120 | 219 | 0 | 120 | 125 | | 125 | (150) | 250 | | | | Dec-01 | HL | 400 | $ 2,496,600 |
| Dec-01 | LL | (5) | 41 | (76) | (35) | 160 | 0 | (35) | (30) | | (30) | (150) | 250 | | | | Dec-01 | LL | 344 | $ (523,550) |
| Jan-02 | HL | (5) | 107 | 0 | 107 | 99 | 61 | 168 | 173 | | 112 | (150) | 250 | | | | Jan-02 | HL | 416 | $ 3,605,500 |
| Jan-02 | LL | (5) | 114 | (67) | 47 | 99 | 61 | 108 | 113 | | 52 | (150) | 250 | | | | Jan-02 | LL | 328 | $ 1,855,300 |
| Feb-02 | HL | (5) | 98 | 0 | 98 | 99 | 41 | 139 | 144 | 157 | 103 | (150) | 250 | 116 | (50) | 150 | Feb-02 | HL | 384 | $ 2,766,300 |
| Feb-02 | LL | (5) | 164 | (80) | 84 | 99 | 41 | 125 | 130 | 124 | 89 | (150) | 250 | 83 | (50) | 150 | Feb-02 | LL | 288 | $ 1,877,550 |
| Mar-02 | HL | (5) | 128 | 0 | 128 | 99 | 19 | 147 | 152 | | 133 | (150) | 250 | | | | Mar-02 | HL | 416 | $ 3,165,200 |
| Mar-02 | LL | (5) | 185 | (82) | 102 | 99 | 20 | 122 | 127 | | 107 | (150) | 250 | | | | Mar-02 | LL | 328 | $ 2,086,900 |
| Apr-02 | HL | (5) | 172 | (91) | 81 | 99 | 56 | 137 | 142 | | 86 | (150) | 250 | | | | Apr-02 | HL | 416 | $ 2,951,550 |
| Apr-02 | LL | (5) | 172 | (47) | 126 | 99 | 56 | 182 | 187 | | 131 | (150) | 250 | | | | Apr-02 | LL | 304 | $ 2,839,700 |
| May-02 | HL | (5) | 197 | 0 | 197 | 99 | 47 | 244 | 249 | 196 | 202 | (150) | 250 | 162 | (50) | 150 | May-02 | HL | 416 | $ 5,188,000 |
| May-02 | LL | (5) | 174 | 0 | 174 | 99 | 44 | 218 | 223 | 213 | 179 | (150) | 250 | 179 | (50) | 150 | May-02 | LL | 328 | $ 3,659,550 |
| Jun-02 | HL | (5) | 290 | (97) | 193 | 119 | 0 | 193 | 198 | | 198 | (150) | 250 | | | | Jun-02 | HL | 400 | $ 3,961,200 |
| Jun-02 | LL | (5) | 294 | (70) | 223 | 119 | 0 | 223 | 228 | | 228 | (150) | 250 | | | | Jun-02 | LL | 320 | $ 3,652,450 |
| Jul-02 | HL | (5) | 243 | 0 | 243 | 150 | 0 | 243 | 248 | | 248 | (175) | 250 | | | | Jul-02 | HL | 416 | $ 5,148,200 |
| Jul-02 | LL | (5) | 215 | 0 | 215 | 150 | 0 | 215 | 220 | | 220 | (175) | 250 | | | | Jul-02 | LL | 328 | $ 3,608,200 |
| Aug-02 | HL | 5 | (51) | 0 | (51) | 260 | 200 | 149 | 144 | 190 | (56) | (175) | 250 | 54 | (75) | 150 | Aug-02 | HL | 432 | $ 3,121,050 |
| Aug-02 | LL | 5 | 246 | 0 | 246 | 260 | 200 | 446 | 441 | 378 | 241 | (175) | 250 | 242 | (75) | 150 | Aug-02 | LL | 312 | $ 6,872,350 |
| | | | | | | | | | | | | | | | | | Jan-00 | 0 | | |
| Sep-02 | HL | (5) | (36) | 0 | (36) | 265 | 208 | 172 | 177 | | (31) | (175) | 250 | | | | Sep-02 | HL | 384 | $ 3,393,550 |
| Sep-02 | LL | (5) | 261 | 0 | 261 | 265 | 208 | 469 | 474 | | 266 | (175) | 250 | | | | Sep-02 | LL | 336 | $ 7,963,050 |
| Oct-02 | HL | (5) | 88 | 0 | 88 | 265 | 208 | 296 | 301 | | 93 | (175) | 250 | | | | Oct-02 | HL | 432 | $ 6,500,150 |
| Oct-02 | LL | (5) | 265 | 0 | 265 | 265 | 208 | 473 | 478 | | 270 | (175) | 250 | | | | Oct-02 | LL | 312 | $ 7,452,700 |
| Nov-02 | HL | (5) | 248 | 0 | 248 | 270 | 218 | 466 | 471 | | 253 | (175) | 250 | | 0 | 0 | Nov-02 | HL | 400 | $ 9,421,100 |
| Nov-02 | LL | (5) | 325 | (48) | 277 | 270 | 160 | 437 | 442 | | 282 | (175) | 250 | | 0 | 0 | Nov-02 | LL | 320 | $ 7,068,750 |

Footnotes: [a] Index transactions are already included in the total physical position. [b] Physical position. [c] Aggregate physical equivalent (delta) position of options (put and calls). [d] Total position is the combined physical and delta positions. [e] Turbines in this column are available for use, but gas has not been purchased. When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column. [f] Open physical position includes total position and available turbines. [g] Open financial position includes open physical position less any index position. [h] Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased. At its meeting on April 10, 2001, the Risk Management Committee suspended the cure date for the positions in Q2 02, Q3 02, Sep 02, and Oct 02 which are longer than the long limits. These positions will be re-evaluated on a monthly basis by the Risk Management Committee.

# Avista Utilities

## Physical Surplus-(Deficiency)

2001-05-01.xls

Indicates Changes

| Month | Hours | Native Load | Contract Purchases | Contract Sales | PURPA Contracts | Colstrip | Kettle Falls | NECT | Rathdrum | Coyote Springs | Mid -C Hydro | Clark Fork Hydro | Spokane Hydro | Total Resource | Total Obligation | Physical Surplus/ (Deficiency) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) |
| Jun-01 | HL | 1,016 | (703) | 910 | (31) | (216) | (48) | 0 | (124) | 0 | (118) | (500) | (155) | (1,896) | 1,926 | (30) |
| Jun-01 | LL | 798 | (727) | 595 | (31) | (216) | (48) | 0 | (120) | 0 | (62) | (164) | (77) | (1,445) | 1,393 | 52 |
| Jul-01 | HL | 1,122 | (1,154) | 947 | (62) | (216) | (48) | 0 | (150) | 0 | (128) | (219) | (61) | (2,039) | 2,069 | (30) |
| Jul-01 | LL | 867 | (768) | 594 | (62) | (216) | (48) | 0 | (150) | 0 | (72) | (108) | (53) | (1,477) | 1,461 | 16 |
| Aug-01 | HL | 1,155 | (890) | 621 | (62) | (216) | (48) | (50) | (150) | 0 | (110) | (182) | (47) | (1,755) | 1,776 | (21) |
| Aug-01 | LL | 862 | (587) | 362 | (62) | (216) | (48) | (50) | (150) | 0 | (58) | (77) | (21) | (1,270) | 1,224 | 46 |
| Sep-01 | HL | 1,016 | (880) | 641 | (54) | (216) | (48) | (52) | (156) | 0 | (88) | (160) | (66) | (1,720) | 1,657 | 63 |
| Sep-01 | LL | 809 | (567) | 345 | (54) | (216) | (48) | (52) | (156) | 0 | (50) | (75) | (38) | (1,257) | 1,154 | 103 |
| Oct-01 | HL | 1,045 | (509) | 382 | (62) | (216) | (48) | (52) | (156) | 0 | (91) | (200) | (77) | (1,410) | 1,427 | (17) |
| Oct-01 | LL | 829 | (456) | 234 | (62) | (216) | (48) | (52) | (156) | 0 | (47) | (75) | (51) | (1,164) | 1,063 | 101 |
| Nov-01 | HL | 1,167 | (593) | 381 | (62) | (216) | (48) | (59) | (160) | 0 | (106) | (282) | (118) | (1,644) | 1,548 | 96 |
| Nov-01 | LL | 954 | (569) | 241 | (62) | (216) | (48) | 0 | (160) | 0 | (59) | (103) | (65) | (1,281) | 1,195 | 86 |
| Dec-01 | HL | 1,256 | (614) | 377 | (62) | (216) | (48) | (59) | (160) | 0 | (128) | (310) | (157) | (1,753) | 1,634 | 120 |
| Dec-01 | LL | 1,038 | (566) | 241 | (62) | (216) | (48) | 0 | (160) | 0 | (72) | (117) | (78) | (1,320) | 1,279 | 41 |
| Jan-02 | HL | 1,265 | (416) | 126 | (62) | (216) | (48) | 0 | (99) | 0 | (179) | (310) | (169) | (1,499) | 1,391 | 107 |
| Jan-02 | LL | 1,043 | (474) | 26 | (62) | (216) | (48) | 0 | (99) | 0 | (98) | (108) | (77) | (1,182) | 1,068 | 114 |
| Feb-02 | HL | 1,204 | (414) | 122 | (62) | (216) | (48) | 0 | (99) | 0 | (152) | (255) | (178) | (1,424) | 1,326 | 98 |
| Feb-02 | LL | 1,000 | (477) | 20 | (62) | (216) | (48) | 0 | (99) | 0 | (81) | (90) | (111) | (1,184) | 1,020 | 164 |
| Mar-02 | HL | 1,112 | (350) | 119 | (62) | (216) | (48) | 0 | (99) | 0 | (126) | (280) | (178) | (1,360) | 1,231 | 128 |
| Mar-02 | LL | 923 | (411) | 20 | (62) | (216) | (48) | 0 | (99) | 0 | (69) | (101) | (123) | (1,128) | 943 | 185 |
| Apr-02 | HL | 1,043 | (101) | 123 | (62) | (216) | (48) | 0 | (99) | 0 | (103) | (492) | (217) | (1,339) | 1,167 | 172 |
| Apr-02 | LL | 838 | (216) | 20 | (62) | (216) | (48) | 0 | (99) | 0 | (54) | (175) | (162) | (1,031) | 858 | 172 |
| May-02 | HL | 1,060 | (59) | 123 | (62) | (108) | (28) | 0 | (99) | 0 | (114) | (740) | (170) | (1,380) | 1,183 | 197 |
| May-02 | LL | 854 | (151) | 26 | (62) | (108) | (25) | 0 | (99) | 0 | (62) | (405) | (142) | (1,054) | 880 | 174 |
| Jun-02 | HL | 1,038 | (59) | 147 | (31) | (151) | (48) | 0 | (119) | 0 | (139) | (750) | (178) | (1,475) | 1,185 | 290 |
| Jun-02 | LL | 827 | (151) | 20 | (31) | (151) | (48) | 0 | (119) | 0 | (77) | (459) | (105) | (1,141) | 847 | 294 |
| Jul-02 | HL | 1,158 | (259) | 157 | (62) | (216) | (48) | 0 | (150) | 0 | (124) | (570) | (128) | (1,557) | 1,315 | 243 |
| Jul-02 | LL | 894 | (351) | 27 | (62) | (216) | (48) | 0 | (150) | 0 | (67) | (175) | (67) | (1,136) | 921 | 215 |
| Aug-02 | HL | 1,175 | (269) | 262 | (62) | (216) | (48) | 0 | 0 | (260) | (129) | (320) | (83) | (1,387) | 1,437 | (51) |
| Aug-02 | LL | 882 | (366) | 20 | (62) | (216) | (48) | 0 | 0 | (260) | (67) | (100) | (29) | (1,148) | 902 | 246 |
| Sep-02 | HL | 1,040 | (259) | 242 | (54) | (216) | (48) | 0 | 0 | (265) | (105) | (199) | (100) | (1,246) | 1,282 | (36) |
| Sep-02 | LL | 830 | (346) | 33 | (54) | (216) | (48) | 0 | 0 | (265) | (60) | (88) | (48) | (1,125) | 864 | 261 |
| Oct-02 | HL | 1,069 | (259) | 121 | (62) | (216) | (48) | 0 | 0 | (265) | (106) | (202) | (119) | (1,277) | 1,189 | 88 |
| Oct-02 | LL | 853 | (356) | 20 | (62) | (216) | (48) | 0 | 0 | (265) | (55) | (76) | (60) | (1,138) | 873 | 265 |
| Nov-02 | HL | 1,191 | (343) | 116 | (62) | (216) | (48) | 0 | 0 | (270) | (107) | (370) | (138) | (1,554) | 1,306 | 248 |
| Nov-02 | LL | 968 | (469) | 26 | (62) | (216) | (48) | 0 | 0 | (270) | (58) | (125) | (70) | (1,318) | 993 | 325 |

# Enron Canada Corp.
May 2, 2001

CONFIDENTIAL

| AECO / NIT ($CND/GJ) | | | Fixed Price ($CND/GJ) BID | Fixed Price ($CND/GJ) OFFER | Basis ($US /MMBtu) BID | Basis ($US /MMBtu) OFFER | Aeco/Empress Transport BID | Aeco/Empress Transport OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash | | (Physical) | 6.043 | 6.053 | | | | |
| ROM | | | 6.175 | 6.185 | | | - | 0.015 |
| Jun-01 | | (Physical) | 6.245 | 6.255 | (0.351) | (0.331) | - | 0.025 |
| Jun-01 | to | Oct-01 | 6.408 | 6.428 | (0.350) | (0.330) | (0.010) | 0.010 |
| Nov-01 | to | Mar-02 | 7.043 | 7.063 | (0.250) | (0.230) | 0.140 | 0.160 |
| Apr-02 | to | Oct-02 | 6.072 | 6.092 | (0.350) | (0.330) | 0.140 | 0.160 |
| Nov-01 | to | Oct-02 | 6.477 | 6.497 | (0.310) | (0.290) | 0.140 | 0.160 |


MAIN PHONE (403) 974-6701

MAIN FAX (403) 974-6706

| | | | |
|---|---|---|---|
| Howard Sangwine | 974-6704 | Eric Le Dain | 974-6741 |
| Mike Cowan | 974-6712 | Jon McKay | 974-6733 |
| Derek Davies | 974-6793 | Rob Milnthorp | 974-6714 |
| Dean Drozdiak | 974-6751 | Cynlia Di Stefano | 974-6750 |
| | | Grant Oh | 974-6778 |


| | | | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE |
|---|---|---|---|---|---|
| Cash | | (Physical) | 1.534 | 4.550 | |
| ROM | | | | 4.590 | |
| Jun-01 | | | | | 4.641 |
| Jun-01 | to | Oct-01 | | | 4.755 |
| Nov-01 | to | Mar-02 | | | 5.090 |
| Apr-02 | to | Oct-02 | | | 4.520 |
| Nov-01 | to | Oct-02 | | | 4.759 |

| | | | ROCKIES ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SAN JUAN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | DAWN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash | | (Physical) | 4.140 | 4.160 | | | 4.515 | 4.535 | | | 4.750 | 4.770 | | |
| ROM | | | 3.835 | 3.855 | | | 4.085 | 4.105 | | | 4.840 | 4.860 | | |
| Jun-01 | | | 3.791 | 3.811 | (0.850) | (0.830) | 4.186 | 4.206 | (0.455) | (0.435) | 4.871 | 4.891 | 0.230 | 0.250 |
| Jun-01 | to | Oct-01 | 3.820 | 3.840 | (0.935) | (0.915) | 4.315 | 4.335 | (0.440) | (0.420) | 4.980 | 5.000 | 0.225 | 0.245 |
| Nov-01 | to | Mar-02 | 4.795 | 4.815 | (0.295) | (0.275) | 4.905 | 4.925 | (0.185) | (0.165) | 5.430 | 5.450 | 0.340 | 0.360 |
| Apr-02 | to | Oct-02 | 3.860 | 3.880 | (0.660) | (0.640) | 4.280 | 4.300 | (0.240) | (0.220) | 4.735 | 4.755 | 0.215 | 0.235 |
| Nov-01 | to | Oct-02 | 4.254 | 4.274 | (0.505) | (0.485) | 4.544 | 4.564 | (0.215) | (0.195) | 5.029 | 5.049 | 0.270 | 0.290 |

| | | | STATION 2 Fixed Price ($C/GJ) BID | Fixed Price OFFER | Basis ($US/MMBtu) BID | Basis OFFER | MALIN ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | VENTURA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | NIAGARA ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash | | (Physical) | 6.330 | 6.360 | | | 7.940 | 7.960 | | | 4.465 | 4.485 | | | 4.720 | 4.740 | | |
| ROM | | | 6.665 | 6.695 | | | 8.085 | 8.105 | | | 4.510 | 4.530 | | | 4.840 | 4.860 | | |
| Jun-01 | | | 6.433 | 6.463 | (0.215) | (0.195) | 8.631 | 8.651 | 3.990 | 4.010 | 4.611 | 4.631 | (0.030) | (0.010) | 4.901 | 4.921 | 0.260 | 0.280 |
| Jun-01 | to | Oct-01 | 6.606 | 6.636 | (0.210) | (0.190) | 8.695 | 8.715 | 3.940 | 3.960 | 4.725 | 4.745 | (0.030) | (0.010) | 5.010 | 5.030 | 0.255 | 0.275 |
| Nov-01 | to | Mar-02 | 7.482 | 7.512 | 0.055 | 0.075 | 8.720 | 8.740 | 3.630 | 3.650 | 5.230 | 5.250 | 0.140 | 0.160 | 5.590 | 5.610 | 0.500 | 0.520 |
| Apr-02 | to | Oct-02 | 6.620 | 6.650 | 0.030 | 0.050 | 5.960 | 5.980 | 1.440 | 1.460 | 4.525 | 4.545 | 0.005 | 0.025 | 4.780 | 4.800 | 0.260 | 0.280 |
| Nov-01 | to | Oct-02 | 6.981 | 7.011 | 0.040 | 0.060 | 7.119 | 7.139 | 2.360 | 2.380 | 4.819 | 4.839 | 0.060 | 0.080 | 5.119 | 5.139 | 0.360 | 0.380 |

1yr

| | | | SUMAS ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | SoCAL ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | CHICAGO CITY GATE ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER | TRANSCO Z6 ($US/MMBtu) Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash | | (Physical) | 4.535 | 4.555 | | | 13.190 | 13.210 | | | 4.660 | 4.680 | | | 5.005 | 5.025 | | |
| ROM | | | 4.690 | 4.710 | | | 13.835 | 13.855 | | | 4.680 | 4.700 | | | 5.000 | 5.020 | | |
| Jun-01 | | | 4.871 | 4.891 | 0.230 | 0.250 | 12.731 | 12.751 | 8.090 | 8.110 | 4.741 | 4.761 | 0.100 | 0.120 | 5.061 | 5.081 | 0.420 | 0.440 |
| Jun-01 | to | Oct-01 | 4.985 | 5.005 | 0.230 | 0.250 | 12.415 | 12.435 | 7.660 | 7.680 | 4.855 | 4.875 | 0.100 | 0.120 | 5.230 | 5.250 | 0.475 | 0.495 |
| Nov-01 | to | Mar-02 | 8.465 | 8.485 | 3.375 | 3.395 | 10.765 | 10.785 | 5.675 | 5.695 | 5.295 | 5.315 | 0.205 | 0.225 | 6.640 | 6.660 | 1.550 | 1.570 |
| Apr-02 | to | Oct-02 | 4.660 | 4.680 | 0.140 | 0.160 | 6.415 | 6.435 | 1.895 | 1.915 | 4.615 | 4.635 | 0.095 | 0.115 | 4.985 | 5.005 | 0.465 | 0.485 |
| Nov-01 | to | Oct-02 | 6.254 | 6.274 | 1.495 | 1.515 | 8.239 | 8.259 | 3.480 | 3.500 | 4.899 | 4.919 | 0.140 | 0.160 | 5.679 | 5.699 | 0.920 | 0.940 |

[redacted]

## Avista Utilities
## Gas/Electric Transaction

Date of Transaction: 5-10-01 Reference No. ____________

Transaction Details: Purchase / Sale (Circle) Financial

Delivery Period June 1, 2002 thru October 31, 2003

Volume 10,000 MMBtu/day

Location ____________

Price Fixed Price $5.35 (Lock in Malin NGI monthly index)

~~Broker~~ Avista Energy

Market Conditions: Forward Electric Prices Calendar 2002 + 2003 heavy load are $147.25 + $64.75 respectively.

System Position and Reason for Action (Attach Position Report): The gas to run Coyote has been purchased @ an index price - locking in the gas price fixes the cost of generation significantly below the forward market price of power.

Dispatchability: ____________

Transmission Alternatives: ____________

Building Options: ____________

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DRAFT
JRT 10/2/00

Financial and Rate Impacts: Gas price locked in to fix cost to generate @ Coyote Springs 2 - significantly below forward power prices.

Market Quotes: Broker ____________ Quote ______________

Broker ____________ Quote ______________

Broker ____________ Quote ______________

Completed by: ______________________ Date: ____________________

\$5.35 fixed price + \$.06 original purchase over index = \$5.41

\$5.41 x 6.9 HR = \$37.33 /MW Cost to generate

Market Price of Power HL 2002 \$147.25

HL 2003 \$64.75

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Corporation

Gas Supply

Price Quotation Summary Sheet

PAPER SWAP

CS 2 Suppl

2009

Date: 5-10-01 Company: AVISTA ENERGY

Representative:

(Name) BILL JAMISON

(Title)

(Phone #)

(FAX #)

Volume: 10000 MMBtu Price Quoted: $ 5.35 /MMBtu

Period: From: June 02 To: OCT 31, 03

Type: ☐ Firm ☐ Interruptible

Maximum Take: PAPER MMBtu per ☒ Day ☐ Month

Minimum Take: ______ MMBtu per ☐ Day ☐ Month

Reservation Fee: $ ______ /MMBtu

Receipt Point: MALIN FIXED FOR FLOAT

Pipeline: ☐ Northwest ☒ PGT

WE PAY FIXED @ 5.35
AE PAYS INDEX @ MALIN

☐ Accepted ☐ Rejected Date:

IF ACCEPTED: Date of Contract:

Company Address:

Accounting Contact: (Name)
(Phone #)
(FAX #)

Wire Transfer Contact: (Name)
(Phone #)
(FAX #)
Bank:
Account #:
Date of Payment:

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*Avista Utilities*
Position Report
2001-05-09.xls

Indicates positions outside of risk policy limits

| Month | Hrs | Index Purchase (Sale) [a] | Physical Position Long (Short) [b] | Financial Put (Call) Net Delta [c] | Total Position Long (Short) [d] | CT Inc in Phy Fuel Pur | CT Turb. Fuel Not Pur [e] | Physical Open Position [f] | Financial Open Position [g] | Financial Quarter Average | Fin & NG Open Position [h] | Month Short Limit | Month Long Limit | Fin & NG Quarter Average | Quarter Short Limit | Quarter Long Limit | Month | Hrs | Hrs | Impact of $50 Price Increase |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Col (1) | Col (2) | Col (3) | Col (4) Col (2) + Col (3) | Col (5) | Col (6) | Col (7) Col (4) + Col (6) | Col (8) Col (7) - Col (1) | Col (9) Avg Col 8 | Col (10) Col (8) - Col (6) | Col (11) | Col (12) | Col (13) Avg Col 10 | Col (14) | Col (15) | | | | |
| Jun-01 | HL | (5) | (30) | 0 | (30) | 124 | 0 | (30) | (25) | | (25) | (25) | 125 | | | | Jun-01 | HL | 416 | $ (526,450) |
| Jun-01 | LL | (5) | 52 | 0 | 52 | 120 | 0 | 52 | 57 | | 57 | (25) | 125 | | | | Jun-01 | LL | 304 | $ 869,000 |
| Jul-01 | HL | (5) | (30) | 0 | (30) | 150 | 0 | (30) | (25) | | (25) | (75) | 200 | | | | Jul-01 | HL | 400 | $ (509,150) |
| Jul-01 | LL | (5) | 16 | 0 | 16 | 150 | 0 | 16 | 21 | | 21 | (75) | 200 | | | | Jul-01 | LL | 344 | $ 364,950 |
| Aug-01 | HL | 5 | (21) | 0 | (21) | 200 | 0 | (21) | (26) | 7 | (26) | (75) | 200 | 7 | (25) | 150 | Aug-01 | HL | 432 | $ (562,450) |
| Aug-01 | LL | 5 | 46 | 0 | 46 | 200 | 0 | 46 | 41 | 57 | 41 | (75) | 200 | 57 | (25) | 150 | Aug-01 | LL | 312 | $ 642,000 |
| Sep-01 | HL | (5) | 67 | 0 | 67 | 208 | 0 | 67 | 72 | | 72 | (75) | 200 | | | | Sep-01 | HL | 384 | $ 1,388,200 |
| Sep-01 | LL | (5) | 103 | 0 | 103 | 208 | 0 | 103 | 108 | | 108 | (75) | 200 | | | | Sep-01 | LL | 336 | $ 1,810,800 |
| Oct-01 | HL | (5) | (42) | 0 | (42) | 208 | 0 | (42) | (37) | | (37) | (150) | 250 | | | | Oct-01 | HL | 432 | $ (795,750) |
| Oct-01 | LL | (5) | 101 | 0 | 101 | 208 | 0 | 101 | 106 | | 106 | (150) | 250 | | | | Oct-01 | LL | 312 | $ 1,650,400 |
| Nov-01 | HL | (5) | 71 | 0 | 71 | 219 | 0 | 71 | 76 | 48 | 76 | (150) | 250 | 48 | (50) | 150 | Nov-01 | HL | 400 | $ 1,516,600 |
| Nov-01 | LL | (5) | 86 | (87) | (1) | 160 | 0 | (1) | 4 | 28 | 4 | (150) | 250 | 28 | (50) | 150 | Nov-01 | LL | 320 | $ 64,300 |
| Dec-01 | HL | (5) | 100 | 0 | 100 | 219 | 0 | 100 | 105 | | 105 | (150) | 250 | | | | Dec-01 | HL | 400 | $ 2,098,000 |
| Dec-01 | LL | (5) | 41 | (73) | (32) | 160 | 0 | (32) | (27) | | (27) | (150) | 250 | | | | Dec-01 | LL | 344 | $ (464,950) |
| Jan-02 | HL | (5) | 82 | 0 | 82 | 99 | 61 | 143 | 148 | | 87 | (150) | 250 | | | | Jan-02 | HL | 416 | $ 3,085,500 |
| Jan-02 | LL | (5) | 114 | (69) | 45 | 99 | 61 | 106 | 111 | | 50 | (150) | 250 | | | | Jan-02 | LL | 328 | $ 1,818,200 |
| Feb-02 | HL | (5) | 73 | 0 | 73 | 99 | 41 | 114 | 119 | 132 | 78 | (150) | 250 | 91 | (50) | 150 | Feb-02 | HL | 384 | $ 2,286,300 |
| Feb-02 | LL | (5) | 164 | (81) | 84 | 99 | 41 | 125 | 130 | 122 | 89 | (150) | 250 | 81 | (50) | 150 | Feb-02 | LL | 288 | $ 1,864,850 |
| Mar-02 | HL | (5) | 103 | 0 | 103 | 99 | 19 | 122 | 127 | | 108 | (150) | 250 | | | | Mar-02 | HL | 416 | $ 2,645,200 |
| Mar-02 | LL | (5) | 185 | (84) | 101 | 99 | 20 | 121 | 126 | | 106 | (150) | 250 | | | | Mar-02 | LL | 328 | $ 2,059,700 |
| Apr-02 | HL | (5) | 172 | (74) | 98 | 99 | 56 | 154 | 159 | | 103 | (150) | 250 | | | | Apr-02 | HL | 416 | $ 3,307,950 |
| Apr-02 | LL | (5) | 173 | (58) | 115 | 99 | 56 | 171 | 176 | | 120 | (150) | 250 | | | | Apr-02 | LL | 304 | $ 2,677,600 |
| May-02 | HL | (5) | 197 | 0 | 197 | 99 | 47 | 244 | 249 | 210 | 202 | (150) | 250 | 175 | (50) | 150 | May-02 | HL | 416 | $ 5,188,000 |
| May-02 | LL | (5) | 174 | 0 | 174 | 99 | 44 | 218 | 223 | 207 | 179 | (150) | 250 | 174 | (50) | 150 | May-02 | LL | 328 | $ 3,659,550 |
| Jun-02 | HL | (5) | 290 | (75) | 215 | 119 | 0 | 215 | 220 | | 220 | (150) | 250 | | | | Jun-02 | HL | 400 | $ 4,401,200 |
| Jun-02 | LL | (5) | 294 | (77) | 216 | 119 | 0 | 216 | 221 | | 221 | (150) | 250 | | | | Jun-02 | LL | 320 | $ 3,539,650 |
| Jul-02 | HL | (5) | 244 | 0 | 244 | 150 | 0 | 244 | 249 | | 249 | (175) | 250 | | | | Jul-02 | HL | 416 | $ 5,175,700 |
| Jul-02 | LL | (5) | 215 | 0 | 215 | 150 | 0 | 215 | 220 | | 220 | (175) | 250 | | | | Jul-02 | LL | 328 | $ 3,608,200 |
| Aug-02 | HL | 5 | (51) | 0 | (51) | 260 | 200 | 149 | 144 | 192 | (56) | (175) | 250 | 56 | (75) | 150 | Aug-02 | HL | 432 | $ 3,121,050 |
| Aug-02 | LL | 5 | 245 | 0 | 245 | 260 | 200 | 445 | 441 | 378 | 241 | (175) | 250 | 242 | (75) | 150 | Aug-02 | LL | 312 | $ 6,872,350 |
| | | | | | | | | | | | | | | | | | Jan-00 | 0 | | |
| Sep-02 | HL | (5) | (32) | 0 | (32) | 265 | 208 | 176 | 181 | | (27) | (175) | 250 | | | | Sep-02 | HL | 384 | $ 3,483,550 |
| Sep-02 | LL | (5) | 261 | 0 | 261 | 265 | 208 | 469 | 474 | | 266 | (175) | 250 | | | | Sep-02 | LL | 336 | $ 7,963,050 |
| Oct-02 | HL | (5) | 88 | 0 | 88 | 265 | 208 | 296 | 301 | | 93 | (175) | 250 | | | | Oct-02 | HL | 432 | $ 6,500,150 |
| Oct-02 | LL | (5) | 265 | 0 | 265 | 265 | 208 | 473 | 478 | | 270 | (175) | 250 | | | | Oct-02 | LL | 312 | $ 7,452,700 |
| Nov-02 | HL | (5) | 249 | 0 | 249 | 270 | 218 | 467 | 472 | | 254 | (175) | 250 | | | | Nov-02 | HL | 400 | $ 9,438,350 |
| Nov-02 | LL | (5) | 325 | (43) | 282 | 270 | 160 | 442 | 447 | | 287 | (175) | 250 | | | | Nov-02 | LL | 320 | $ 7,151,050 |

Footnotes: [a] Index transactions are already included in the total physical position. [b] Physical position. [c] Aggregate physical equivalent (delta) position of options (put and calls). [d] Total position is the combined physical and delta positions. [e] Turbines in this column are available for use, but gas has not been purchased. When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column. [f] Open physical position includes total position and available turbines. [g] Open financial position includes open physical position less any index position. [h] Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased. At its meeting on May 3, 2001, the Risk Management Committee suspended the cure date for the positions in Q2 02, Q3 02, Sep 02, Oct 02, and Nov 02 which are longer than the long limits. These positions will be re-evaluated on a monthly basis by the Risk Management Committee.

# *Avista Utilities*

## Physical Surplus-(Deficiency)

2001-05-09.xls

Indicates Changes

| Month | Hours | Native Load | Contract Purchases | Contract Sales | PURPA Contracts | Colstrip | Kettle Falls | NECT | Rathdrum | Coyote Springs | Mid -C Hydro | Clark Fork Hydro | Spokane Hydro | Total Resource | Total Obligation | Physical Surplus/ (Deficiency) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) |
| Jun-01 | HL | 1,016 | (703) | 910 | (31) | (216) | (48) | | (124) | | (118) | (500) | (155) | (1,896) | 1,926 | (30) |
| Jun-01 | LL | 798 | (727) | 595 | (31) | (216) | (48) | | (120) | | (62) | (164) | (77) | (1,445) | 1,393 | 52 |
| Jul-01 | HL | 1,122 | (1,154) | 947 | (62) | (216) | (48) | | (150) | | (128) | (219) | (61) | (2,039) | 2,069 | (30) |
| Jul-01 | LL | 867 | (768) | 594 | (62) | (216) | (48) | | (150) | | (72) | (108) | (53) | (1,477) | 1,461 | 16 |
| Aug-01 | HL | 1,155 | (890) | 621 | (62) | (216) | (48) | (50) | (150) | | (110) | (182) | (47) | (1,754) | 1,776 | (21) |
| Aug-01 | LL | 862 | (587) | 362 | (62) | (216) | (48) | (50) | (150) | | (58) | (77) | (21) | (1,270) | 1,224 | 46 |
| Sep-01 | HL | 1,016 | (880) | 636 | (54) | (216) | (48) | (52) | (156) | | (88) | (160) | (66) | (1,720) | 1,652 | 67 |
| Sep-01 | LL | 809 | (567) | 345 | (54) | (216) | (48) | (52) | (156) | | (50) | (75) | (38) | (1,257) | 1,154 | 103 |
| Oct-01 | HL | 1,045 | (509) | 407 | (62) | (216) | (48) | (52) | (156) | | (91) | (200) | (77) | (1,410) | 1,452 | (42) |
| Oct-01 | LL | 829 | (456) | 234 | (62) | (216) | (48) | (52) | (156) | | (47) | (75) | (51) | (1,164) | 1,063 | 101 |
| Nov-01 | HL | 1,167 | (593) | 406 | (62) | (216) | (48) | (59) | (160) | | (106) | (282) | (118) | (1,644) | 1,573 | 71 |
| Nov-01 | LL | 954 | (569) | 241 | (62) | (216) | (48) | 0 | (160) | | (59) | (103) | (65) | (1,281) | 1,195 | 86 |
| Dec-01 | HL | 1,256 | (607) | 390 | (62) | (216) | (48) | (59) | (160) | | (128) | (310) | (157) | (1,746) | 1,646 | 100 |
| Dec-01 | LL | 1,038 | (565) | 239 | (62) | (216) | (48) | 0 | (160) | | (72) | (117) | (78) | (1,318) | 1,277 | 41 |
| Jan-02 | HL | 1,265 | (416) | 151 | (62) | (216) | (48) | | (99) | | (179) | (310) | (169) | (1,499) | 1,416 | 82 |
| Jan-02 | LL | 1,043 | (474) | 26 | (62) | (216) | (48) | | (99) | | (98) | (108) | (77) | (1,182) | 1,068 | 114 |
| Feb-02 | HL | 1,204 | (414) | 147 | (62) | (216) | (48) | | (99) | | (152) | (255) | (178) | (1,424) | 1,351 | 73 |
| Feb-02 | LL | 1,000 | (477) | 20 | (62) | (216) | (48) | | (99) | | (81) | (90) | (111) | (1,184) | 1,020 | 164 |
| Mar-02 | HL | 1,112 | (350) | 144 | (62) | (216) | (48) | | (99) | | (126) | (280) | (178) | (1,360) | 1,256 | 103 |
| Mar-02 | LL | 923 | (411) | 20 | (62) | (216) | (48) | | (99) | | (69) | (101) | (123) | (1,128) | 943 | 185 |
| Apr-02 | HL | 1,043 | (101) | 123 | (62) | (216) | (48) | | (99) | | (103) | (492) | (217) | (1,339) | 1,166 | 172 |
| Apr-02 | LL | 838 | (216) | 20 | (62) | (216) | (48) | | (99) | | (54) | (175) | (162) | (1,031) | 858 | 173 |
| May-02 | HL | 1,060 | (59) | 123 | (62) | (108) | (28) | | (99) | | (114) | (740) | (170) | (1,380) | 1,183 | 197 |
| May-02 | LL | 854 | (151) | 26 | (62) | (108) | (25) | | (99) | | (62) | (405) | (142) | (1,054) | 880 | 174 |
| Jun-02 | HL | 1,038 | (59) | 147 | (31) | (151) | (48) | | (119) | | (139) | (750) | (178) | (1,475) | 1,185 | 290 |
| Jun-02 | LL | 827 | (151) | 20 | (31) | (151) | (48) | | (119) | | (77) | (459) | (105) | (1,141) | 847 | 294 |
| Jul-02 | HL | 1,158 | (259) | 156 | (62) | (216) | (48) | | (150) | | (124) | (570) | (128) | (1,557) | 1,313 | 244 |
| Jul-02 | LL | 894 | (351) | 27 | (62) | (216) | (48) | | (150) | | (67) | (175) | (67) | (1,136) | 921 | 215 |
| Aug-02 | HL | 1,175 | (269) | 262 | (62) | (216) | (48) | | | (260) | (129) | (320) | (83) | (1,386) | 1,437 | (51) |
| Aug-02 | LL | 882 | (366) | 20 | (62) | (216) | (48) | | | (260) | (67) | (100) | (29) | (1,148) | 902 | 245 |
| Sep-02 | HL | 1,040 | (259) | 238 | (54) | (216) | (48) | | | (265) | (105) | (199) | (100) | (1,246) | 1,277 | (32) |
| Sep-02 | LL | 830 | (346) | 33 | (54) | (216) | (48) | | | (265) | (60) | (88) | (48) | (1,125) | 864 | 261 |
| Oct-02 | HL | 1,069 | (259) | 121 | (62) | (216) | (48) | | | (265) | (106) | (202) | (119) | (1,277) | 1,189 | 88 |
| Oct-02 | LL | 853 | (356) | 20 | (62) | (216) | (48) | | | (265) | (55) | (76) | (60) | (1,138) | 873 | 265 |
| Nov-02 | HL | 1,191 | (343) | 115 | (62) | (216) | (48) | | | (270) | (107) | (370) | (138) | (1,554) | 1,306 | 249 |
| Nov-02 | LL | 968 | (469) | 26 | (62) | (216) | (48) | | | (270) | (58) | (125) | (70) | (1,318) | 993 | 325 |

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# Enron Canada Corp.

May 10, 2001

| AECO / NIT ($CND/GJ) | | Fixed Price ($CND/GJ) BID | OFFER | Basis ($US /MMBtu) BID | OFFER | Aeco/Empress Transport BID | OFFER |
|---|---|---|---|---|---|---|---|
| Cash | (Physical) | 5.625 | 5.635 | | | | |
| ROM | | 5.655 | 5.665 | | | - | (0.010) |
| Jun-01 | (Physical) | 5.715 | 5.725 | (0.291) | (0.271) | - | (0.010) |
| Jun-01 to Oct-01 | | 5.861 | 5.881 | (0.305) | (0.285) | (0.010) | 0.010 |
| Nov-01 to Mar-02 | | 6.413 | 6.433 | (0.280) | (0.260) | 0.140 | 0.160 |
| Apr-02 to Oct-02 | | 5.628 | 5.648 | (0.365) | (0.345) | 0.140 | 0.160 |
| Nov-01 to Oct-02 | | 5.956 | 5.976 | (0.330) | (0.310) | 0.140 | 0.160 |


**MAIN PHONE**
**(403) 974-6701**

**MAIN FAX**
**(403) 974-6706**

| | | | |
|---|---|---|---|
| Howard Sangwine | 974-6704 | Eric Le Dain | 974-6741 |
| Mike Cowan | 974-6712 | Jon McKay | 974-6733 |
| Derek Davies | 974-6793 | Rob Milnthorp | 974-6714 |
| Dean Drozdiak | 974-6751 | Cynlia Di Stefano | 974-6750 |
| | | Grant Oh | 974-6778 |


| | | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE |
|---|---|---|---|---|
| Cash | (Physical) | 1.538 | 4.145 | |
| ROM | | | 4.160 | |
| Jun-01 | | | | 4.202 |
| Jun-01 to Oct-01 | | | | 4.317 |
| Nov-01 to Mar-02 | | | | 4.668 |
| Apr-02 to Oct-02 | | | | 4.212 |
| Nov-01 to Oct-02 | | | | 4.403 |

| | ROCKIES ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | SAN JUAN ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | DAWN ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 3.560 | 3.580 | | | | | | | 4.395 | 4.415 | | |
| ROM | 3.490 | 3.510 | | | 3.490 | 3.510 | | | 4.410 | 4.430 | | |
| Jun-01 | 3.357 | 3.377 | (0.845) | (0.825) | 3.712 | 3.732 | (0.490) | (0.470) | 4.412 | 4.432 | 0.210 | 0.230 |
| Jun-01 to Oct-01 | 3.342 | 3.362 | (0.975) | (0.955) | 3.817 | 3.837 | (0.500) | (0.480) | 4.502 | 4.522 | 0.185 | 0.205 |
| Nov-01 to Mar-02 | 4.268 | 4.288 | (0.400) | (0.380) | 4.378 | 4.398 | (0.290) | (0.270) | 4.958 | 4.978 | 0.290 | 0.310 |
| Apr-02 to Oct-02 | 3.417 | 3.437 | (0.795) | (0.775) | 3.882 | 3.902 | (0.330) | (0.310) | 4.392 | 4.412 | 0.180 | 0.200 |
| Nov-01 to Oct-02 | 3.773 | 3.793 | (0.630) | (0.610) | 4.088 | 4.108 | (0.315) | (0.295) | 4.628 | 4.648 | 0.225 | 0.245 |

| | STATION 2 Fixed Price ($C/GJ) BID | OFFER | Basis ($US/MMBtu) BID | OFFER | MALIN ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 5.730 | 5.760 | | | 4.595 | 4.615 | | |
| ROM | 5.985 | 6.015 | | | 4.840 | 4.860 | | |
| Jun-01 | 5.904 | 5.934 | (0.155) | (0.135) | 6.692 | 6.712 | 2.490 | 2.510 |
| Jun-01 to Oct-01 | 6.053 | 6.083 | (0.170) | (0.150) | 6.972 | 6.992 | 2.655 | 2.675 |
| Nov-01 to Mar-02 | 6.949 | 6.979 | 0.090 | 0.110 | 7.408 | 7.428 | 2.740 | 2.760 |
| Apr-02 to Oct-02 | 6.171 | 6.201 | 0.010 | 0.030 | 5.452 | 5.472 | 1.240 | 1.260 |
| Nov-01 to Oct-02 | 6.499 | 6.529 | 0.045 | 0.065 | 6.273 | 6.293 | 1.870 | 1.890 |

only 1 year

| | VENTURA ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | NIAGARA ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 4.045 | 4.065 | | | 4.385 | 4.405 | | |
| ROM | 4.100 | 4.120 | | | 4.410 | 4.430 | | |
| Jun-01 | 4.152 | 4.172 | (0.050) | (0.030) | 4.442 | 4.462 | 0.240 | 0.260 |
| Jun-01 to Oct-01 | 4.267 | 4.287 | (0.050) | (0.030) | 4.532 | 4.552 | 0.215 | 0.235 |
| Nov-01 to Mar-02 | 4.758 | 4.778 | 0.090 | 0.110 | 5.118 | 5.138 | 0.450 | 0.470 |
| Apr-02 to Oct-02 | 4.182 | 4.202 | (0.030) | (0.010) | 4.437 | 4.457 | 0.225 | 0.245 |
| Nov-01 to Oct-02 | 4.423 | 4.443 | 0.020 | 0.040 | 4.723 | 4.743 | 0.320 | 0.340 |

| | SUMAS ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | SoCAL ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 4.050 | 4.070 | | | 12.420 | 12.440 | | |
| ROM | 4.130 | 4.150 | | | 12.640 | 12.660 | | |
| Jun-01 | 4.352 | 4.372 | 0.150 | 0.170 | 12.192 | 12.212 | 7.990 | 8.010 |
| Jun-01 to Oct-01 | 4.437 | 4.457 | 0.120 | 0.140 | 11.497 | 11.517 | 7.180 | 7.200 |
| Nov-01 to Mar-02 | 7.193 | 7.213 | 2.525 | 2.545 | 9.513 | 9.533 | 4.845 | 4.865 |
| Apr-02 to Oct-02 | 4.302 | 4.322 | 0.090 | 0.110 | 5.907 | 5.927 | 1.695 | 1.715 |
| Nov-01 to Oct-02 | 5.513 | 5.533 | 1.110 | 1.130 | 7.418 | 7.438 | 3.015 | 3.035 |

| | CHICAGO CITY GATE ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER | TRANSCO Z6 ($US/MMBtu) Fixed Price BID | OFFER | Basis BID | OFFER |
|---|---|---|---|---|---|---|---|---|
| Cash (Physical) | 4.220 | 4.240 | | | 4.505 | 4.525 | | |
| ROM | 4.250 | 4.270 | | | 4.530 | 4.550 | | |
| Jun-01 | 4.292 | 4.312 | 0.090 | 0.110 | 4.607 | 4.627 | 0.405 | 0.425 |
| Jun-01 to Oct-01 | 4.407 | 4.427 | 0.090 | 0.110 | 4.787 | 4.807 | 0.470 | 0.490 |
| Nov-01 to Mar-02 | 4.838 | 4.858 | 0.170 | 0.190 | 6.203 | 6.223 | 1.535 | 1.555 |
| Apr-02 to Oct-02 | 4.292 | 4.312 | 0.080 | 0.100 | 4.677 | 4.697 | 0.465 | 0.485 |
| Nov-01 to Oct-02 | 4.523 | 4.543 | 0.120 | 0.140 | 5.318 | 5.338 | 0.915 | 0.935 |

**CONFIDENTIAL**

# Enron Canada Corp.
## May 11, 2001


**MAIN PHONE (403) 974-6701**

**MAIN FAX (403) 974-6706**

| | | | |
|---|---|---|---|
| Howard Sangwine | 974-6704 | Eric Le Dain | 974-6741 |
| Mike Cowan | 974-6712 | Jon McKay | 974-6733 |
| Derek Davies | 974-6793 | Rob Milnthorp | 974-6714 |
| Dean Drozdiak | 974-6751 | Cyntia Di Stefano | 974-6750 |
| | | Grant Oh | 974-6778 |


### AECO / NIT ($CND/GJ)

| | Fixed Price ($CND/GJ) BID | Fixed Price OFFER | Basis ($US /MMBtu) BID | Basis OFFER | Aeco/Empress Transport BID | Aeco/Empress Transport OFFER |
|---|---|---|---|---|---|---|
| Cash (Physical) | 5.698 | 5.708 | | | | |
| ROM | 5.815 | 5.825 | | | - | (0.010) |
| Jun-01 (Physical) | 5.935 | 5.945 | (0.296) | (0.276) | - | (0.010) |
| Jun-01 to Oct-01 | 6.070 | 6.090 | (0.305) | (0.285) | (0.010) | 0.010 |
| Nov-01 to Mar-02 | 6.547 | 6.567 | (0.270) | (0.250) | 0.140 | 0.160 |
| Apr-02 to Oct-02 | 5.669 | 5.689 | (0.360) | (0.340) | 0.140 | 0.160 |
| Nov-01 to Oct-02 | 6.040 | 6.060 | (0.320) | (0.300) | 0.140 | 0.160 |

| | F/X CAD/USD | Henry Hub ($US/MMBtu) SETTLE | NYMEX ($US/MMBtu) SETTLE |
|---|---|---|---|
| Cash (Physical) | 1.544 | 4.165 | |
| ROM | | 4.260 | |
| Jun-01 | | | 4.348 |
| Jun-01 to Oct-01 | | | 4.452 |
| Nov-01 to Mar-02 | | | 4.740 |
| Apr-02 to Oct-02 | | | 4.228 |
| Nov-01 to Oct-02 | | | 4.442 |

### ROCKIES ($US/MMBtu)

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 3.360 | 3.380 | | |
| ROM | 3.390 | 3.410 | | |
| Jun-01 | 3.468 | 3.488 | (0.880) | (0.860) |
| Jun-01 to Oct-01 | 3.427 | 3.447 | (1.025) | (1.005) |
| Nov-01 to Mar-02 | 4.330 | 4.350 | (0.410) | (0.390) |
| Apr-02 to Oct-02 | 3.378 | 3.398 | (0.850) | (0.830) |
| Nov-01 to Oct-02 | 3.777 | 3.797 | (0.665) | (0.645) |

### SAN JUAN ($US/MMBtu)

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | #N/A | #N/A | | |
| ROM | 3.530 | 3.550 | | |
| Jun-01 | 3.838 | 3.858 | (0.510) | (0.490) |
| Jun-01 to Oct-01 | 3.932 | 3.952 | (0.520) | (0.500) |
| Nov-01 to Mar-02 | 4.440 | 4.460 | (0.300) | (0.280) |
| Apr-02 to Oct-02 | 3.868 | 3.888 | (0.360) | (0.340) |
| Nov-01 to Oct-02 | 4.107 | 4.127 | (0.335) | (0.315) |

### DAWN ($US/MMBtu)

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 4.415 | 4.435 | | |
| ROM | 4.550 | 4.570 | | |
| Jun-01 | 4.563 | 4.583 | 0.215 | 0.235 |
| Jun-01 to Oct-01 | 4.642 | 4.662 | 0.190 | 0.210 |
| Nov-01 to Mar-02 | 5.030 | 5.050 | 0.290 | 0.310 |
| Apr-02 to Oct-02 | 4.423 | 4.443 | 0.195 | 0.215 |
| Nov-01 to Oct-02 | 4.672 | 4.692 | 0.230 | 0.250 |

### STATION 2

| | Fixed Price ($C/GJ) BID | Fixed Price OFFER | Basis ($US/MMBtu) BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 5.580 | 5.610 | | |
| ROM | 5.955 | 5.985 | | |
| Jun-01 | 6.123 | 6.153 | (0.160) | (0.140) |
| Jun-01 to Oct-01 | 6.270 | 6.300 | (0.165) | (0.145) |
| Nov-01 to Mar-02 | 7.069 | 7.099 | 0.090 | 0.110 |
| Apr-02 to Oct-02 | 6.213 | 6.243 | 0.015 | 0.035 |
| Nov-01 to Oct-02 | 6.570 | 6.600 | 0.045 | 0.065 |

### MALIN ($US/MMBtu)

5/11/01

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 5.885 | 5.905 | | |
| ROM | 4.690 | 4.710 | | |
| Jun-01 | 6.588 | 6.608 | 2.240 | 2.260 |
| Jun-01 to Oct-01 | 6.977 | 6.997 | 2.525 | 2.545 |
| Nov-01 to Mar-02 | 7.685 | 7.705 | 2.945 | 2.965 |
| Apr-02 to Oct-02 | 5.418 | 5.438 | 1.190 | 1.210 |
| Nov-01 to Oct-02 | 6.367 | 6.387 | 1.925 | 1.945 |

### VENTURA ($US/MMBtu)

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 4.055 | 4.075 | | |
| ROM | 4.200 | 4.220 | | |
| Jun-01 | 4.298 | 4.318 | (0.050) | (0.030) |
| Jun-01 to Oct-01 | 4.402 | 4.422 | (0.050) | (0.030) |
| Nov-01 to Mar-02 | 4.830 | 4.850 | 0.090 | 0.110 |
| Apr-02 to Oct-02 | 4.198 | 4.218 | (0.030) | (0.010) |
| Nov-01 to Oct-02 | 4.462 | 4.482 | 0.020 | 0.040 |

### NIAGARA ($US/MMBtu)

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 4.385 | 4.405 | | |
| ROM | 4.550 | 4.570 | | |
| Jun-01 | 4.593 | 4.613 | 0.245 | 0.265 |
| Jun-01 to Oct-01 | 4.672 | 4.692 | 0.220 | 0.240 |
| Nov-01 to Mar-02 | 5.190 | 5.210 | 0.450 | 0.470 |
| Apr-02 to Oct-02 | 4.468 | 4.488 | 0.240 | 0.260 |
| Nov-01 to Oct-02 | 4.767 | 4.787 | 0.325 | 0.345 |

### SUMAS ($US/MMBtu)

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 3.960 | 3.980 | | |
| ROM | 4.200 | 4.220 | | |
| Jun-01 | 4.478 | 4.498 | 0.130 | 0.150 |
| Jun-01 to Oct-01 | 4.572 | 4.592 | 0.120 | 0.140 |
| Nov-01 to Mar-02 | 7.465 | 7.485 | 2.725 | 2.745 |
| Apr-02 to Oct-02 | 4.318 | 4.338 | 0.090 | 0.110 |
| Nov-01 to Oct-02 | 5.637 | 5.657 | 1.195 | 1.215 |

### SoCAL ($US/MMBtu)

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 12.325 | 12.345 | | |
| ROM | 12.240 | 12.260 | | |
| Jun-01 | 12.088 | 12.108 | 7.740 | 7.760 |
| Jun-01 to Oct-01 | 11.502 | 11.522 | 7.050 | 7.070 |
| Nov-01 to Mar-02 | 9.535 | 9.555 | 4.795 | 4.815 |
| Apr-02 to Oct-02 | 5.873 | 5.893 | 1.645 | 1.665 |
| Nov-01 to Oct-02 | 7.407 | 7.427 | 2.965 | 2.985 |

### CHICAGO CITY GATE ($US/MMBtu)

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 4.235 | 4.255 | | |
| ROM | 4.350 | 4.370 | | |
| Jun-01 | 4.438 | 4.458 | 0.090 | 0.110 |
| Jun-01 to Oct-01 | 4.542 | 4.562 | 0.090 | 0.110 |
| Nov-01 to Mar-02 | 4.910 | 4.930 | 0.170 | 0.190 |
| Apr-02 to Oct-02 | 4.313 | 4.333 | 0.085 | 0.105 |
| Nov-01 to Oct-02 | 4.562 | 4.582 | 0.120 | 0.140 |

### TRANSCO Z6 ($US/MMBtu)

| | Fixed Price BID | Fixed Price OFFER | Basis BID | Basis OFFER |
|---|---|---|---|---|
| Cash (Physical) | 4.635 | 4.655 | | |
| ROM | 4.650 | 4.670 | | |
| Jun-01 | 4.753 | 4.773 | 0.405 | 0.425 |
| Jun-01 to Oct-01 | 4.922 | 4.942 | 0.470 | 0.490 |
| Nov-01 to Mar-02 | 6.275 | 6.295 | 1.535 | 1.555 |
| Apr-02 to Oct-02 | 4.693 | 4.713 | 0.465 | 0.485 |
| Nov-01 to Oct-02 | 5.357 | 5.377 | 0.915 | 0.935 |

[redacted]

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-15)

## oliday reminder

*Gas Daily* will not publish April 13 in obser- nce of Good Friday. The next issue will ap- pear April 16. The Daily Price Survey published in the April 16 issue will cover transactions conducted April 12 for gas flow April 13-16.

NYMEX will be closed April 13. NYMEX Access will be closed April 12 and is scheduled to reopen the evening of April 15.

## Gas Daily reader survey

Gas Daily's new 2001 subscriber survey — your chance to win a $200 Golfdiscount.com gift certificate. Visit www.ftenergyusa.com/gasdaily/gdsurvey.asp.

## FUTURES
## NYMEX @ Henry Hub

Results from Tuesday

| | Settlement | High | Low | Change | Volume |
|---|---|---|---|---|---|
| May., 2001 | 5.559 | 5.620 | 5.520 | 8.2 | 22,204 |
| June | 5.611 | 5.660 | 5.540 | 7.5 | 7,965 |
| July | 5.657 | 5.700 | 5.630 | 7.2 | 1,311 |
| August | 5.692 | 5.740 | 5.675 | 7.2 | 2,473 |
| September | 5.672 | 5.710 | 5.660 | 7.2 | 873 |
| October | 5.682 | 5.720 | 5.675 | 7.2 | 2,029 |
| November | 5.807 | 5.850 | 5.780 | 7.2 | 517 |
| December | 5.920 | 5.970 | 5.890 | 7.2 | 1,358 |
| Jan., 2002 | 5.957 | 6.005 | 5.945 | 7.2 | 938 |
| February | 5.767 | 5.820 | 5.760 | 6.7 | 1,272 |
| March | 5.422 | 5.480 | 5.410 | 6.7 | 667 |
| April | 4.832 | 4.860 | 4.830 | 4.2 | 770 |
| May | 4.687 | 4.750 | 4.680 | 3.2 | 309 |
| June | 4.698 | 4.750 | 4.660 | 3.8 | 335 |
| ly | 4.728 | — | — | 3.8 | 40 |
| gust | 4.735 | 4.750 | 4.720 | 3.8 | 479 |
| ptember | 4.712 | 4.750 | 4.720 | 3.5 | 622 |
| October | 4.712 | 4.700 | 4.670 | 3.5 | 96 |
| November | 4.827 | 4.890 | 4.810 | 3.5 | 24 |
| December | 4.932 | 4.950 | 4.935 | 3.5 | 24 |
| Jan., 2003 | 4.962 | 5.030 | 4.980 | 3.5 | 298 |
| February | 4.789 | 4.810 | 4.810 | 3.5 | 37 |
| March | 4.549 | 4.610 | 4.560 | 3.5 | 72 |
| April | 4.254 | 4.270 | 4.250 | 1.0 | 231 |
| May | 4.192 | — | — | 0.3 | 280 |
| June | 4.205 | — | — | 0.3 | 130 |
| July | 4.230 | — | — | 0.3 | 30 |
| August | 4.255 | 4.280 | 4.280 | 0.3 | 31 |
| September | 4.245 | — | — | 0.3 | 30 |
| October | 4.245 | — | — | 0.3 | 30 |
| November | 4.355 | — | — | 0.3 | 30 |
| December | 4.475 | 4.472 | 4.472 | 0.3 | 35 |
| Jan., 2004 | 4.515 | 4.550 | 4.512 | 0.3 | 106 |
| February | 4.395 | 4.380 | 4.380 | 0.3 | 1 |
| March | 4.255 | 4.250 | 4.240 | 0.3 | 22 |
| April | 4.113 | — | — | 0.3 | 0 |

Volume of contracts (unofficial) 45,669
Front-months open interest Monday:
May, 41,900; June, 21,783; July, 17,326
Total open interest Monday: 372,720
Weighted average of x number of trades in the last two minutes of trading. Change is from previous settlement price.

## OPTIONS
## NYMEX@Henry Hub

Results from Tuesday

| Strike | Calls-Settle | | | Puts-Settle | | |
|---|---|---|---|---|---|---|
| Price | May. | Jun. | Jul. | May. | Jun. | Jul. |
| 5.40 | — | — | — | 14.2¢ | 28.9¢ | 40.0¢ |
| 5.45 | — | — | — | 16.2¢ | 31.1¢ | 42.3¢ |
| 5.50 | — | — | — | 18.4¢ | 33.4¢ | 44.7¢ |
| 5.55 | — | — | — | 20.8¢ | 35.8¢ | 47.2¢ |
| 5.60 | 19.2¢ | 39.4¢ | 57.0¢ | — | 38.3¢ | 49.7¢ |
| 5.65 | 17.2¢ | 37.2¢ | 53.4¢ | — | — | 52.4¢ |
| 5.70 | 15.4¢ | 35.1¢ | 51.2¢ | — | — | — |
| [illegible] | 13.7¢ | 33.1¢ | 49.1¢ | — | — | — |
| [illegible] | — | — | — | — | — | — |

Estimated Volume: Calls: n/a Puts: n/a
Total open interest Monday Calls: 149,832 Puts: 206,259
Not all strike and settlement prices listed.
Implied Volatility for at-the-money strike price
Calls: n/a Puts: n/a Source: Bloomberg

## Talisman spins plan to acquire Petromet

Talisman Energy will acquire Calgary-based Petromet Resources in a cash offer at a price of C$13.20/share, representing a 26% premium over the closing price of the Petromet shares on April 9.

"This is a good marriage of assets, infrastructure and upside poter ... ia," said Talisman President and CEO Jim Buckee. "We intend to consolidat ... omet's Canadian assets into a partnership following completion of ...

"Petromet's assets tie nicely into our rapidly gr ... een building on our existing land base near the Ta ... st year with the acquisition of midstream as ... tion of properties acquired from R ...

A Talisman spokesman ... June 1, is expected to ...

With this a ... than 850 m ... 2002. P ... aid it ex ...

w ... il and liquids ... ights to more than ... drilling locations.

... x pools is approximately C$638 ... and C$1.12/mcfe (C$6.72/boe) proved ... rate more than C$250 million of cash flow in ...

... production for the remainder of 2001 at approximately 110 m ... bbl/d of liquids. More than 90% of the asset value is concentrated in two properties — Bigstone and Wild River. Petromet's average working interest in its production is 85%.

The company said it expects to mail its offer to Petromet shareholders and debenture holders on or about April 20. The offer will be conditional upon not less than two-thirds of the Petromet shares and 90% of the Petromet debentures being tendered.

Petromet's board of directors has unanimously voted to recommend acceptance of the offer by the Petromet shareholders and debenture holders. JM

## Questar signs deal for portion of Southern Trails

Questar Pipeline said it has concluded a contract with Duke Energy covering all of the capacity for the 80,000 dth/d east zone of its $155 million Southern Trails Pipeline project, a project that involves converting a crude oil pipeline to natural gas. The 705-mile pipeline runs from the Four Corners areas near Blanco, N.M., to Long Beach, Calif., and is divided into east and west zones.

The east zone can transport gas from multiple receipt points in the San Juan Basin to multiple delivery points near the California border. "This contract moves us one very large step closer to making the Southern Trails Pipeline a reality," Questar Pipeline President and CEO D.N. Rose said.

The company also is soliciting interest from customers for Southern Trails' west zone, which runs from the California state line to Long Beach. The west zone will have a capacity of 120,000 dth/d. Questar began work on the east zone last year after receiving FERC approval for the entire project last July.

The west zone is encountering regulatory and utility tariff barriers in California, similar to resistance confronted by other interstate pipelines that have tried to supply gas service into the state's market areas. Questar is proceeding with the east portion as if it were a separate project, Questar spokesman Chad Jones said. The project has received interest in the west zone from potential shippers, contingent on SoCal Gas changing its tariff to make it economically feasible to take gas from a competitive pipeline.

Questar pointed to a Residual Load Service fee imposed by SoCal Gas that "deters existing customers from using alternate natural gas suppliers if they elect to switch part of their transportation to a competing pipeline in Southern California Gas' service area."

Options that SoCal Gas has proposed in response to California Public Utilities Com-

## Michigan clicks on choice

According to the Michigan Public Service Commission, gas customers in the state are showing more interest in the state's customer choice program. As evidence, the PSC pointed to the number of times that the program information Web page has been accessed in recent months.

During March, the PSC's choice comparison of suppliers and prices page received nearly 12,000 hits. Moreover, seven other choice program-related pages were viewed an additional 16,000 times.

The increased consumer interest "will encourage expanded participation by natural gas marketers in Michigan's customer choice programs," said PSC Chairwoman Laura Chappelle. VK

## FUTURES
## NYMEX @ Henry Hub

Results from Wednesday

| | Settlement | High | Low | Change | Volume |
|---|---|---|---|---|---|
| Jun., 2001 | 4.202 | 4.315 | 4.145 | -7.7 | 0 |
| July | 4.273 | 4.385 | 4.220 | -8.0 | 0 |
| August | 4.343 | 4.450 | 4.290 | -8.2 | 0 |
| September | 4.369 | 4.465 | 4.330 | -8.6 | 0 |
| October | 4.400 | 4.500 | 4.360 | -9.3 | 0 |
| November | 4.574 | 4.674 | 4.550 | -9.9 | 0 |
| December | 4.748 | 4.855 | 4.710 | -10.5 | 0 |
| Jan., 2002 | 4.813 | 4.925 | 4.775 | -11.0 | 0 |
| February | 4.693 | 4.820 | 4.650 | -11.0 | 0 |
| March | 4.510 | 4.679 | 4.490 | -10.3 | 0 |
| April | 4.200 | 4.300 | 4.190 | -9.3 | 0 |
| May | 4.131 | 4.230 | 4.130 | -9.2 | 0 |
| June | 4.173 | 4.265 | 4.170 | -9.2 | 0 |
| July | 4.223 | 4.315 | 4.200 | -9.2 | 0 |
| August | 4.242 | 4.340 | 4.230 | -9.8 | 0 |
| September | 4.247 | 4.345 | 4.270 | -9.8 | 0 |
| October | 4.267 | 4.305 | 4.285 | -9.8 | 0 |
| November | 4.407 | 4.505 | 4.420 | -9.8 | 0 |
| December | 4.537 | 4.635 | 4.550 | -9.8 | 0 |
| Jan., 2003 | 4.587 | 4.685 | 4.600 | -9.8 | 0 |
| February | 4.442 | 4.535 | 4.475 | -9.3 | 0 |
| March | 4.255 | 4.295 | 4.287 | -9.2 | 0 |
| April | 3.970 | 4.055 | 3.995 | -8.5 | 0 |
| May | 3.935 | 3.960 | 3.930 | -8.5 | 0 |
| June | 3.975 | 3.975 | 3.975 | -8.5 | 0 |
| July | 4.025 | 4.160 | 4.160 | -8.5 | 0 |
| August | 4.070 | 4.070 | 4.070 | -7.8 | 0 |
| September | 4.087 | 4.087 | 4.087 | -7.3 | 0 |
| October | 4.102 | 4.102 | 4.102 | -6.8 | 0 |
| November | 4.214 | 4.240 | 4.230 | -6.6 | 0 |
| December | 4.349 | 4.349 | 4.349 | -6.6 | 0 |
| Jan., 2004 | 4.407 | 4.407 | 4.407 | -6.6 | 0 |
| February | 4.287 | 4.287 | 4.287 | -6.6 | 0 |
| March | 4.148 | 4.148 | 4.148 | -6.6 | 0 |
| April | 3.978 | 3.978 | 3.978 | -6.6 | 0 |
| May | 3.948 | 3.948 | 3.948 | -6.6 | 0 |
| Volume of contracts (unofficial) | | | | | 0 |

Front-months open interest Tuesday:
June, 44,175; July, 24,183; August, 28,813
Total open interest Tuesday: 409,385
Weighted average of x number of trades in the last two minutes of trading. Change is from previous settlement price.

## OPTIONS
## NYMEX@Henry Hub

Results from Wednesday

| Strike | Calls-Settle | | | Puts-Settle | | |
|---|---|---|---|---|---|---|
| Price | Jun. | Jul. | Aug. | Jun. | Jul. | Aug. |
| 4.05 | — | — | — | 11.5¢ | 22.4¢ | — |
| 4.10 | — | 41.5¢ | — | 13.6¢ | — | 30.6¢ |
| 4.15 | — | — | — | 15.8¢ | 26.7¢ | — |
| 4.20 | 17.5¢ | — | — | 18.2¢ | 29.0¢ | 35.2¢ |
| 4.25 | 16.3¢ | 33.5¢ | — | 18.5¢ | 31.5¢ | 37.5¢ |
| 4.30 | 14.2¢ | 31.1¢ | 47.5¢ | — | — | 40.0¢ |
| 4.35 | 12.4¢ | 28.9¢ | 41.5¢ | — | — | 42.5¢ |
| 4.40 | 10.7¢ | — | 39.2¢ | 27.0¢ | — | — |
| 4.45 | — | — | — | — | — | — |

Estimated Volume: Calls: n/a Puts: n/a
Total open interest Tuesday Calls: n/a Puts: n/a
Not all strike and settlement prices listed.
Implied Volatility for at-the-money strike price
Calls: 55.39% Puts: 51.32% Source: Bloomberg

## SoCal Ed presses FERC to ma' ly public

Firing off another round in the paper war over Califo uthern Califor-
nia Edison on Tuesday asked FERC for permis power study
that it says proves that El Paso and its affili o drive up
prices in the state. And the *New York Time* ty, pub-
lishing an article that focused on the uti ies.
As reported in *Gas Daily*, SoC are
blaming El Paso for alleged mar s
and capacity manipulation.
dismissed the CPUC's c of
pipeline capacity in
Now SoCal sachusetts-
based consu ioned the study,
the repo withholding capac-
ity ed to the lack of suffi-
ci ffect of raising both natural
said SoCal Ed.
ate market manipulation by El Paso
. SoCal Ed reckoned that its electricity
esult of El Paso's anticompetitive practices.
ase are concerned about the protection of sensi-
contained in case proceedings as well as in The
, FERC Chief Administrative Law Judge Curtis Wagner
ge of materials in the case.
FERC to reconsider the protected status of study. According to
the s right to know outweighs any possible confidentiality concern over material which is mere historical data, which is not contract or customer specific and which is the product of a study performed on behalf of [SoCal Ed]."

The conclusions of The Brattle Group study, however, are already circulating in public. Most recently, the *Times* ran an article that gave considerable play to The Brattle Group's findings.

El Paso has forwarded its own version of the California gas price controversy. According to a study conducted by Lukens Consulting Group and commissioned by El Paso, broader market forces were at work in driving up the price of gas in the Golden State (*GD 4/25*).

Joan Dreskin of the Interstate Natural Gas Association of America, which represents the pipeline industry, said that there should be no rush to judgement in the capacity case. "Neither the press nor the public should jump to conclusions that there was any wrongdoing by either El Paso or its marketing affiliates," she said. "There's a hearing at FERC that will review their conduct … without having all the facts, the allegations should not be decided by the press," she said. NH

## GAO prepares to investigate high gas prices

Even as gas prices fall toward the $4 mark, the investigations continue. The U.S. Congress got in on the act this week, launching a probe into the cause of high natural gas prices.

In response to several requests by members of Congress, the General Accounting Office — the investigative arm of Congress — said it would begin a search into why gas prices have risen over the past couple of years and what caused the record-high costs this past winter.

In a March 30 letter, six House representatives sent a letter to GAO Comptroller General David Walker, questioning why gas prices have risen so dramatically. The letter was signed by Reps. John Spratt, D-S.C., Jan Schakowsky, D-Ill., Bud Cramer, D-Ala., Bob Etheridge, D-N.C., Ed Markey, D-Mass., and Mike Thompson, D-Calif.

"We are alarmed at this spike in the cost of natural gas and the impact on our constituents," the letter stated.

The letter requests that the GAO investigate gas supply availability from domestic and imported production during the recent period of high prices; changes in gas demand by customer class; and the impact of increased demand for electric generation on gas prices.

In addition, the legislators asked that the GAO look into the role of trading futures on the NYMEX, gas forward contracts, and any over-the-counter derivative contracts involving gas

## Table 4. U. S. Energy Prices
(Nominal Dollars)

| | 2000 | | | | 2001 | | | | 2002 | | | | Year | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1st | 2nd | 3rd | 4th | 1st | 2nd | 3rd | 4th | 1st | 2nd | 3rd | 4th | 2000 | 2001 | 2002 |
| **Crude Oil Prices** | | | | | | | | | | | | | | | |
| Imported Average[a] | **26.84** | **26.55** | **29.11** | *28.27* | *24.57* | *24.50* | *26.00* | *27.00* | *26.33* | *26.00* | *26.50* | *26.83* | *27.72* | *25.52* | *26.41* |
| WTI[b] Spot Average | **28.82** | **28.78** | **31.61** | *31.96* | *28.82* | *27.67* | *29.04* | *30.01* | *29.34* | *29.00* | *29.50* | *29.83* | *30.29* | *28.88* | *29.42* |
| **Natural Gas Wellhead** | | | | | | | | | | | | | | | |
| (dollars per thousand cubic feet) | **2.26** | **3.06** | **3.87** | *5.22* | *6.27* | *4.50* | *4.55* | *5.40* | *5.32* | *4.42* | *4.32* | *5.18* | *3.62* | *5.18* | *4.82* |
| **Petroleum Products** | | | | | | | | | | | | | | | |
| Gasoline Retail [c] (dollars per gallon) | | | | | | | | | | | | | | | |
| All Grades | **1.44** | **1.57** | **1.56** | *1.54* | *1.47* | *1.52* | *1.53* | *1.47* | *1.46* | *1.49* | *1.49* | *1.46* | *1.53* | *1.50* | *1.47* |
| Regular Unleaded | **1.40** | **1.53** | **1.52** | *1.50* | *1.43* | *1.49* | *1.50* | *1.43* | *1.42* | *1.46* | *1.45* | *1.42* | *1.49* | *1.46* | *1.44* |
| No. 2 Diesel Oil, Retail (dollars per gallon) | **1.42** | **1.41** | **1.50** | *1.58* | *1.47* | *1.41* | *1.42* | *1.46* | *1.43* | *1.42* | *1.42* | *1.45* | *1.48* | *1.44* | *1.43* |
| No. 2 Heating Oil, Wholesale (dollars per gallon) | **0.85** | **0.78** | **0.91** | *0.97* | *0.84* | *0.74* | *0.77* | *0.86* | *0.83* | *0.76* | *0.77* | *0.85* | *0.88* | *0.81* | *0.81* |
| No. 2 Heating Oil, Retail (dollars per gallon) | **1.31** | **1.17** | **1.23** | *1.40* | *1.34* | *1.18* | *1.12* | *1.27* | *1.28* | *1.17* | *1.12* | *1.26* | *1.31* | *1.28* | *1.24* |
| No. 6 Residual Fuel Oil, Retail [d] (dollars per barrel) | **23.64** | **24.55** | **25.10** | *27.40* | *24.52* | *23.35* | *23.79* | *25.53* | *25.02* | *23.38* | *23.61* | *24.62* | *25.34* | *24.30* | *24.14* |
| **Electric Utility Fuels** | | | | | | | | | | | | | | | |
| Coal (dollars per million Btu) | **1.21** | **1.21** | **1.18** | *1.20* | *1.21* | *1.22* | *1.20* | *1.20* | *1.20* | *1.21* | *1.19* | *1.18* | *1.20* | *1.21* | *1.20* |
| Heavy Fuel Oil [e] (dollars per million Btu) | **3.74** | **4.18** | **4.34** | *4.46* | *3.82* | *3.83* | *3.97* | *4.07* | *3.88* | *3.84* | *3.94* | *3.95* | *4.25* | *3.90* | *3.90* |
| * Natural Gas (dollars per million Btu) | **2.85** | **3.78** | **4.46** | *5.91* | *6.91* | *5.15* | *5.16* | *6.02* | *6.02* | *5.03* | *4.92* | *5.79* | *4.25* | *5.61* | *5.27* |
| **Other Residential** | | | | | | | | | | | | | | | |
| Natural Gas (dollars per thousand cubic feet) | **6.53** | **7.77** | **10.09** | *8.68* | *9.91* | *10.58* | *11.04* | *9.12* | *9.47* | *10.12* | *11.02* | *9.35* | *7.69* | *9.88* | *9.65* |
| Electricity (cents per kilowatthour) | **7.78** | **8.37** | **8.59** | *8.21* | *7.97* | *8.56* | *8.81* | *8.35* | *7.98* | *8.54* | *8.81* | *8.33* | *8.25* | *8.44* | *8.43* |

[a] Refiner acquisition cost (RAC) of imported crude oil.
[b] West Texas Intermediate.
[c] Average self-service cash prices.
[d] Average for all sulfur contents.
[e] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the fourth quarter of 2000. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

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(Nominal Dollars)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1st | 2nd | 3rd | 4th | 1st | 2nd | 3rd | 4th | 1st | 2nd | 3rd | 4th | 2000 | 2001 | 2002 |
| **Crude Oil Prices** | | | | | | | | | | | | | | | |
| Imported Average[a] | 26.84 | 26.55 | 29.12 | 28.25 | 24.57 | 25.00 | 27.00 | 27.00 | 26.33 | 26.00 | 26.50 | 26.83 | 27.72 | 25.91 | 26.41 |
| WTI[b] Spot Average | 28.82 | 28.78 | 31.61 | 31.96 | 28.82 | 28.44 | 30.14 | 30.04 | 29.34 | 29.00 | 29.50 | 29.83 | 30.29 | 29.36 | 29.42 |
| **Natural Gas Wellhead** | | | | | | | | | | | | | | | |
| (dollars per thousand cubic feet) | 2.26 | 3.06 | 3.87 | 5.22 | 6.27 | 4.57 | 4.73 | 5.52 | 5.38 | 4.48 | 4.36 | 5.19 | 3.62 | 5.27 | 4.86 |
| **Petroleum Products** | | | | | | | | | | | | | | | |
| Gasoline Retail [c] (dollars per gallon) | | | | | | | | | | | | | | | |
| All Grades | 1.44 | 1.57 | 1.56 | 1.54 | 1.47 | 1.66 | 1.61 | 1.53 | 1.48 | 1.51 | 1.50 | 1.47 | 1.53 | 1.57 | 1.49 |
| Regular Unleaded | 1.40 | 1.53 | 1.52 | 1.50 | 1.43 | 1.62 | 1.58 | 1.50 | 1.44 | 1.48 | 1.47 | 1.44 | 1.49 | 1.53 | 1.46 |
| No. 2 Diesel Oil, Retail (dollars per gallon) | 1.42 | 1.41 | 1.50 | 1.58 | 1.47 | 1.47 | 1.48 | 1.49 | 1.45 | 1.43 | 1.43 | 1.46 | 1.48 | 1.48 | 1.44 |
| No. 2 Heating Oil, Wholesale (dollars per gallon) | 0.85 | 0.78 | 0.91 | 0.97 | 0.83 | 0.75 | 0.80 | 0.86 | 0.84 | 0.76 | 0.77 | 0.85 | 0.88 | 0.82 | 0.81 |
| No. 2 Heating Oil, Retail (dollars per gallon) | 1.31 | 1.17 | 1.23 | 1.40 | 1.35 | 1.19 | 1.15 | 1.28 | 1.29 | 1.18 | 1.12 | 1.26 | 1.31 | 1.28 | 1.25 |
| No. 6 Residual Fuel Oil, Retail [d] (dollars per barrel) | 23.62 | 24.57 | 25.10 | 27.41 | 24.99 | 24.52 | 25.22 | 26.27 | 25.57 | 23.83 | 23.90 | 25.24 | 25.34 | 25.26 | 24.64 |
| **Electric Utility Fuels** | | | | | | | | | | | | | | | |
| Coal (dollars per million Btu) | 1.21 | 1.21 | 1.18 | 1.20 | 1.21 | 1.23 | 1.21 | 1.20 | 1.21 | 1.22 | 1.19 | 1.18 | 1.20 | 1.21 | 1.20 |
| Heavy Fuel Oil [e] (dollars per million Btu) | 3.74 | 4.18 | 4.34 | 4.52 | 3.90 | 4.02 | 4.20 | 4.18 | 3.97 | 3.91 | 3.98 | 4.03 | 4.27 | 4.05 | 3.97 |
| Natural Gas (dollars per million Btu) | 2.85 | 3.78 | 4.46 | 6.33 | 7.61 | 5.62 | 5.56 | 6.24 | 6.14 | 5.11 | 4.97 | 5.81 | 4.33 | 6.03 | 5.33 |
| **Other Residential** | | | | | | | | | | | | | | | |
| Natural Gas (dollars per thousand cubic feet) | 6.53 | 7.77 | 10.09 | 8.68 | 9.91 | 10.59 | 11.12 | 9.26 | 9.58 | 10.20 | 11.08 | 9.39 | 7.69 | 9.93 | 9.73 |
| Electricity (cents per kilowatthour) | 7.76 | 8.35 | 8.57 | 8.26 | 8.10 | 8.79 | 9.00 | 8.50 | 8.11 | 8.63 | 8.87 | 8.38 | 8.25 | 8.61 | 8.51 |

[a] Refiner acquisition cost (RAC) of imported crude oil.

[b] West Texas Intermediate.

[c] Average self-service cash prices.

[d] Average for all sulfur contents.

[e] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the fourth quarter of 2000. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Non-OPEC production is expected to increase by another 0.6 million barrels per day in 2001, with much of this increase coming from Russia. Although the Caspian Pipeline Consortium has begun filling its new pipeline to transport oil from Kazakhstan to world markets, this is not expected to support greater Caspian production levels until end-2001.

**International Oil Demand.** World oil demand remains expected to grow, despite concerns over a gradual economic slowdown in the industrialized countries. EIA projects world oil demand growth of 1.4 million barrels per day in 2001 (higher than the IEA's 1.3 million barrels per day prediction), with slightly higher demand growth expected for 2002. Besides the OECD, non-OECD Asia is still expected to be the leading region for oil demand growth over the next two years, although this growth now appears to be weaker than previously assumed.

**World Oil Inventories.** EIA does not attempt to estimate oil inventory levels on a global basis. However, the direction in which global oil inventories are headed is discerned from EIA's world oil supply and demand estimates. Stocks are currently below "normal" levels, although not by so wide a margin as EIA previously believed, and these low inventory levels are expected to put upward pressure on prices. U.S. crude oil stocks, for example, are expected to remain below normal levels for most of 2001 and to improve in 2002 but only into the lower end of the normal range (Figure 9).

**U. S. Energy Prices**

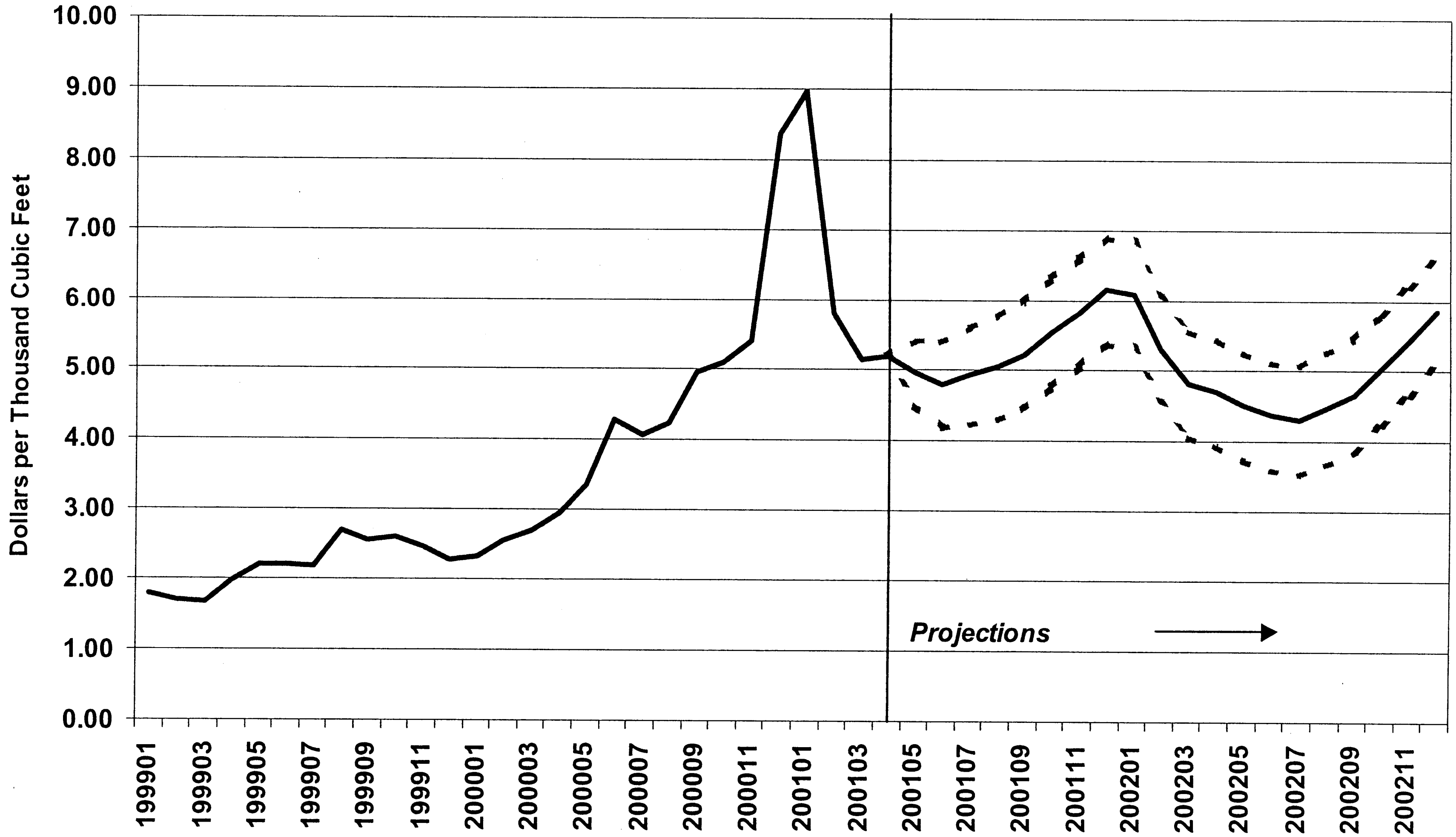
**Motor Gasoline.** As noted above, pump prices have been soaring due to high demand and low inventories. The tightening of motor gasoline stocks, which are less plentiful now than they were this time last year and have helped push prices into new territories.

As a result, we project that the average monthly pump price for regular gasoline will range between $1.50 and $1.75 per gallon, perhaps more, during the peak months of the driving season. Last year, the high national average prices were skewed by exceedingly high pump prices in the Midwest (over $2.00 per gallon at times), which, in turn, were the result of critical regional supply problems. Although in our base case we do not necessarily project a repeat of last year, the current situation of relatively low inventories for gasoline sets the stage for potential regional imbalances in supply that could bring about significant price volatility in the U.S. gasoline market.

**Distillate Fuel Oil (Diesel and Heating Oil).** The recent surge in motor gasoline prices may impact the retail price of diesel fuel oil. Since there is currently a supply deficit for motor gasoline, refiners will need to emphasize gasoline production at the expense of distillate. Even though inventories of distillate fuel are adequate, supplies of this fuel may become tighter during the summer as distillate production lags, resulting in a premium for its price. As a result, retail diesel prices are expected to remain fairly high in historical terms, averaging close to $1.50 per gallon during the driving season. Moreover, consumption of distillate fuel in place of natural gas for power generation could put additional pressure on the diesel fuel market, although such a development is rather unlikely unless electricity demand surges sharply in key gas-consuming regions.

**Natural Gas.** Last winter (October 2000-March 2001) natural gas prices at the wellhead averaged $5.74 per thousand cubic feet, more than double the previous winter's price. Natural gas prices (Figure 10) began climbing last summer primarily in response to low levels of underground gas storage. Compared to this time last year, storage levels are still low. As a result, spot prices are currently averaging about $5.00 per thousand cubic feet. We continue to believe that, given the current state of the natural gas market, it will be a while before prices at the wellhead return to the low level of $2.00 per thousand cubic feet experienced just one year ago. About 90 percent of the planned additions to electric generating capacity over the next few years are designed to primarily use natural gas as a fuel source. For the spring and summer, average

# Figure 10. Natural Gas Spot Prices
## (Base Case and 95% Confidence Interval )




Sources: History: Natural Gas Week; Projections: Short-Term Energy Outlook, May 2001.

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wellhead prices are projected to decline only modestly, averaging an unseasonably strong $4.65 per thousand cubic feet. One factor that should keep prices relatively high is the need for unusually large refill volumes for underground storage. The gas supply situation this injection season bears close monitoring. If the spring and summer weather is particularly hot in regions that consume large quantities of gas-fired electricity, (California and Texas for example), then injections into underground storage for the next winter would again be strained, resulting once more in sharply rising prices from already robust current levels. In 2001, the annual average wellhead price is projected to average over $5.00 per thousand cubic feet. Next year, we expect the storage situation to improve somewhat and with that, we expect a dip in the average annual wellhead price. Increases in production and imports of natural gas needed to keep pace with the rapidly growing demand for natural gas will be accompanied, for the time being, by relatively expensive supplies for gas due to rising production costs and capacity constraints on the pipelines.

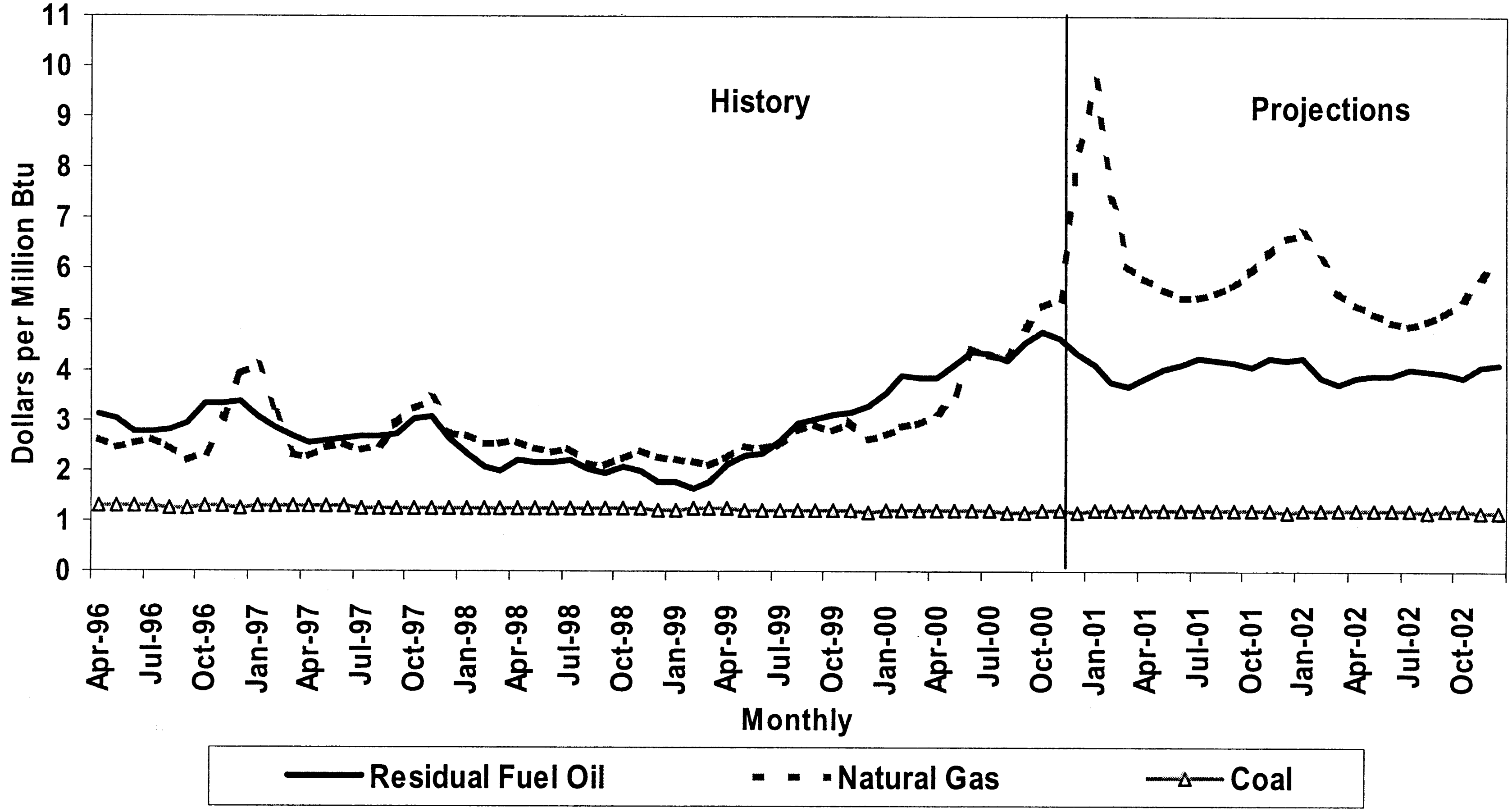
**Electric Utility Fuels**. The rapid rise in gas prices last summer and fall has pulled delivered gas prices above heavy fuel oil prices on a cost per Btu basis (Figure 11). As this situation is likely to persist, we anticipate some recovery in the amount of heavy fuel oil used for power generation over the very low levels seen since late 1999. In 2001, the cost of coal to electric utilities is projected to increase slightly, after years of slow but continual decline, as coal, like oil, is being used more intensively for electricity generation in lieu of expensive or unavailable natural gas. On an inflation-adjusted basis, however, coal prices should still show a decline this year.

## U.S. Oil Demand

Petroleum demand data for 2000 have been revised. (The more detailed view of the revisions is provided in EIA's latest *Petroleum Supply Monthly*). Compared to previous Short-Term Energy Outlook, these revisions, brought about primarily by revisions to imports data, result in an overall 0.9-percent increase in total estimated demand in 2000 compared to the preliminary figures. As a result, total demand increased from 19.52 million barrels per day in 1999 to 19.68 million barrels per day in 2000, an increase of 0.8 percent. This contrasts with a 0.1-percent decline based on the original data. The demand revisions involved upward adjustments in most major product categories. In contrast to the 0.6-percent decline based on the original data, motor gasoline demand now exhibits a 0.5-percent growth rate from the 1999 level, a revision of 1.1 percent. The year-to-year increase in jet-fuel demand has been revised from 2.0 percent to 3.2 percent. In addition, distillate fuel and residual fuel oil demands registered increases of 3.4 and 9.4 percent, up from 3.2 and 1.8 percent based on the preliminary data. The liquefied petroleum products group also underwent an increase but the year-to-year change was still slightly negative. Other minor petroleum products generally registered downward revisions. In general, these revisions reduce the responsiveness to price change that one may reasonably attribute to the petroleum demand weakness witnessed in 2000. As it turns out, the numbers now line up somewhat better, on balance, with the sorts of results one would expect using the short-run price elasticities embedded in the model used for the Short-Term Energy Outlook. However, these elasticities have always been small in absolute value, so the change is not one that is particularly worrisome from the standpoint of consistency with accumulated experience.

Total petroleum products demand is projected to climb an average 250,000 barrels per day, or 1.3 percent, in 2001. Data for the first quarter of this year indicate a sizable year-to-year 510,000 barrels-per day, or 2.6-percent, increase in total petroleum demand. But much of that increase stems from special factors. The most important is the weather, which, although only moderately colder than normal, was more than 11 percent colder in terms of heating degree-days than during the mild winter quarter of 2000. Weather contributed to the 11-percent growth distillate fuel oil demand compared to the same quarter last year. An additional factor was the change in relative prices brought about by the unprecedented spike in natural gas prices, which, in combination with the cold weather, helped boost residual fuel oil demand by 25 percent. Another factor was the concern about the possible impact of Y2K, which boosted deliveries in December, 1999, but depressed shipments in January, 2000.

# Figure 11. Fossil Fuel Prices to Electric Utilities




Sources: History: EIA; Projections: Short-Term Energy Outlook, May 2001.

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U.S. natural gas demand is expected to grow at about a 1.9-percent rate this year, following the strong 4.9-percent performance in 2000 (Figure 14). A slowing economy and less rapid demand growth in the industrial and commercial sectors are the reasons. Growth in 2002 is expected to heat up to about 3.4 percent as the economy picks up again and as new gas-fired power generation requirements continue to mount.

Domestic gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling experienced over the past year. Production is estimated to have risen by 3.7 percent in 2000 and it is forecast to continue to increase by 2.7 percent rate in 2001 and 2.5 percent in 2002.

Based on EIA survey data and recent information from the American Gas Association on early-season storage additions, we estimate that, on an EIA survey basis, working gas in storage at the end of April was 932 billion cubic feet (bcf) (Figure 15). It is a measure of the sensitivity of the gas market to developments this year concerning the progress of storage additions that recent spot prices and near futures have slipped to below $5.00 per thousand cubic feet (mcf) from recent peaks as high as $5.73 per mcf at the Henry Hub on April 11. The very large storage injections still expected for the summer may yet play a role in strengthening gas prices over the next few months, particularly if very hot temperatures and above-normal cooling demand appear in regions that use large amounts of gas for power generation and heightens the competition for gas between current and future demand sources.

Net imports of natural gas are projected to rise by about 13 percent in 2001 and by another 4 percent in 2002. For this summer, we project that natural gas imports will be 17 percent above last summer's as demand for storage refill is expected to be high.

**Electricity Demand and Supply**

Total annual electricity demand growth (retail sales plus industrial generation for own use) is projected at about 2.3 percent in 2001 and 2.1 percent in 2002. This is compared with estimated demand in 2000 that was 3.6 percent higher than the previous year's level. Electricity demand growth is expected to be slower in the forecast years than it was in 2000 partly because economic growth is also slowing from its higher 2000 level.

This summer's overall cooling degree-days (CDD) are projected to be normal, or about 1.0 percent below last summer's CDD total. Summer electricity demand is expected to be 2.6 percent higher than last summer based mainly on economic factors, i.e., rising GDP, albeit less rapid than last year, higher housing stocks and employment (Figure 16 and Table 10).

Hydropower generation in the crucial Pacific Northwest is expected to be down by 7.5 percent from last summer, due mainly to lower water levels. According to the National Oceanic and Atmospheric Association (NOAA), this winter was the second driest winter on record, after the 1976/77 winter. In addition, the crisis in California this winter has further drained reservoirs, depriving the region of generation resources for this spring and summer. Nuclear generation is also expected to be 5.6 percent lower than last summer mainly due to scheduled maintenance outages.

A total of 23,558 megawatts of new total electricity generating capacity was added in 2000. Based on accumulated public announcements (including wire reports, news articles and company press releases) over the past year, an estimated 40,000 to 50,000 megawatts of new capacity is planned for installation annually in 2001 and 2002. EIA's power plant surveys suggest that closer to 25,000 megawatts of new capacity will be installed annually in 2001 and in 2002. The table below shows the regional distribution of these capacity increases.

# PRICE HEDGING REPORT

A Weekly Supplement to *Gas Daily*

## Longs dispelled by shorts

The bears were on the prowl last week as the May contract neared expiration. Short positions dramatically increased, creating the reality of a deteriorating market. As summer begins to heat things up, though, prices could follow suit, sources say.

Short positions overtook long positions at an unusually large margin of more than three to one in the Commodity Futures Trading Commission's latest Commitments of Traders Report for the week ending April 24.

Short positions increased considerably last week, jumping to 14,524, compared to the prior week's report of 10,481. Long positions remained virtually unchanged coming in at 4,430 from last week's 4,137.

Spreading positions also increased slightly with the current report, showing 13,771, compared to the previous report of 13,630. Overall open interest increased to 388,716 from 385,794.

As the May contract approached expiration, a daily erosion of the screen began to take shape, sending prices below key support levels on Thursday and ultimately resulting in the May contract settling at $4.891 upon expiration.

The reason for the slump in prices appeared fundamentally based, as mild weather forecasts persist. In addition, a moderately bearish American Gas Association injection estimate also happened to coincide with the usual pre-expiration liquidations, adding fuel to the sell-off.

Even though the week ended with prices trending downward into the $4.80s, some traders believe that gas prices have possibly hit bottom for the rest of the year.

"A little over a week ago, $5 was considered an attractive buy, so now that we are below $5, we should begin to see a flurry of activity as the June contract begins to actively trade," a futures trader said.

"Summer heat is just around the corner, hurricane season begins in just a month from now, and to top it all off, we will be seeing a substantial increase in the number of gas-fired power generation plants coming online. It all adds up to the likelihood of higher prices to come, from what I can see," the trader said. AL

### Commitments of Traders

This table shows long, short and spread positions of non-commercials, as reported weekly to the CFTC.

| Rpt. Date | Long | Short | Spreading |
|---|---|---|---|
| 24-Apr | 4,430 | 14,524 | 13,771 |
| 17-Apr | 4,137 | 10,471 | 13,630 |
| 10-Apr | 5,908 | 7,693 | 11,911 |

## Traders fear winter price repeat at Sumas

With traders coughing up more than $40/mmBtu for gas at Sumas, Wash., last December, players find themselves this spring attempting to hedge off any repeats of those bad memories.

One source said trying to determine what Sumas prices will do next winter is very difficult. "Weather and demand are big factors. And then there's the uncertainty of when Northwest Pipeline will call an operational flow order at Kemmerer, Wyo.," the source said.

He said constraints on northbound gas out of Wyoming on Northwest forced traders to buy Sumas gas last winter, helping drive the price up there. "That forced a lot of people to buy Sumas gas when they normally wouldn't buy there. If people try to shove gas through the constrained points like they did last year, we'll definitely see expensive gas again."

Because temperatures plunged so early last winter, there were strong storage draws in the Pacific Northwest and Rockies that led to storage worries for the rest of the season, another trader said. And California's power woes started around the same time.

"All of that combining is why we saw $40 gas," the source said. "If all that happens again, we'll see a return of $40 gas."

California's energy crisis will once again have an impact on Sumas price direction next winter, another source said. "If Southern California Gas goes to $40, Malin and Sumas will go there too. It's not just a point-by-point problem. It's a western region problem. A lot of these markets are connected."

To hedge themselves against that kind of volatility for the upcoming winter, most traders are working the November-to-March strip. "Sumas is trading at a small discount to Malin right now," one trader said. "Anywhere from 40¢ to $1.10 over the last few months."

Even though there is a certain spread, there is a big premium to the physical molecule in the wintertime. People trade financially to lock in positions, but if they want to convert to a physical position they pay big dollars, he added. "Physical molecules will create the Btus, not the financial paper," he explained.

Utilities have to make sure they are covered against the big price spikes too, no matter what factors enter the picture, a source said. "As a utility, we probably do more hedging than a marketer. We typically do it every year and not because of what happened last year at Sumas," the utility source said. SS

## N. American rig count stable

After two weeks of big drops, the Canadian rig count stayed relatively flat last week at 188. The number of rigs exploring for oil and gas in Canada had dropped a total of 80 in the previous two reports released by Baker Hughes.

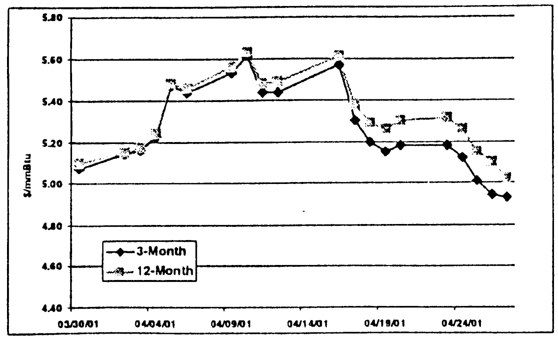
The U.S. rig count remained about the same, as well. The number of rigs exploring for oil and gas stood at 1,212 last week, down one from the previous count.

For all of North America, the oil and gas rig count dropped one to 1,400. RW

## Henry Hub Futures and Strips

This table shows selected NYMEX Henry Hub contract settlement prices from the past week and calculates the 3-, 6-, 9-, and 12-month spreads. The chart to the right of the table data shows strip movement over the past 20 trading days. A dash indicates no data; an H indicates a holiday.

| | 04/23 Mon | 04/24 Tue | 04/25 Wed | 04/26 Thu | 04/27 Fri |
|---|---|---|---|---|---|
| May-01 | 5.125 | 5.078 | 4.981 | 4.891 | - |
| Jun-01 | 5.175 | 5.114 | 4.994 | 4.940 | 4.867 |
| Jul-01 | 5.240 | 5.177 | 5.057 | 5.002 | 4.935 |
| Aug-01 | 5.298 | 5.232 | 5.110 | 5.055 | 4.990 |
| Sep-01 | 5.310 | 5.245 | 5.125 | 5.070 | 5.010 |
| Oct-01 | 5.338 | 5.275 | 5.155 | 5.102 | 5.045 |
| Nov-01 | 5.482 | 5.420 | 5.300 | 5.252 | 5.198 |
| Dec-01 | 5.618 | 5.562 | 5.450 | 5.402 | 5.354 |
| Jan-02 | 5.672 | 5.617 | 5.507 | 5.462 | 5.415 |
| Feb-02 | 5.512 | 5.462 | 5.357 | 5.317 | 5.275 |
| Mar-02 | 5.242 | 5.205 | 5.115 | 5.086 | 5.050 |
| Apr-02 | 4.792 | 4.749 | 4.665 | 4.646 | 4.620 |
| 3/strip | 5.180 | 5.123 | 5.011 | 4.944 | 4.930 |
| 6/strip | 5.248 | 5.187 | 5.070 | 5.010 | 5.007 |
| 9/strip | 5.362 | 5.302 | 5.187 | 5.131 | 5.121 |
| 12/strip | 5.317 | 5.261 | 5.151 | 5.102 | 5.022 |



**Daily Price Survey** continued

| Trans. date | 5/9 | 5/9 | 5/9 |
|---|---|---|---|
| Flow date(s) | 5/10 | 5/10 | 5/10 |
| | Midpoint | Absolute | Common |
| **New Mexico-San Juan Basin** | | | |
| El Paso, Bondad | 3.615 | 3.50-68 | 3.57-66 |
| El Paso, non-Bondad | 3.630 | 3.50-75 | 3.57-69 |
| TW (Ignacio, pts south) | — | — | — |
| TW SJ (Blanco) | — | — | — |
| **Rockies** | | | |
| CIG (N. syst) | 3.470 | 3.16-65 | 3.35-59 |
| Kern River/Opal plant | 3.610 | 3.38-74 | 3.52-70 |
| NW, Stanfield | 4.170 | 4.05-25 | 4.12-22 |
| Questar | 3.570 | 3.40-72 | 3.49-65 |
| Cheyenne Hub | 3.700 | 3.38-82 | 3.59-81 |
| NW, Wyoming Pool | 3.570 | 3.50-69 | 3.52-62 |
| NW, south of Green River | 3.465 | 3.15-65 | 3.34-59 |
| **Canadian Gas** | | | |
| Iroquois | 4.400 | 4.37-41 | 4.39-41 |
| Niagara (NFG, Tenn) | 4.395 | 4.37-43 | 4.38-41 |
| NW Sumas | 4.060 | 3.96-4.12 | 4.02-10 |
| NOVA (AECO-C, NIT)* | C5.665 | C5.62-69 | C5.65-68 |
| NOVA (same-day)***** | C5.635 | 5.58-68 | 5.61-66 |
| Emerson (Viking/GL) | 4.100 | 4.05-17 | 4.07-13 |
| Dawn, Ont. | 4.405 | 4.38-44 | 4.39-42 |
| PG&E-GTNW (Kingsgate) | 4.000 | 3.99-4.01 | 3.99-4.01 |
| Westcoast, St. 2* | C5.745 | C5.67-77 | C5.72-77 |
| **Appalachia** | | | |
| Dominion North Point | 4.380 | 4.36-40 | 4.37-39 |
| Dominion South Point | 4.395 | 4.34-51 | 4.35-44 |
| Columbia, App | 4.345 | 4.29-43 | 4.31-38 |
| **Mississippi-Alabama** | | | |
| FGT, Mobile Bay | 4.025 | 4.00-05 | 4.01-04 |
| Gulf South, Mobile Bay | 3.990 | 3.95-4.03 | 3.97-4.01 |
| Texas E., M-1 (Kosi) | 4.235 | 4.20-27 | 4.22-25 |
| Transco, St. 85 | 4.150 | 4.12-20 | 4.13-17 |
| **Others** | | | |
| Algonquin | 4.470 | 4.46-48 | 4.46-48 |
| SoCal gas, large pkgs*** | 12.430 | 12.00-95 | 12.19-67 |
| PG&E, large pkgs*** | 8.305 | 7.50-8.85 | 7.97-8.64 |
| Kern River Station | — | — | — |
| Malin | 4.605 | 4.25-95 | 4.43-78 |
| Alliance (into Interstates) | 4.205 | 4.18-24 | 4.19-22 |
| ANR ML7 (entire zone) | 4.405 | 4.36-49 | 4.37-44 |
| NGPL Amarillo receipt | 4.065 | 4.02-12 | 4.04-09 |
| NGPL Iowa-Ill. receipt | 4.095 | 4.03-16 | 4.06-13 |
| Northern (Mid 13) | 3.790 | 3.77-81 | 3.77-81 |
| Northern (Ventura) | 4.055 | 4.01-15 | 4.02-09 |
| Northern (demarc) | 4.050 | 4.00-15 | 4.01-09 |
| Dracut (into TN) | 4.335 | 4.30-44 | 4.30-37 |
| **Citygates** | | | |
| Chicago-LDCs, large e-us | 4.230 | 4.14-30 | 4.19-27 |
| Mich.-Consum. Energy** | 4.355 | 4.32-42 | 4.33-38 |
| Mich.-Mich Con** | 4.345 | 4.30-41 | 4.32-37 |
| PSCo citygate | 3.515 | 3.33-67 | 3.43-60 |
| PG&E citygate | 8.295 | 7.40-9.10 | 7.87-8.72 |
| Northwest (all gates) | 4.160 | 4.15-22 | 4.15-17 |
| Florida gates via FGT | 4.465 | 4.40-51 | 4.44-49 |
| Algonquin citygates | 4.505 | 4.42-56 | 4.47-54 |
| Dominion (delivered) | 4.580 | 4.57-59 | 4.57-59 |
| Columbia Gas (delivered) | 4.550 | 4.54-56 | 4.54-56 |
| Tenn. zone 5 | 4.450 | 4.42-46 | 4.44-46 |
| Tenn. zone 6 (delivered) | 4.440 | 4.41-49 | 4.42-46 |
| Iroquois, Zone 2 | 4.465 | 4.45-48 | 4.46-47 |
| Texas E., M-3 | 4.490 | 4.41-60 | 4.44-54 |
| Transco Z6 (non-NY) | 4.480 | 4.41-60 | 4.43-53 |
| Transco Z6 (NY) | 4.515 | 4.45-62 | 4.47-56 |

***NOTE: Price in C$ per gj; C$1=US$0.64918 (Canadian currency settlement from one business day prior EST.) **Large end-user prices. ***Deliveries into SoCal at Topock, Blythe, Needles, Ehrenburg; deliveries into PG&E at Topock and Daggett. ****Volume-weighted for all points except AECO-C and Westcoast St. 2. *****The NOVA (same-day) midpoint and ranges are for flow on the transaction date.**

willingness to absorb both positive and negative financial performance."

In first quarter 2001, TransCanada's gas marketing operation took a major hit supplying gas under a contract with a Midwest utility that calls for lower than market prices. The effects of that contract and the costs of exiting the retail gas business caused the unit to record a C$6 million loss for the quarter. In the 2000 first quarter, the marketing unit reported C$10 million in earnings.

Gas marketing revenues grew by some C$4.5 billion in the first quarter compared to last year, mostly due to higher gas prices.

TransCanada said it had considered other options for the business, such as refocusing and downsizing, but decided it would be more valuable if it was divested as a going concern to "a more appropriate owner."

"We recognize our employees bring the most value to the gas marketing business, so we will negotiate with prospective buyers to maximize opportunities for these employees," Kvisle said. "We will work with all affected employees to ease their transition through the process." SGS

## Low storage levels to keep gas prices high

Due to the low level of underground gas storage and strong demand for natural gas to fuel electricity generation, the Energy Information Administration expects gas prices to remain high until at least next year.

For this spring and summer, gas prices are projected to decline modestly. In 2001, annual gas prices will average more than $5, EIA stated in its Short-Term Energy Outlook. If the spring and summer are hot in regions that consume large quantities of gas, the injections into underground storage would again be strained, resulting in a rise in prices again next winter.

The outlook "reaffirm[s] the need to develop additional sources of energy while building and maintaining the necessary infrastructure to more those supplier to the market," said Energy Secretary Spencer Abraham. "Until we take steps to address these problems, we will continue to experience volatility in energy markets and higher prices passed on to consumers at the gas pump."

Domestic gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling over the past year, EIA said. The growth rates are projected to be 2.7% in 2001 and 2.5% in 2002, compared to 3.7% in 2000.

Very large storage injections are still expected for this summer. The storage situation, said EIA, is expected to improve next year, however, driving prices down.

A slowing economy and less rapid demand growth in the industrial and commercial sectors would decrease the gas demand in 2001 to about 1.9%, as compared to the high growth rate of 4.9% seen in 2000. Growth in 2002 is expected to be about 3.4% as the economy picks up again.

Net imports for gas are projected to rise about 13% in 2001 and another 4% in 2002. For the coming summer season, EIA projected that gas imports will be 17% above last summer's as demand for storage refill is likely to be high. VK

## BP chooses Tampa as site for LNG terminal

The city of Tampa, Fla., has the potential to become one of the great energy hubs in North America as the result of Gulfstream Natural Gas System coming onshore in the area as well as BP's plans to build a $200 million import terminal in the Port of Tampa, BP North America Gas and Power President Tony Fountain said yesterday at GasMart/Power in Tampa.

Crude oil and coal already have a strong presence in Tampa because of its major port. "As for us, we're very keen that this is going to become one of the great [liquefied natural gas] hubs.

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BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-16)

powermarketers.com BREAKING NEWS

# Cascade Natural Gas Receives Approval to Stabilize Rates

PR Newswire ( November 02, 2001 )

SEATTLE, Nov. 2 /PRNewswire/ -- Cascade Natural Gas Corporation (NYSE: CGC) received Washington Utilities and Transportation Commission (WUTC) approval for its Purchased Gas Cost Adjustment (PGA) and amortization of under-recovered gas cost from last winter filings. As a result of these two filings, Cascade's residential customers will see a net rate increase of 2.2%, 1.9% for the average commercial customer, and 2.1% for the average industrial customer, effective November 1, 2001. Cascade will recover last winter's gas cost over the next three years.

Jon Stoltz, Senior Vice President of Regulatory and Consumer Affairs stated, "In order to shield our customers from the price spikes that can occur in a volatile wholesale market, Cascade developed a strategy of locking in the quantity and price of the natural gas requirements of our customers for the next three years. By locking in the price of the supply, we can assure our customers that our rates will not significantly change and by locking in the quantity of supply, we can assure our customers that there will be adequate natural gas available to meet their needs. The fixed priced contracts will help us avoid an under-recovery situation similar to what occurred last winter."

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-17)

FT FINANCIAL TIMES Energy

Megawatt Daily's **Market Report**

Monday, December 11, 2000

Indexes and Transaction Record for 12/11/00

## Explanations

**Index** — Volume-weighted average of all trades reported.
**Absolute Low** — Lowest trade reported.
**Absolute High** — Highest trade reported.
**Trading Volume Reported** — Volume of trades per hour for each of 16 peak hours. This figure is a total of all trading volume reported to MWD for each delivery site; because every effort is made to capture both sides of every deal reported, MWD recognizes that this figure includes duplicate volumes, and the figure should be used as a trend indicator not necessarily as an indicator for transmitted volumes.
**Total Peak Volume** — Volume for all peak hours, found by multiplying the trading volume by 16.
**Number of Trades** — This figure is calculated by dividing the trading volume reported by 50 MW/h for all Central and East listings; numbers of trades for delivery points in the West are calculated by dividing by 25 MW/h.

## Methodology

The prices displayed in the table to the right are for power, in $/MWh, traded at the delivery points and regions listed. Peak hours are 0600-2200 hrs.; PJM and New York peak hours are 0700-2300. Off-peak hours generally start at 2200 hrs. on the date before the delivery date and end at 0600 on the delivery date. Not included are 24-hour deals categorized in some NERC regions as off-peak hours over Saturdays and Sundays. Transactions at the hubs listed in the separate table at the top of this page are financially firm. Deals at other locations may be unit-firm or system-contingent, and may include capacity reservation charges. Transactional data is gathered from utilities, marketers, co-ops, brokers, municipals and government power agencies. Deals done in the West are excluded if done after 1015 hrs. PT; deals done in the East and Central areas are excluded if done after 1100 hrs. CT. The middle column is the volume-weighted average of all deals reported and should be used for indexing purposes. The common range represents pricing for most of the trading volume; the absolute range represents lowest and highest prices reported. Copyright 2000 by Financial Times Energy.

## Trades for Standard 16-Hour Daily Products; *all prices and volumes in $/MWh*

| Delivery Point | Weighted Average Index | Absolute Low | Absolute High | Trading Volume Reported | All Peak Hours Volume | Number of Trades Reported |
|---|---|---|---|---|---|---|
| **West** | | | | | | |
| COB | $3,000.00 | $3,000.00 | $3,000.00 | 25 | 400 | 1 |
| Four C | — | — | — | 0 | 0 | 0 |
| Mead, Nev. | — | — | — | 0 | 0 | 0 |
| Mid-Columbia | $4,175.00 | $3,000.00 | $5,000.00 | 100 | 1,600 | 4 |
| NP15 | — | — | | 0 | 0 | 0 |
| Palo Verde | $395.00 | $360.00 | $425.00 | 75 | 1,200 | 3 |
| SP15 | $350.00 | $350.00 | $350.00 | 25 | 400 | 1 |
| **Central** | | | | | | |
| ERCOT-B | $65.59 | $60.00 | $75.00 | 850 | 13,600 | 17 |
| Ameren | — | — | — | 0 | 0 | 0 |
| Com Ed, into | $44.39 | $40.00 | $52.00 | 900 | 14,400 | 18 |
| MAIN North | $63.33 | $58.00 | $120.00 | 300 | 4,800 | 6 |
| MAIN South | — | — | — | 0 | 0 | 0 |
| MAPP North | $60.94 | $50.00 | $75.00 | 160 | 2,560 | 3 |
| MAPP South | — | — | — | 0 | 0 | 0 |
| Entergy, into | $67.40 | $50.00 | $76.00 | 2,000 | 32,000 | 40 |
| SPP | $65.90 | $58.00 | $75.00 | 500 | 8,000 | 10 |
| **East** | | | | | | |
| Cinergy | $48.47 | $44.00 | $53.00 | 6,550 | 104,800 | 131 |
| North ECAR | $51.52 | $45.00 | $55.00 | 1,405 | 22,480 | 28 |
| PJM-West | $49.01 | $46.00 | $54.00 | 2,800 | 44,800 | 56 |
| Nepool | $74.00 | $72.00 | $80.00 | 500 | 8,000 | 10 |
| NY Zone G | $67.50 | $67.50 | $67.50 | 200 | 3,200 | 4 |
| NY Zone A | $57.85 | $57.00 | $59.00 | 600 | 9,600 | 12 |
| NY Zone J | $81.00 | $81.00 | $81.00 | 50 | 800 | 1 |
| VaCar | $46.00 | $46.00 | $46.00 | 150 | 2,400 | 3 |
| Southern | $45.00 | $45.00 | $45.00 | 50 | 800 | 1 |
| TVA, into | $43.92 | $43.00 | $47.00 | 1,200 | 19,200 | 24 |
| Fla.-Ga. | $42.50 | $40.00 | $45.00 | 100 | 1,600 | 2 |
| Fla. in-state | — | — | — | 0 | 0 | 0 |

## Trades for Standard Forward Products *(all prices in $/MWh)*

| Delivery Point | Next Week 12/18 to 12/22 Low | Next Week High | Balance of Month 12/12 to 12/31 Low | Balance of Month High | Prompt Month 01/01 Low | Prompt Month High | Index | All pk. hrs. vol. | No. of Trades |
|---|---|---|---|---|---|---|---|---|---|
| **West** | | | | | | | | | |
| COB | — | — | — | — | — | — | — | 0 | 0 |
| Mid-Columbia | — | — | — | 2,000.00 | 575.00 | 800.00 | 675.00 | 1,200 | 3 |
| NP15 | — | — | — | — | — | 320.00 | 320.00 | 400 | 1 |
| Palo Verde | — | — | — | — | 250.00 | 375.00 | 300.00 | 1,200 | 3 |
| SP15 | — | — | — | — | — | — | — | 0 | 0 |
| **Central** | | | | | | | | | |
| Com Ed, into | — | 75.00 | — | 68.00 | — | — | — | 0 | 0 |
| Entergy, into | — | — | — | — | — | — | — | 0 | 0 |
| **East** | | | | | | | | | |
| Cinergy, into | 72.00 | 85.00 | — | 70.00 | — | — | — | 0 | 0 |
| PJM-West | — | — | — | 61.00 | — | — | — | 0 | 0 |
| NEPOOL | 82.00 | 90.00 | 82.00 | 85.00 | — | — | — | 0 | 0 |
| NY Zone G | — | — | — | — | — | — | — | 0 | 0 |
| NY Zone A | 60.00 | 60.50 | — | — | — | — | — | 0 | 0 |
| NY Zone J | — | — | — | — | — | — | — | 0 | 0 |
| TVA, into | — | 66.00 | — | — | — | — | — | 0 | 0 |

## Ranges and Indexes of Trades for Standard Off-Peak Products

Delivery Date: 12/11/00

| | Wtd. Av. Index | Absolute Low | Absolute High | Trading Vol. Reported |
|---|---|---|---|---|
| **West** | | | | |
| COB | — | — | — | 0 |
| Four C | $275.00 | $275.00 | $275.00 | 25 |
| Mead, Nev. | — | — | — | 0 |
| Mid-C | $2,016.67 | $1,550.00 | $2,500.00 | 75 |
| NP15 | — | — | — | 0 |
| Palo Verde | $275.00 | $275.00 | $275.00 | 25 |
| SP15 | — | — | — | 0 |
| **Central** | | | | |
| ERCOT-B | — | — | — | 0 |
| Ameren | — | — | — | 0 |
| Com Ed, into | $19.00 | $19.00 | $19.00 | 300 |
| MAIN North | — | — | — | 0 |
| MAIN South | — | — | — | 0 |
| MAPP North | $21.00 | $21.00 | $21.00 | 125 |
| MAPP South | $20.00 | $20.00 | $20.00 | 100 |
| Entergy, into | — | — | — | 0 |
| SPP | $17.04 | $13.00 | $23.50 | 260 |
| **East** | | | | |
| Cinergy | — | — | — | 0 |
| North ECAR | $19.50 | $19.00 | $19.55 | 1,157 |
| PJM-West | — | — | — | 0 |
| Nepool | — | — | — | 0 |
| NY Zone G | — | — | — | 0 |
| NY Zone A | — | — | — | 0 |
| NY Zone J | — | — | — | 0 |
| VaCar | — | — | — | 0 |
| Southern | — | — | — | 0 |
| TVA, into | — | — | — | 0 |
| Fla.-Ga. | $25.00 | $25.00 | $25.00 | 50 |
| Fla. in-state | — | — | — | 0 |

## MGE, Alliant propose plant for university

A proposal between Madison Gas & Electric (MGE), Alliant Energy, the University of Wisconsin-Madison and Wisconsin's Department of Administration may result in a $170 million, 90- to 100-MW, natural gas-fired power plant on school ground that could solve a long-term energy crunch facing both the university and the city, the parties said last week.

If the plant gets all approvals necessary, the two utilities will jointly plan and oversee construction of the facility, which is anticipated to start in summer 2002. Plant operation is expected to begin in late 2003 or spring 2004.

Once construction is complete, MGE would own the facility with a third-party investor but would retain full operational control. Alliant will act as project manager. Although not a specified owner, Alliant will be paid for its services, company representative Chris Schoenherr said.

The proposed site at the university has the necessary infrastructure in place to support the facility, including electric transmission lines, a power substation and natural gas lines. MCM

## Dailies scream to $5,000 at Mid-C, $3,000 at COB

**Western Markets**

The relentless upswing in next-day prices prevailed, with dailies trading to $5,000 at Mid-Columbia and $3,000 at COB.

"This is history," one source said. "Someone who buys power at that price [$5,000] is walking wounded. Actually, they're not even walking."

Overall, next-day volume was sparse. Deals arranged for today's delivery traded up to $425 at Palo Verde and near $350 at SP15.

In the bilateral market, off-peak for today traded near $275 at Palo Verde and at Four Corners.

The extreme pressure on prices carried over into the term markets, where balance-of-the-month sold for $2,000 at Mid-C and January there sold for $800 for a third consecutive day.

Crippled by idled power plants and tight energy imports, the state's power grid strained to meet the load going into the weekend. The danger of blackouts, caused by cold weather and an unprecedented drop in the energy supply, was expected to grow severely today, as an Arctic front blows down the West Coast from Canada.

Going into the weekend, California Power Exchange prices for Saturday peak were $251.23, with off-peak $256.79 and the 24-hour weighted average at $252.79. A day earlier, prices were fractions of a cent above $250.

The Bonneville Power Administration had no surplus power to sell at least through Saturday.

Friday began with a Stage 2 declaration by the California Independent System Operator — the fifth such declaration in as many days and the ninth in three weeks.

Also firming up power prices was the cost of natural gas, which reached as high as $63 at COB/Malin, Ore., $61 at the Pacific Gas & Electric Citygate and $55 at the Southern California Border.

At Palo Verde, January ranged $250-$375 and near $320 at NP15.

Second-quarter 2001 traded as high as $215 at Mid-C and in a tight range to $190 at Palo Verde.

Third-quarter 2001 sold at or above $290 at Palo Verde. KW/NM

## Transmission problems force Entergy to mid $70s

**Central Markets**

Entergy dailies opened at $50, about $23 lower than the previous day's trades. However, they soon regained ground, passing the high from the day before.

By the end of the day deals were done at $76, a net gain of $1. Traders were not certain what was driving prices up, but suspected transmission constraints.

In MAIN, ComEd dailies fell even further, about $16 to the low $50s. Off-peak sold near $19.

Weekend trades moved in the low $30s and off-peak sold in the low $20s.

After undergoing a hot shutdown last week, ComEd's 828-MW nuke unit, Quad Cities 1, began powering back up after repairs.

Northern MAIN dailies moved around the low $60s. However, the same unfortunate player who all last week caught the high deals paid around $120 for a much-needed package. Weekend peak sold in the upper $20s.

Ameren reported weekend off-peak deals near $20.

Light weekend demand helped push northern MAPP dailies down about $20, to $75.

### Central Generation Outage Report for December 11

Information from the Nuclear Regulatory Commission is sometimes outdated, and not all utilities respond to requests for verification of unit status. Copyright 2000 by FT Energy

| Unit Name, Operator | MW | NERC Region | Unit Status | Scheduled restart or outage date |
|---|---|---|---|---|
| LaSalle 2 ComEd | 828 | MAIN | Nuclear; operating at 100% following Oct. 6 refueling outage | Full power Dec. 8 |
| Quad Cities 1 ComEd | 828 | MAIN | Nuclear; operating at 1% after hot shutdown Dec. 6 | Start up on Dec. 7 |

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-18)

## Avista Corporation
# 2001 Load and Estimated Variability

| | Avg (aMW) | Jan (aMW) | Feb (aMW) | Mar (aMW) | Apr (aMW) | May (aMW) | Jun (aMW) | Jul (aMW) | Aug (aMW) | Sep (aMW) | Oct (aMW) | Nov (aMW) | Dec (aMW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Average Load [1] | 965.1 | 1,147.0 | 1,108.9 | 975.4 | 906.6 | 861.9 | 867.7 | 911.1 | 956.5 | 864.0 | 910.4 | 1,001.0 | 1,078.0 |
| 80% CI [2] | 43.5 | 86.9 | 67.6 | 40.4 | 36.1 | 12.3 | 35.5 | 39.0 | 45.7 | 20.6 | 33.2 | 49.0 | 56.5 |
| 95% CI [2] | 67.3 | 134.5 | 104.7 | 62.5 | 55.8 | 19.0 | 54.9 | 60.4 | 70.8 | 31.9 | 51.5 | 75.8 | 87.4 |

(1) Jan-Oct actuals including full Potlatch load, Nov-Dec values are estimated with 93 aMW of Potlatch lad

(2) average of weekly weekly confidence interval values

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-C19)

CONFIDENTIAL

AVISTA® Corporation

Energy Resources

**Kettle Fall – "Bi-Fuel" (Nat. Gas/Oil) Generation**
April 7, 2001

**Situation**
Although the company has worked hard to balance the utility's load and resource positions, there are conditions that require additional short-term supplies of power. It is prudent for us to protect ourselves from short-term deficiencies, variability in available power from hydro projects, variability in loads and generation unit outage risk given the high prices and volatility evident in the competitive electric power market. Building additional generation suitable for economic short-term supply is one such way to obtain that protection.

**Kettle Falls "Bi-Fuel" Generation**
We have received a proposal for 10.8 megawatts of generation that would be located at the Kettle Falls Generating Station. The generation package consists of "bi-fuel" (simultaneous natural gas and oil operation) reciprocating engine generators. This bi-fuel generation is particularly suited to the Kettle Falls location. Natural gas may not be available during all time periods on the Kettle Falls gas lateral. This type of reciprocating generation unit will shift from 80%/20% gas/oil operation to 100% oil operation under conditions when gas is not available. 100% oil operation could occur up to 4 months per year. This is the scenario used in our economic analysis.

These are new units that are assembled in Canada. The project consists of six 1.8MW units. Half of the units could be delivered as early as mid-April with the other half in mid-May. Units are in weatherproof enclosures and would have additional sound abatement material installed. They can be placed on crushed gravel without a foundation. The units are relatively efficient with a 9615 heat rate on 80%/20% gas/oil operation. Because of uncertainty around air permit limitations, either a 12-month lease or purchase are the financial options considered. The equipment has a 10% residual value at the end of the 12-month lease.

There are several scenarios under which these units might operate depending on the air permit process:

1. Operate 7/1/01 until whatever time the new 7MW CT begins operation at Kettle Falls (approximately 1/14/02) under a 12 month emergency temporary permit. This assumes that air permit studies show that we cannot operate the existing plant, the new 7MW CT and these 10.8MW bi-fuel generation units simultaneously and units cannot be moved to another site. Under this scenario, the 10.8MW units would be shut-down on 1/14/01.
2. Operate 7/1/01 until whatever time the new 7MW CT begins operation at Kettle Falls. When the new 7MW CT begins operation, move the 10.8MW bi-fuel generation to a location (tentatively we have identified Hallet & White substation) in Spokane County where emergency temporary permits can be obtained for limited 6 month periods. Operate through 6/30/02 at the second location.
3. Begin operation at Kettle Falls 7/1/01 under the emergency temporary permit. If air quality modeling for the new 7MW CT indicates that the existing plant, 7MW CT, and the 10.8MW

bi-fuel generation can all be operated simultaneously, then a permanent permit application will be filed such that the 10.8MW bi-fuel units can operate indefinately. In this scenario, the bi-fuel units will be left at Kettle Falls through 6/30/02.

Scenario #3 is the best case. Scenario #1 is the worst case. We have financially modeled both cases.

Issues associated with this generation include:

- **Air Permit** – These units would operate on a temporary (12-month) "emergency generation" permit basis up until the time when the new 7MW CT (which has already approved for Kettle Falls) will come on line (approximate on-line date 1/15/02). We expect a 30 day permit time-line under the governor's program. We will proceed with permitting the 7MW unit after we receive the emergency temporary permit for the 10.8MW generation. We will include in that modeling analysis one scenario where the existing generation plant, the 7MW turbine, as well as the 10.8 MW bi-fuel generation operate simultaneously. We will then evaluate whether it is reasonable to request a permanent permit for all three generation projects, or whether we will stop generation of the bi-fuel units at the Kettle Falls site at the time the 7MW CT comes on line. These units will have SCR emission control equipment added to control NOx and CO.

  [We are in the process of obtaining the air permit modeling for this project. Results are expected within the next week.]

- **Property** – All units will fit on the existing Kettle Falls site. Noise abatement measures are planned due to residences nearby.

- **Building Permit** – This generation comes in unit containers and will set directly on crushed gravel. We plan to build an additional 15,000 gallon oil storage tank to supplement the existing 10,000 gallon tank on site.

- **Electrical Interconnection** – Generation will come with transformers to step-up to 13.8KV and it is planned to integrate them into the distribution system at that voltage.

  [Engineering must give the final ok on the number of units at this site depending on some specific electrical parameters that relate to fault duty.]

- **Gas Supply** – There is natural gas available at Kettle Falls. A new gas regulator and additional gas lines are budgeted. As discussed above, capacity for natural gas may not be available on all days depending on downstream use (including NW Alloys use) as well as Kettle Falls plant use to augment wood fuel and the new 7MW CT natural gas useage.

- **Oil Storage** – As described above, we plan to have 25,000 gallons of storage capacity on-site. Additionally, each generation unit comes equipped with a 2400 gallon double wall tank. Therefore, we will have a total of 39,400 gallons of oil storage capability at Kettle Falls. This capacity provides for approximately 10 days of operation on 80%/20% gas/oil operation and 2 days of operation on 100% oil operation.

- **Financing** – These units could be either purchased or financed through a lease with US Bancorp. The equipment has a 10% residual value at the end of the lease and we would have an option to purchase the equipment at that value. [We received the form of the lease agreement on 3/23 and it has not been reviewed.]

- **Reliability** – Due to the small unit configuration, the company benefits from the diversification.

- **Economics** – The planned operation of these units is to provide a lower cost alternative, compared to purchasing firm power in the market to cover short-term deficiencies, variability in available power ~~form~~ from hydro projects, variability in loads and generation unit outage risk Doing so would reduce the electric deferral balance.

  The following information is based on the currrent forward market prices for both natural gas and electricity. Two scenarios have been prepared for the analysis. Scenario 1 assumes the generation is operational for 12 month period. Scenario 2 assumes the generation is operational for a 6 month period (although the lease payments continue for the full 12 months). Results of the analysis are as follows:

| | Scenario 1 12 Month Operation (85,147 MWh) | | Scenario 2 6 Month Operation (42,924 MWh) | |
|---|---|---|---|---|
| | $/MWh | Total Dollars | $/MWh | Total Dollars |
| Fixed Cost To Generate | $53 | $4.5 million | $105 | $4.5 million |
| Variable Cost To Generate | $86 | $7.3 million | $88 | $3.8 million |
| Total Cost To Generate | $139 | $10.9 million | $192 | $8.3 million |
| Ave. Flat Forward Market | $265 | $21.7 million | $358 | $15.4 million |
| Project Benefit | $127 | $10.8 million | $166 | $7.1 million |

This economic analysis assumes a July 1st on-line date. It is likely that this generation can be put on line more quickly.

A revenue requirement analysis has also been performed showing a comparison of a 12 month operation under a 12 month lease arrangement and a purchase option that allows the units to operate over a 25 year life. The 12 month lease option shows a $11.9 million positive benefit while the purchase option shows a $11.3 million positive benefit.

The purchase option has greater benefits in year one and two when the spark spread between electricity and natural gas creates high positive benefits. Thereafter, the spark spread is not great enough to overcome the ongoing fixed costs of the project, even though it operates on a variable cost basis.

Comparatively, the lease option has less value in the first two years. However, this is probably a better match of the costs to the benefits of this project. The lease places most of the costs into the 12-month lease (which straddles a two year time period in the analysis). This is also when the greatest benefits to customers occur.

Cost of the 12 month lease including emission equipment is $348,641/month. Additional sound abatement costs may be added to this.

Cost of the generation equipment including emission equipment is $4,402,588 not including tax. Cost to purchase the generation equipment plus tax, installation, and sound abatement is estimated at $5,054,000

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**Cash Flow Analysis**

**10.8MW Bi-Fuel Reciprocating Generation**

**1 Year Lease with No Purchase At Termination - 12 Month Operation**

Capacity 10.8

Heat Rate 9616 (80% gas/20% Oil)

| | Totals | Mar-01 | Apr-01 | May-01 | Jun-01 | Jul-01 | Aug-01 | Sep-01 | Oct-01 | Nov-01 | Dec-01 | Jan-02 | Feb-02 | Mar-02 | Apr-02 | May-02 | Jun-02 | Jul-02 | Aug-02 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hours in Month | 46,728 | 744 | 720 | 744 | 720 | 744 | 744 | 720 | 744 | 720 | 744 | 744 | 672 | 744 | 720 | 744 | 720 | 744 | 744 |
| Lease Payments | 4,183,691 | | | | | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ - | $ - |
| Pre-Lease Payments | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Other Fixed Costs | 310,000 | $ - | $ 125,000 | $ 185,000 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Fuel Costs | 5,854,662 | $ - | $ - | $ - | $ - | $ 479,494 | $ 481,232 | $ 464,026 | $ 509,051 | $ 537,624 | $ 555,545 | $ 555,545 | $ 501,782 | $ 516,005 | $ 416,915 | $ 425,016 | $ 412,428 | $ - | $ - |
| Variable O&M (Estimate $17/MWh) | 1,447,502 | | | | | $ 122,939 | $ 122,939 | $ 118,973 | $ 122,939 | $ 118,973 | $ 122,939 | $ 122,939 | $ 111,041 | $ 122,939 | $ 118,973 | $ 122,939 | $ 118,973 | $ - | $ - |
| Total Costs (Cash Flow) | 11,795,856 | $ - | $ 125,000 | $ 185,000 | $ - | $ 951,073 | $ 952,812 | $ 931,640 | $ 980,630 | $ 1,005,238 | $ 1,027,124 | $ 1,027,124 | $ 961,465 | $ 987,585 | $ 884,528 | $ 896,596 | $ 880,041 | $ - | $ - |
| NPV @ 9.25% | 10,909,686 | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| Total Generation MWh @ 90% LF | 85,147 | | | | | 7,232 | 7,232 | 6,998 | 7,232 | 6,998 | 7,232 | 7,232 | 6,532 | 7,232 | 6,998 | 7,232 | 6,998 | - | - |
| Total Costs/MWh @ 90% LF | | | | | | $ 131.51 | $ 131.76 | $ 133.12 | $ 135.60 | $ 143.64 | $ 142.03 | $ 142.03 | $ 147.20 | $ 136.56 | $ 126.39 | $ 123.98 | 125.75 | #DIV/0! | #DIV/0! |
| | | | | | | | | | | | | | | | | | | | |
| Scenario 1: Operate for 12 Months | | | | | | | | | | | | | | | | | | | |
| Average Fixed Costs $/MWh | $ 53 | | | | | | | | | | | | | | | | | | |
| Average Variable Costs $/MWh | $ 86 | | | | | | | | | | | | | | | | | | |
| Average Total Costs $/MWh | $ 139 | | | | | | | | | | | | | | | | | | |
| Average Flat Forward Market $/MWh | $ 265 | | | | | $ 388.00 | $ 422.00 | $ 391.00 | $ 322.00 | $ 284.00 | $ 291.00 | $ 252.00 | $ 225.00 | $ 198.00 | $ 134.00 | $ 129.00 | $ 139.00 | $ 194.00 | $ 190.00 |
| Project Benefit - $/MWh | $ 127 | | | | | $ 256.49 | $ 290.24 | $ 257.88 | $ 186.40 | $ 140.36 | $ 148.97 | $ 109.97 | $ 77.80 | $ 61.44 | $ 7.61 | $ 5.02 | 13.25 | #DIV/0! | #DIV/0! |
| Project Benefit - Total Dollars | $ 10,786,114 | $ - | $ (125,000) | $ (185,000) | $ - | 1,854,819 | 2,098,957 | 1,804,735 | 1,347,971 | 982,308 | 1,077,295 | 795,259 | 508,199 | 444,288 | 53,257 | 36,291 | 92,736 | #DIV/0! | #DIV/0! |
| **Support** | | | | | | | | | | | | | | | | | | | |
| **Pre-Lease Costs** | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | | | | | | | | | | | |
| **Other Fixed Costs** | 310,000 | $ - | $ 125,000 | $ 185,000 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Property Acquisition | | | $ - | | | | | | | | | | | | | | | | |
| Air Permitting Costs | | | $ 10,000 | $ 10,000 | | | | | | | | | | | | | | | |
| Building Costs (Building and Pads) | | | $ - | $ 15,000 | | | | | | | | | | | | | | | |
| Building Permit Costs | | | $ 5,000 | | | | | | | | | | | | | | | | |
| Gas Regulator Installation | | | $ - | $ 85,000 | | | | | | | | | | | | | | | |
| Substation Extension | | | $ 75,000 | $ 75,000 | | | | | | | | | | | | | | | |
| Oil Tank | | | $ 35,000 | | | | | | | | | | | | | | | | |
| **Nat Gas Costs** | | | | | | | | | | | | | | | | | | | |
| MMBtu Consumed/Month | | | | | | 57,955 | 57,955 | 56,085 | 57,955 | - | - | - | - | 57,955 | 56,085 | 57,955 | 56,085 | - | - |
| Cost of Delivered Gas/MMBtu | | | | | | $ 6.14 | $ 6.17 | $ 6.14 | $ 6.65 | $ 7.18 | $ 7.29 | $ 7.31 | $ 7.10 | $ 6.77 | $ 5.30 | $ 5.20 | $ 5.22 | $ 5.27 | $ 5.28 |
| Avista Gas Transportation ($/dth) | | | | | | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | 0.21 | | |
| Total Gas Cost/Month | $ 2,822,696 | | | | | $ 367,961 | $ 369,699 | $ 356,091 | $ 397,518 | $ - | $ - | $ - | $ - | $ 404,472 | $ 308,979 | $ 313,483 | $ 304,493 | $ - | $ - |
| **Oil Costs** | | | | | | | | | | | | | | | | | | | |
| Gallons Consumed/Month | | | | | | 111,533 | 111,533 | 107,935 | 111,533 | 537,624 | 555,545 | 555,545 | 501,782 | 111,533 | 107,935 | 111,533 | 107,935 | | |
| Cost of Oil/Gallon | | | | | | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | 1.00 | | |
| Cost of Oil/MMBTU | | | | | | $ 7.69 | $ 7.69 | $ 7.69 | $ 7.69 | $ 7.69 | $ 7.69 | $ 7.69 | $ 7.22 | $ 7.22 | $ 7.22 | $ 7.22 | 7.22 | | |
| Total Oil Cost/Month | $ 3,031,967 | | | | | $ 111,533 | $ 111,533 | $ 107,935 | $ 111,533 | $ 537,624 | $ 555,545 | $ 555,545 | $ 501,782 | $ 111,533 | $ 107,935 | $ 111,533 | 107,935 | | |
| | | | | | | | | | | | | | | | | | | | |
| **Total Fuel Cost/Month** | | | | | | $ 479,494 | $ 481,232 | $ 464,026 | $ 509,051 | $ 537,624 | $ 555,545 | $ 555,545 | $ 501,782 | $ 516,005 | $ 416,915 | $ 425,016 | 412,428 | | |

04-09-2001 12:32 PM

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**Cash Flow Analysis**
**10.8MW Bi-Fuel Reciprocating Generation**
**1 Year Lease with No Purchase At Termination - 6 Month Operation**

Capacity 10.8
Heat Rate 9616 (80% gas/20% Oil)

| | Totals | Mar-01 | Apr-01 | May-01 | Jun-01 | Jul-01 | Aug-01 | Sep-01 | Oct-01 | Nov-01 | Dec-01 | Jan-02 | Feb-02 | Mar-02 | Apr-02 | May-02 | Jun-02 | Jul-02 | Aug-02 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hours in Month | 46,728 | 744 | 720 | 744 | 720 | 744 | 744 | 720 | 744 | 720 | 744 | 744 | 672 | 744 | 720 | 744 | 720 | 744 | 744 |
| Lease Payments | 4,183,691 | | | | | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ - | $ - |
| Pre-Lease Payments | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Other Fixed Costs | 310,000 | $ - | $ 125,000 | $ 185,000 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Fuel Costs | 3,026,972 | $ - | $ - | $ - | $ - | $ 479,494 | $ 481,232 | $ 464,026 | $ 509,051 | $ 537,624 | $ 555,545 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Variable O&M (Estimate $17/MWh) | 729,700 | | | | | $ 122,939 | $ 122,939 | $ 118,973 | $ 122,939 | $ 118,973 | $ 122,939 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Total Costs (Cash Flow) | 8,250,363 | $ - | $ 125,000 | $ 185,000 | $ - | $ 951,073 | $ 952,812 | $ 931,640 | $ 980,630 | $ 1,005,238 | $ 1,027,124 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ 348,641 | $ - | $ - |
| Total Generation MWh @ 90% LF | 42,924 | | | | | 7,232 | 7,232 | 6,998 | 7,232 | 6,998 | 7,232 | - | - | - | - | - | - | - | - |
| Total Costs/MWh @ 90% LF | | | | | | $ 131.51 | $ 131.76 | $ 133.12 | $ 135.60 | $ 143.64 | $ 142.03 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| Scenario 1 - Operate for 6 Months | | | | | | | | | | | | | | | | | | | |
| Average Fixed Costs $/MWh | $ 105 | | | | | | | | | | | | | | | | | | |
| Average Variable Costs $/MWh | $ 88 | | | | | | | | | | | | | | | | | | |
| Average Total Costs $/MWh | $ 192 | | | | | | | | | | | | | | | | | | |
| Average Flat Forward Market $/MWh | $ 358 | | | | | $ 388.00 | $ 422.00 | $ 391.00 | $ 322.00 | $ 284.00 | $ 291.00 | $ 252.00 | $ 225.00 | $ 198.00 | $ 134.00 | $ 129.00 | $ 139.00 | $ 194.00 | $ 190.00 |
| Project Benefit - $/MWh | $ 166 | | | | | $ 256.49 | $ 290.24 | $ 257.88 | $ 186.40 | $ 140.36 | $ 148.97 | | | | | | | #DIV/0! | #DIV/0! |
| Project Benefit - Total Dollars | $ 7,112,879 | $ - | $ (125,000) | $ (185,000) | $ - | 1,854,819 | 2,098,957 | 1,804,735 | 1,347,971 | 982,308 | 1,077,295 | (348,641) | (348,641) | (348,641) | (348,641) | (348,641) | - | #DIV/0! | #DIV/0! |
| NPV @ 9.25% | 6,800,159 | | | | | | | | | | | | | | | | | | |

**Support**

| | Totals | Mar-01 | Apr-01 | May-01 | Jun-01 | Jul-01 | Aug-01 | Sep-01 | Oct-01 | Nov-01 | Dec-01 | Jan-02 | Feb-02 | Mar-02 | Apr-02 | May-02 | Jun-02 | Jul-02 | Aug-02 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Pre-Lease Costs** | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Other Fixed Costs** | 310,000 | $ - | $ 125,000 | $ 185,000 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Property Acquisition | | | $ - | | | | | | | | | | | | | | | | |
| Air Permitting Costs | | | $ 10,000 | $ 10,000 | | | | | | | | | | | | | | | |
| Building Costs (Building and Pads) | | | $ - | $ 15,000 | | | | | | | | | | | | | | | |
| Building Permit Costs | | | $ 5,000 | | | | | | | | | | | | | | | | |
| Gas Regulator Installation | | | $ - | $ 85,000 | | | | | | | | | | | | | | | |
| Substation Extension | | | $ 75,000 | $ 75,000 | | | | | | | | | | | | | | | |
| Oil Tank | | | $ 35,000 | | | | | | | | | | | | | | | | |
| **Nat Gas Costs** | | | | | | | | | | | | | | | | | | | |
| MMBtu Consumed/Month | | | | | | 57,955 | 57,955 | 56,085 | 57,955 | - | - | - | - | - | - | - | - | - | - |
| Cost of Delivered Gas/MMBtu | | | | | | $ 6.14 | $ 6.17 | $ 6.14 | $ 6.65 | $ 7.18 | $ 7.29 | $ 7.31 | $ 7.10 | $ 6.77 | $ 5.30 | $ 5.20 | $ 5.22 | $ 5.27 | $ 5.28 |
| Avista Gas Transportation ($/dth) | | | | | | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | $ 0.21 | | | | | | | | |
| Total Gas Cost/Month | $ 1,491,268 | | | | | $ 367,961 | $ 369,699 | $ 356,091 | $ 397,518 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Oil Costs** | | | | | | | | | | | | | | | | | | | |
| Gallons Consumed/Month | | | | | | 111,533 | 111,533 | 107,935 | 111,533 | 537,624 | 555,545 | - | - | - | - | - | - | | |
| Cost of Oil/Gallon | | | | | | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | | |
| Cost of Oil/MMBTU | | | | | | $ 7.69 | $ 7.69 | $ 7.69 | $ 7.69 | $ 7.69 | $ 7.69 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | | |
| Total Oil Cost/Month | $ 1,535,703 | | | | | $ 111,533 | $ 111,533 | $ 107,935 | $ 111,533 | $ 537,624 | $ 555,545 | $ - | $ - | $ - | $ - | $ - | $ - | | |
| **Total Fuel Cost/Month** | | | | | | $ 479,494 | $ 481,232 | $ 464,026 | $ 509,051 | $ 537,624 | $ 555,545 | $ - | $ - | $ - | $ - | $ - | $ - | | |

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# 10.8 MW Bi-Fuel Fired Recips -- Online July 2001 -- Purchase Option

## Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | |
|---|---|---|
| Installed Cost | 5,054 | $000s |
| Project Capacity | 10.8 | MW |
| Heat Rate | 9,615 | Btu/kWh |
| Peak Gas Useage | 2,492 | 000s dth |
| Fixed Charge | 0.00 | per kW-month |
| Fixed O&M | 0.45 | 2003$ per kW-month |
| Escalation Rates | | |
| Fixed O&M | 2.5 | percent |
| Variable O&M | 2.5 | percent |
| Transportation | 2.5 | percent |
| Variable O&M | 10.00 | 2001$/MWh |
| Insurance Cost | 15.16 | 0.3% of installed cost ($000s) |
| Gas Transport | 0.00 | 2000 $/dth |
| Electric Wheeling | 0 | $/MW-month thru 2006 |
| General Inflation | 2.5 | percent |
| Electric Wheeling Losses | 0.0 | percent |
| Nominal Discount Rate | 7.77 | percent |
| Real Discount Rate | 5.1 | percent |
| IRR | | |
| Profitability Index | 2.24 | |

**Fixed Costs**

| Row | | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 1 | 2001 | 45.3 | 979 | 0 | 979 | 21.6 | 56 | 0 | 0 | 69 | 15 | 140 | 3.1 |
| 19 | 2 | 2002 | 89.9 | 963 | 0 | 963 | 10.7 | 57 | 0 | 0 | 67 | 16 | 139 | 1.5 |
| 20 | 3 | 2003 | 67.2 | 942 | 0 | 942 | 14.0 | 58 | 0 | 0 | 64 | 16 | 138 | 2.1 |
| 21 | 4 | 2004 | 22.4 | 790 | 0 | 790 | 35.2 | 60 | 0 | 0 | 62 | 16 | 138 | 6.2 |
| 22 | 5 | 2005 | 7.6 | 720 | 0 | 720 | 94.3 | 61 | 0 | 0 | 59 | 17 | 137 | 18.0 |
| 23 | 6 | 2006 | 0.0 | 672 | 0 | 672 | #DIV/0! | 63 | 0 | 0 | 57 | 17 | 137 | #DIV/0! |
| 24 | 7 | 2007 | 0.0 | 647 | 0 | 647 | #DIV/0! | 64 | 0 | 0 | 55 | 18 | 137 | #DIV/0! |
| 25 | 8 | 2008 | 15.3 | 660 | 0 | 660 | 43.3 | 66 | 0 | 0 | 52 | 18 | 136 | 8.9 |
| 26 | 9 | 2009 | 15.3 | 629 | 0 | 629 | 41.2 | 68 | 0 | 0 | 50 | 18 | 136 | 8.9 |
| 27 | 10 | 2010 | 15.3 | 606 | 0 | 606 | 39.7 | 69 | 0 | 0 | 48 | 19 | 136 | 8.9 |
| 28 | 11 | 2011 | 15.3 | 583 | 0 | 583 | 38.2 | 71 | 0 | 0 | 45 | 19 | 136 | 8.9 |
| 29 | 12 | 2012 | 15.3 | 561 | 0 | 561 | 36.7 | 73 | 0 | 0 | 43 | 20 | 136 | 8.9 |
| 30 | 13 | 2013 | 15.3 | 538 | 0 | 538 | 35.2 | 75 | 0 | 0 | 40 | 20 | 135 | 8.9 |
| 31 | 14 | 2014 | 15.3 | 515 | 0 | 515 | 33.7 | 77 | 0 | 0 | 38 | 21 | 135 | 8.9 |
| 32 | 15 | 2015 | 15.3 | 493 | 0 | 493 | 32.3 | 78 | 0 | 0 | 36 | 21 | 135 | 8.9 |
| 33 | 16 | 2016 | 15.3 | 470 | 0 | 470 | 30.8 | 80 | 0 | 0 | 33 | 22 | 136 | 8.9 |
| 34 | 17 | 2017 | 15.3 | 448 | 0 | 448 | 29.3 | 82 | 0 | 0 | 31 | 23 | 136 | 8.9 |
| 35 | 18 | 2018 | 15.3 | 425 | 0 | 425 | 27.8 | 84 | 0 | 0 | 29 | 23 | 136 | 8.9 |
| 36 | 19 | 2019 | 15.3 | 404 | 0 | 404 | 26.4 | 87 | 0 | 0 | 26 | 24 | 136 | 8.9 |
| 37 | 20 | 2020 | 15.3 | 382 | 0 | 382 | 25.0 | 89 | 0 | 0 | 24 | 24 | 137 | 9.0 |
| 38 | 21 | 2021 | 15.3 | 364 | 0 | 364 | 23.8 | 91 | 0 | 0 | 21 | 25 | 137 | 9.0 |
| 39 | 22 | 2022 | 15.3 | 350 | 0 | 350 | 22.9 | 93 | 0 | 0 | 19 | 25 | 138 | 9.0 |
| 40 | 23 | 2023 | 15.3 | 339 | 0 | 339 | 22.2 | 96 | 0 | 0 | 17 | 26 | 138 | 9.1 |
| 41 | 24 | 2024 | 15.3 | 325 | 0 | 325 | 21.3 | 49 | 0 | 0 | 14 | 27 | 90 | 5.9 |
| 42 | 25 | 2025 | 15.3 | 314 | 0 | 314 | 20.6 | 50 | 0 | 0 | 12 | 27 | 90 | 5.9 |
| 44 | 2001$ | | | | | | | | | | | | | |
| 45 | Net Present Value | | | 7,249 | 0 | 7,249 | | 737 | 0 | 0 | 535 | 206 | 1,477 | |
| 46 | Nominal Levelized Cost ($/MWh) | | | | | | 32.8 | | | | | | | 6.7 |
| 47 | Real Levelized Cost ($/MWh) | | | | | | 25.7 | | | | | | | 5.2 |

| Row | Year | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 2001 | 1,119 | 1,119 | 24.7 | 12,437 | 11,318 | 249.8 | 3,120 | 453 | 3,573 | 78.9 | 4,692 | 103.6 |
| 19 | 2002 | 1,102 | 1,102 | 12.3 | 7,865 | 6,763 | 75.2 | 2,866 | 899 | 3,765 | 41.9 | 4,867 | 54.1 |
| 20 | 2003 | 1,081 | 1,081 | 16.1 | 955 | (125) | (1.9) | 3,278 | 672 | 3,951 | 58.8 | 5,031 | 74.8 |
| 21 | 2004 | 927 | 927 | 41.4 | 267 | (660) | (29.5) | 1,126 | 224 | 1,350 | 60.2 | 2,277 | 101.6 |
| 22 | 2005 | 857 | 857 | 112.3 | 53 | (804) | (105.4) | 379 | 76 | 455 | 59.6 | 1,312 | 171.9 |
| 23 | 2006 | 809 | 809 | #DIV/0! | 0 | (809) | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 809 | #DIV/0! |
| 24 | 2007 | 783 | 783 | #DIV/0! | 0 | (783) | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 783 | #DIV/0! |
| 25 | 2008 | 797 | 797 | 52.2 | 83 | (713) | (46.7) | 639 | 153 | 792 | 51.9 | 1,588 | 104.0 |
| 26 | 2009 | 765 | 765 | 50.1 | 117 | (648) | (42.4) | 482 | 153 | 635 | 41.6 | 1,400 | 91.7 |
| 27 | 2010 | 742 | 742 | 48.6 | 102 | (640) | (41.9) | 498 | 153 | 651 | 42.6 | 1,393 | 91.2 |
| 28 | 2011 | 719 | 719 | 47.1 | 106 | (613) | (40.1) | 516 | 153 | 668 | 43.8 | 1,387 | 90.9 |
| 29 | 2012 | 696 | 696 | 45.6 | 250 | (446) | (29.2) | 535 | 153 | 687 | 45.0 | 1,383 | 90.6 |
| 30 | 2013 | 673 | 673 | 44.1 | 96 | (577) | (37.8) | 554 | 153 | 707 | 46.3 | 1,380 | 90.4 |
| 31 | 2014 | 651 | 651 | 42.6 | 122 | (529) | (34.6) | 576 | 153 | 728 | 47.7 | 1,379 | 90.3 |
| 32 | 2015 | 628 | 628 | 41.1 | 121 | (507) | (33.2) | 601 | 153 | 754 | 49.4 | 1,382 | 90.5 |
| 33 | 2016 | 606 | 606 | 39.7 | 119 | (486) | (31.9) | 626 | 153 | 779 | 51.0 | 1,384 | 90.7 |
| 34 | 2017 | 583 | 583 | 38.2 | 125 | (459) | (30.1) | 651 | 153 | 804 | 52.7 | 1,387 | 90.9 |
| 35 | 2018 | 561 | 561 | 36.7 | 152 | (409) | (26.8) | 674 | 153 | 826 | 54.1 | 1,387 | 90.9 |
| 36 | 2019 | 540 | 540 | 35.4 | 156 | (384) | (25.1) | 723 | 153 | 876 | 57.4 | 1,416 | 92.7 |
| 37 | 2020 | 519 | 519 | 34.0 | 156 | (363) | (23.8) | 773 | 153 | 926 | 60.7 | 1,445 | 94.7 |
| 38 | 2021 | 501 | 501 | 32.8 | 158 | (343) | (22.5) | 825 | 153 | 978 | 64.1 | 1,479 | 96.9 |
| 39 | 2022 | 488 | 488 | 31.9 | 158 | (329) | (21.6) | 878 | 153 | 1,031 | 67.5 | 1,519 | 99.5 |
| 40 | 2023 | 477 | 477 | 31.2 | 160 | (317) | (20.8) | 933 | 153 | 1,085 | 71.1 | 1,562 | 102.3 |
| 41 | 2024 | 415 | 415 | 27.2 | 164 | (251) | (16.4) | 988 | 153 | 1,141 | 74.7 | 1,556 | 101.9 |
| 42 | 2025 | 404 | 404 | 26.4 | 164 | (240) | (15.7) | 1,046 | 153 | 1,198 | 78.5 | 1,602 | 104.9 |
| 45 | Net Present Value | 8,726 | 8,726 | | 20,058 | 11,332 | | 12,688 | 2,811 | 15,499 | | 24,226 | |
| 46 | Nominal Levelized Cost ($/MWh) | | | 39.5 | | | 51.3 | | | | 70.2 | | 109.7 |
| 47 | Real Levelized Cost ($/MWh) | | | 30.9 | | | 40.2 | | | | 55.0 | | 85.9 |

CONFIDENTIAL

# 10.8 MW Bi-Fuel Fired Recips -- Online July 2001 -- Lease Option

## Avista Corporation

## Economic Analysis Detail

### Assumptions

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Installed Cost | 310 | $000s | Fixed Charge | 0.00 | per kW-month | Variable O&M | 10.00 | 2001$/MWh | Electric Wheeling Losses | 0.0 | percent |
| Project Capacity | 10.8 | MW | Fixed O&M | 0.45 | 2003$ per kW-month | | | | | | |
| Heat Rate | 9,615 | Btu/kWh | Escalation Rates | | | Insurance Cost | 0.93 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.77 | percent |
| Peak Gas Useage | 2,492 | 000s dth | Fixed O&M | 2.5 | percent | Gas Transport | 0.00 | 2000 $/dth | Real Discount Rate | 5.1 | percent |
| | | | Variable O&M | 2.5 | percent | Electric Wheeling | 0 | $/MW-month thru 2006 | | | |
| | | | Transportation | 2.5 | percent | General Inflation | 2.5 | percent | | | |

| IRR | Profitability Index |
|---|---|
| | 38.46 |

| | | | Fixed Costs | | | | | | | | | | | Total Fixed Costs | | | Less | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Capital Recovery and Miscellaneous | | | | Operations & Maintenance | | | | | | | Before 10% | After 10% | After 10% | Operating | Net | | Variable Costs | | | | Total Project Cost | |
| Year | | Energy | Project | Fixed Chrg. | Total Costs | | Fixed | Gtrans | Etrans | PrTax | Insur. | Total Costs | | Credit | Credit | Credit | Margin | Project Benefit | | Gas | O&M | Total Variable | | after Credits | |
| | | (GWh) | ($000s) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($000s) | ($000s) | ($000s) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($/MWh) |
| 1 | 2001 | 45.3 | 323 | 0 | 323 | 7.1 | 56 | 0 | 0 | 4 | 1 | 61 | 1.3 | 384 | 384 | 8.5 | 10,345 | 9,961 | 219.8 | 3,120 | 2,545 | 5,665 | 125.0 | 6,049 | 133.5 |
| 2 | 2002 | 44.6 | 309 | 0 | 309 | 6.9 | 57 | 0 | 0 | 4 | 1 | 62 | 1.4 | 371 | 371 | 8.3 | 3,483 | 3,111 | 69.8 | 2,866 | 2,538 | 5,404 | 121.2 | 5,775 | 129.6 |
| 3 | 2003 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 4 | 2004 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 5 | 2005 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 6 | 2006 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 7 | 2007 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 8 | 2008 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 9 | 2009 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 10 | 2010 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 11 | 2011 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 12 | 2012 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 13 | 2013 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 14 | 2014 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 15 | 2015 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 16 | 2016 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 17 | 2017 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 18 | 2018 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 19 | 2019 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 20 | 2020 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 21 | 2021 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 22 | 2022 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 23 | 2023 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 24 | 2024 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 25 | 2025 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | (0) | 0 | (0) | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | (0) | #DIV/0! |
| 2001$ | | | | | | | | | | | | | | | | | | | | | | | | | |
| Net Present Value | | | 566 | 0 | 566 | | 100 | 0 | 0 | 5 | 2 | 107 | | 673 | 673 | | 12,598 | 11,922 | | 5,363 | 4,546 | 9,909 | | 10,583 | |
| Nominal Levelized Cost ($/MWh) | | | | | | 7.0 | | | | | | | 1.3 | | | 8.4 | | | 148.3 | | | | 123.3 | | 131.6 |
| Real Levelized Cost ($/MWh) | | | | | | 6.8 | | | | | | | 1.3 | | | 8.1 | | | 143.0 | | | | 118.8 | | 126.9 |

# CONFIDENTIAL

DRAFT
JRT 10/2/00

## Avista Utilities
## Gas/Electric Transaction

Date of Transaction: 5-10-01 Reference No. ____________

Transaction Details: Purchase / Sale (Circle)

Delivery Period 7/1/01 – 11/30/1

Volume 10.8 MW, ≈ 7300 mwh/month

Location Kettle Falls – Bi-Fuel Units

Price $208/mwh (5 month operation)

Broker ____________

Market Conditions: Ave. flat forward market for July–Nov 2001 is approximately $322/mwh. Ave. total cost of these Bi-Fuel generators is $208/mwh. ($126/mwh–fixed; $82/mwh variable) If units operate longer than 5 months, then fixed cost drops proportionally.

System Position and Reason for Action (Attach Position Report): Small generation project is to protect from short-term resource deficiencies, variability in available hydro, variability in loads, and generation unit outage risk.

Dispatchability: Yes. Similar to a call option, with a strike price at the variable cost of operation

Transmission Alternatives: N/A. On the Avista system.

Building Options: This is a build option. Avista will lease the units for a one year period. The 5 month operation is conservative. If the small C.T. planned for Kettle Falls is not operational by 12/1/01, then these units will operate longer. (And lower fixed cost)

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Financial and Rate Impacts: This is a better option for serving customers than the market

Market Quotes: Broker ____________ Quote ______________

Broker ____________ Quote ______________

Broker ____________ Quote ______________

Completed by: Bob Lafferty Date: 5-10-01

# CONFIDENTIAL

CONFIDENTIAL: For Intern' 'se Only

**Avista ''ilities**
**Positi eport**
**2001-05-10.xls**

Indicates positions outside of risk policy limits

| Month | Hrs | Index Purchase (Sale) [a] | Physical Position Long (Short) [b] | Financial Put (Call) Net Delta [c] | Total Position Long (Short) [d] | CT Inc in Phy Fuel Pur | CT Turb. Fuel Not Pur [e] | Physical Open Position [f] | Financial Open Position [g] | Financial Quarter Average | Fin & NG Open Position [h] | Month Short Limit | Month Long Limit | Fin & NG Quarter Average | Quarter Short Limit | Quarter Long Limit | Month | Hrs | Hrs | Impact of $50 Price Increase |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Col (1) | Col (2) | Col (3) | Col (4) Col (2) + Col (3) | Col (5) | Col (6) | Col (7) Col (4) + Col (6) | Col (8) Col (7) - Col (1) | Col (9) Avg Col 8 | Col (10) Col (8) - Col (6) | Col (11) | Col (12) | Col (13) Avg Col 10 | Col (14) | Col (15) | | | | |
| Jun-01 | HL | (5) | (30) | 0 | (30) | 124 | 0 | (30) | (25) | | (25) | (25) | 125 | | | | Jun-01 | HL | 416 | $ (526,450) |
| Jun-01 | LL | (5) | 52 | 0 | 52 | 120 | 0 | 52 | 57 | | 57 | (25) | 125 | | | | Jun-01 | LL | 304 | $ 869,000 |
| Jul-01 | HL | (5) | (30) | 0 | (30) | 150 | 0 | (30) | (25) | | (25) | (75) | 200 | | | | Jul-01 | HL | 400 | $ (509,150) |
| Jul-01 | LL | (5) | 16 | 0 | 16 | 150 | 0 | 16 | 21 | | 21 | (75) | 200 | | | | Jul-01 | LL | 344 | $ 364,950 |
| Aug-01 | HL | 5 | (21) | 0 | (21) | 200 | 0 | (21) | (26) | 7 | (26) | (75) | 200 | 7 | (25) | 150 | Aug-01 | HL | 432 | $ (562,450) |
| Aug-01 | LL | 5 | 46 | 0 | 46 | 200 | 0 | 46 | 41 | 57 | 41 | (75) | 200 | 57 | (25) | 150 | Aug-01 | LL | 312 | $ 642,000 |
| Sep-01 | HL | (5) | 67 | 0 | 67 | 208 | 0 | 67 | 72 | | 72 | (75) | 200 | | | | Sep-01 | HL | 384 | $ 1,388,200 |
| Sep-01 | LL | (5) | 103 | 0 | 103 | 208 | 0 | 103 | 108 | | 108 | (75) | 200 | | | | Sep-01 | LL | 336 | $ 1,810,800 |
| Oct-01 | HL | (5) | (42) | 0 | (42) | 208 | 0 | (42) | (37) | | (37) | (150) | 250 | | | | Oct-01 | HL | 432 | $ (795,750) |
| Oct-01 | LL | (5) | 101 | 0 | 101 | 208 | 0 | 101 | 106 | | 106 | (150) | 250 | | | | Oct-01 | LL | 312 | $ 1,650,400 |
| Nov-01 | HL | (5) | 71 | 0 | 71 | 219 | 0 | 71 | 76 | 48 | 76 | (150) | 250 | 48 | (50) | 150 | Nov-01 | HL | 400 | $ 1,516,600 |
| Nov-01 | LL | (5) | 86 | (88) | (2) | 160 | 0 | (2) | 3 | 27 | 3 | (150) | 250 | 27 | (50) | 150 | Nov-01 | LL | 320 | $ 49,200 |
| Dec-01 | HL | (5) | 100 | 0 | 100 | 219 | 0 | 100 | 105 | | 105 | (150) | 250 | | | | Dec-01 | HL | 400 | $ 2,098,000 |
| Dec-01 | LL | (5) | 41 | (75) | (34) | 160 | 0 | (34) | (29) | | (29) | (150) | 250 | | | | Dec-01 | LL | 344 | $ (497,950) |
| Jan-02 | HL | (5) | 82 | 0 | 82 | 99 | 61 | 143 | 148 | | 87 | (150) | 250 | | | | Jan-02 | HL | 416 | $ 3,085,500 |
| Jan-02 | LL | (5) | 114 | (68) | 46 | 99 | 61 | 107 | 112 | | 51 | (150) | 250 | | | | Jan-02 | LL | 328 | $ 1,835,700 |
| Feb-02 | HL | (5) | 73 | 0 | 73 | 99 | 41 | 114 | 119 | 132 | 78 | (150) | 250 | 91 | (50) | 150 | Feb-02 | HL | 384 | $ 2,286,300 |
| Feb-02 | LL | (5) | 164 | (81) | 83 | 99 | 41 | 124 | 129 | 123 | 88 | (150) | 250 | 82 | (50) | 150 | Feb-02 | LL | 288 | $ 1,864,450 |
| Mar-02 | HL | (5) | 103 | 0 | 103 | 99 | 19 | 122 | 127 | | 108 | (150) | 250 | | | | Mar-02 | HL | 416 | $ 2,645,200 |
| Mar-02 | LL | (5) | 185 | (83) | 101 | 99 | 20 | 121 | 126 | | 106 | (150) | 250 | | | | Mar-02 | LL | 328 | $ 2,068,100 |
| Apr-02 | HL | (5) | 172 | (74) | 98 | 99 | 56 | 154 | 159 | | 103 | (150) | 250 | | | | Apr-02 | HL | 416 | $ 3,307,950 |
| Apr-02 | LL | (5) | 173 | (56) | 117 | 99 | 56 | 173 | 178 | | 122 | (150) | 250 | | | | Apr-02 | LL | 304 | $ 2,703,900 |
| May-02 | HL | (5) | 197 | 0 | 197 | 99 | 47 | 244 | 249 | 210 | 202 | (150) | 250 | 175 | (50) | 150 | May-02 | HL | 416 | $ 5,188,000 |
| May-02 | LL | (5) | 174 | 0 | 174 | 99 | 44 | 218 | 223 | 208 | 179 | (150) | 250 | 174 | (50) | 150 | May-02 | LL | 328 | $ 3,659,550 |
| Jun-02 | HL | (5) | 290 | (75) | 215 | 119 | 0 | 215 | 220 | | 220 | (150) | 250 | | | | Jun-02 | HL | 400 | $ 4,401,200 |
| Jun-02 | LL | (5) | 294 | (76) | 217 | 119 | 0 | 217 | 222 | | 222 | (150) | 250 | | | | Jun-02 | LL | 320 | $ 3,557,250 |
| Jul-02 | HL | (5) | 244 | 0 | 244 | 150 | 0 | 244 | 249 | | 249 | (175) | 250 | | | | Jul-02 | HL | 416 | $ 5,175,700 |
| Jul-02 | LL | (5) | 215 | 0 | 215 | 150 | 0 | 215 | 220 | | 220 | (175) | 250 | | | | Jul-02 | LL | 328 | $ 3,608,200 |
| Aug-02 | HL | 5 | (51) | 0 | (51) | 260 | 200 | 149 | 144 | 192 | (56) | (175) | 250 | 56 | (75) | 150 | Aug-02 | HL | 432 | $ 3,121,050 |
| Aug-02 | LL | 5 | 245 | 0 | 245 | 260 | 200 | 445 | 441 | 378 | 241 | (175) | 250 | 242 | (75) | 150 | Aug-02 | LL | 312 | $ 6,872,350 |
| | | | | | | | | | | | | | | | | | Jan-00 | 0 | | |
| Sep-02 | HL | (5) | (32) | 0 | (32) | 265 | 208 | 176 | 181 | | (27) | (175) | 250 | | | | Sep-02 | HL | 384 | $ 3,483,550 |
| Sep-02 | LL | (5) | 261 | 0 | 261 | 265 | 208 | 469 | 474 | | 266 | (175) | 250 | | | | Sep-02 | LL | 336 | $ 7,963,050 |
| Oct-02 | HL | (5) | 88 | 0 | 88 | 265 | 208 | 296 | 301 | | 93 | (175) | 250 | | | | Oct-02 | HL | 432 | $ 6,500,150 |
| Oct-02 | LL | (5) | 265 | 0 | 265 | 265 | 208 | 473 | 478 | | 270 | (175) | 250 | | | | Oct-02 | LL | 312 | $ 7,452,700 |
| Nov-02 | HL | (5) | 249 | 0 | 249 | 270 | 218 | 467 | 472 | | 254 | (175) | 250 | | | | Nov-02 | HL | 400 | $ 9,438,350 |
| Nov-02 | LL | (5) | 325 | (44) | 280 | 270 | 160 | 440 | 445 | | 285 | (175) | 250 | | | | Nov-02 | LL | 320 | $ 7,122,850 |

Footnotes: [a] Index transactions are already included in the total physical position. [b] Physical position. [c] Aggregate physical equivalent (delta) position of options (put and calls). [d] Total position is the combined physical and delta positions. [e] Turbines in this column are available for use, but gas has not been purchased. When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column. [f] Open physical position includes total position and available turbines. [g] Open financial position includes open physical position less any index position. [h] Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased. At its meeting on May 3, 2001, the Risk Management Committee suspended the cure date for the positions in Q2 02, Q3 02, Sep 02, Oct 02, and Nov 02 which are longer than the long limits. These positions will be re-evaluated on a monthly basis by the Risk Management Committee.

**AVISTA Corporation**

*Energy Resources*

**Situation**

Although the company has worked hard to balance the utility's load and resource positions, there is considerable reliance on fully-available generation and consistent loads. It is prudent for us to protect ourselves from unit outage risk and volatile loads, and building additional generation is one such way to obtain that protection.

**Boulder Park Generation**

We have received an offer for 32.8 megawatts of generation that would fit well in a site in the Spokane valley. The site is between Barker and Campbell Roads just south of Trent. The generation package consists of eight natural gas-fueled reciprocating engine generators with capacities each of 4.1MW. Benefits of the generation include the quick time to operation (estimated to be September 1, 2001) and the high efficiency of the equipment. Issues associated with this generation include:

- **Air Permit** – Spokane County allows temporary generation to be installed for no longer than six months. Given the costs associated with installing this generation, it is prudent to operate the generation for a period greater than six months, so a temporary permit is not feasible. The standard permitting process could take 90-120 days. If the permit does take 120 days to secure, the project operation could be delayed as much as two weeks, but the overall economic value of the project would not significantly change based on forward market prices.
- **Property** – Avista Development owns the property on which this generation would be developed. The property is zoned industrial.
- **Building Permit** – This generation must be housed in a building. Normally, building permits take eight to twelve weeks.
- **Electrical Interconnection** – A limited substation needs to be built near the generation, but the Avista system can easily integrate the 33MW.
- **Gas Supply** – The supply pipeline runs along Trent just north of the location and can be accessed with a tap and regulator. The Avista system can support this fuel need.
- **Reliability** – Due to the small unit configuration, the company benefits from the diversification, and there is limited risk that all 32.8 megawatts would trip at once.
- **Economics** – Because this generation would be used to protect against unit outages and fluctuating loads, the output of this generation would not be pre-sold into the market. However, on a short-term basis, as loads and resources permit, the generation could be sold into the market when economics support the transaction. Doing so would reduce the electric deferral balance. Based on the attached revenue requirement model, this project would have a positive net project benefit of $40.6 million over the life of the generation if constructed and operational in September 2001. The tremendous benefits of this project exist due to the high efficiency of reciprocating gas engines and the relatively quick time to operation.

Additional questions can be directed to Tom Barker or Jason Thackston.

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Met with
Operational Council
4/30/01

BOULDER PARK
WARTSILAS

# Avista Utilities
# Gas/Electric Transaction

Date of Transaction: 4/27/01 Reference No. N/A

Transaction Details: Purchase / Sale (Circle)

Delivery Period Beginning 9/1/01

Volume 32.8MW

Location Boulder Park (South of Trent Between Barker + Campbell)

Price ≈$23 million @ installed

Broker N/A

Market Conditions: Day ahead prices are above $300 - Q3 to above $400. Very volatile market place

System Position and Reason for Action (Attach Position Report): attached Close to balanced without consideration for variable loads & hydro generation. Purchased this generation to protect customers/company from price spikes

Dispatchability of Product: Fully dispatchable in 4.1MW increments

Transmission Alternatives: N/A

Building Options: Compared to other generation available this quickly, this option is favorable.

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Financial and Rate Impacts: Fixes the capital cost against a much higher forward market. Compared to the forward market, the generation has a net project benefit of $40.6 mm.

Market Quotes: Broker ______ Quote ______

Broker ______ Quote ______

Broker ______ Quote ______

This is a long-term product compared to prices gathered by Avista's Risk Management/Accounting groups. There is no standard market product ~~for~~ that matche this generation.

Completed by: Jason Thackston Date: ______

Jason Thackston

JRT 10/2/00

**AVISTA Corporation**

*Energy Resources*

**Boulder Park/Spokane Industrial Park Generation**
Memo to files for Boulder Park and SIP
Prepared by Jason Thackston
5/18/01

Avista has already committed to eight Wartsila natural gas fired reciprocating engines with capacities each of 4.1MW. At the time the initial commitment was made toWartsila, the intention was to site all eight units at Boulder Park, and the positive NPV of the project was about $40.6 million. Subsequent to air emissions modeling, it has been determined that all eight units cannot be placed in the same location. Six units will be placed at Boulder Park and the remaining two units will be sited at Spokane Industrial Park with the potential for expansion at a later time.

Market prices have changed significantly since the initial analysis, but the eight units still provide the company with a positive NPV of $10.6 million. Boulder Park has a positive NPV of $11 million and SIP has a negative NPV of about $360 thousand.

All 8 units @ Boulder Park
5/1/01 Analysis

# CONFIDENTIAL

## "32.864 MW Recips At Boulder Park -- Online Sep 1,2001

### Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Installed Cost | 23,000 | $000s | Fixed Charge | 0.00 | per kW-month | Variable O&M | 5.00 | 2001$/MWh | Electric Wheeling Losses | 0.0 | percent |
| Project Capacity | 32.9 | MW | Fixed O&M | 0.45 | 2003$ per kW-month | | | | | | |
| Heat Rate | 8,250 | Btu/kWh | Escalation Rates | | | Insurance Cost | 69.00 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.77 | percent |
| Peak Gas Usage | 6,507 | 000s dth | Fixed O&M | 2.5 | percent | Gas Transport | 0.00 | 2000 $/dth | Real Discount Rate | 5.1 | percent |
| | | | Variable O&M | 2.5 | percent | Electric Wheeling | 0 | $/MW-month thru 2006 | | | |
| | | | Transportation | 2.5 | percent | General Inflation | 2.5 | percent | | | |

| IRR | Profitability Index |
|---|---|
| 46.4050% | 1.77 |

**Fixed Costs**

| Row | Year | | Energy | Capital Recovery and Miscellaneous: Project | Fixed Chrg. | Total Costs | | Operations & Maintenance: Fixed | Gtrans | Etrans | PrTax | Insur. | Total Costs | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 17 | | | (GWh) | ($000s) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($000s) | ($000s) | ($000s) | ($000s) | ($000s) | ($/MWh) |
| 18 | 1 | 2001 | 89.5 | 4,410 | 0 | 4,410 | 49.3 | 0 | 0 | 0 | 308 | 69 | 377 | 4.2 |
| 19 | 2 | 2002 | 267.7 | 4,746 | 0 | 4,746 | 17.7 | 173 | 0 | 0 | 292 | 71 | 536 | 2.0 |
| 20 | 3 | 2003 | 267.7 | 4,367 | 0 | 4,367 | 16.3 | 177 | 0 | 0 | 276 | 72 | 526 | 2.0 |
| 21 | 4 | 2004 | 178.2 | 3,966 | 0 | 3,966 | 22.2 | 182 | 0 | 0 | 259 | 74 | 516 | 2.9 |
| 22 | 5 | 2005 | 155.5 | 3,758 | 0 | 3,758 | 24.2 | 186 | 0 | 0 | 243 | 76 | 506 | 3.3 |
| 23 | 6 | 2006 | 155.5 | 3,612 | 0 | 3,612 | 23.2 | 191 | 0 | 0 | 227 | 78 | 496 | 3.2 |
| 24 | 7 | 2007 | 155.5 | 3,468 | 0 | 3,468 | 22.3 | 196 | 0 | 0 | 211 | 80 | 487 | 3.1 |
| 25 | 8 | 2008 | 157.7 | 3,289 | 0 | 3,289 | 20.9 | 201 | 0 | 0 | 195 | 82 | 477 | 3.0 |
| 26 | 9 | 2009 | 267.7 | 3,276 | 0 | 3,276 | 12.2 | 206 | 0 | 0 | 178 | 84 | 468 | 1.7 |
| 27 | 10 | 2010 | 267.7 | 3,149 | 0 | 3,149 | 11.8 | 211 | 0 | 0 | 162 | 86 | 459 | 1.7 |
| 28 | 11 | 2011 | 267.7 | 3,024 | 0 | 3,024 | 11.3 | 216 | 0 | 0 | 146 | 88 | 450 | 1.7 |
| 29 | 12 | 2012 | 268.5 | 2,900 | 0 | 2,900 | 10.8 | 222 | 0 | 0 | 130 | 91 | 442 | 1.6 |
| 30 | 13 | 2013 | 267.7 | 2,775 | 0 | 2,775 | 10.4 | 227 | 0 | 0 | 113 | 93 | 433 | 1.6 |
| 31 | 14 | 2014 | 267.7 | 2,652 | 0 | 2,652 | 9.9 | 233 | 0 | 0 | 97 | 95 | 425 | 1.6 |
| 32 | 15 | 2015 | 267.7 | 2,533 | 0 | 2,533 | 9.5 | 239 | 0 | 0 | 81 | 97 | 417 | 1.6 |
| 33 | 16 | 2016 | 268.5 | 2,414 | 0 | 2,414 | 9.0 | 245 | 0 | 0 | 65 | 100 | 409 | 1.5 |
| 34 | 17 | 2017 | 267.7 | 2,294 | 0 | 2,294 | 8.6 | 251 | 0 | 0 | 49 | 102 | 402 | 1.5 |
| 35 | 18 | 2018 | 267.7 | 2,172 | 0 | 2,172 | 8.1 | 257 | 0 | 0 | 32 | 105 | 394 | 1.5 |
| 36 | 19 | 2019 | 132.8 | 1,751 | 0 | 1,751 | 13.2 | 263 | 0 | 0 | 16 | 108 | 387 | 2.9 |
| 37 | 20 | 2020 | 0.0 | 1,315 | 0 | 1,315 | #DIV/0! | 270 | 0 | 0 | 0 | 110 | 380 | #DIV/0! |
| 38 | 21 | 2021 | 0.0 | 30 | 0 | 30 | #DIV/0! | 277 | 0 | 0 | 0 | 113 | 390 | #DIV/0! |
| 39 | 22 | 2022 | 0.0 | 0 | 0 | 0 | #DIV/0! | 284 | 0 | 0 | 0 | 116 | 400 | #DIV/0! |
| 40 | 23 | 2023 | 0.0 | 0 | 0 | 0 | #DIV/0! | 291 | 0 | 0 | 0 | 119 | 410 | #DIV/0! |
| 41 | 24 | 2024 | 0.0 | 0 | 0 | 0 | #DIV/0! | 149 | 0 | 0 | 0 | 122 | 271 | #DIV/0! |
| 42 | 25 | 2025 | 0.0 | 0 | 0 | 0 | #DIV/0! | 153 | 0 | 0 | 0 | 125 | 278 | #DIV/0! |
| 44 | *2001$* | | | | | | | | | | | | | |
| 45 | Net Present Value | | | 34,493 | 0 | 34,493 | | 2,085 | 0 | 0 | 1,927 | 935 | 4,948 | |
| 46 | Nominal Levelized Cost ($/MWh) | | | | | | 14.2 | | | | | | | 2.7 |
| 47 | Real Levelized Cost ($/MWh) | | | | | | 11.1 | | | | | | | 2.1 |

| Row | Year | Total Fixed Costs: Before 10% Credit | After 10% Credit | After 10% Credit | Less Operating Margin | Net Project Benefit | | Variable Costs: Gas | O&M | Total Variable | | Total Project Cost after Credits | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 17 | | ($000s) | ($000s) | ($/MWh) | ($000s) | -23,000 | ($/MWh) | ($000s) | ($000s) | ($000s) | ($/MWh) | ($000s) | ($/MWh) |
| 18 | 2001 | 4,787 | 4,787 | 53.5 | 21,664 | 16,877 | 188.6 | 7,031 | 447 | 7,478 | 83.6 | 12,266 | 137.1 |
| 19 | 2002 | 5,282 | 5,282 | 19.7 | 28,491 | 23,209 | 86.7 | 16,115 | 1,339 | 17,453 | 65.2 | 22,735 | 84.9 |
| 20 | 2003 | 4,893 | 4,893 | 18.3 | 7,760 | 2,868 | 10.7 | 11,650 | 1,339 | 12,989 | 48.5 | 17,882 | 66.8 |
| 21 | 2004 | 4,481 | 4,481 | 25.1 | 5,174 | 693 | 3.9 | 7,046 | 891 | 7,937 | 44.5 | 12,418 | 69.7 |
| 22 | 2005 | 4,264 | 4,264 | 27.4 | 3,475 | (789) | (5.1) | 6,065 | 778 | 6,842 | 44.0 | 11,107 | 71.4 |
| 23 | 2006 | 4,108 | 4,108 | 26.4 | 2,002 | (2,106) | (13.5) | 6,148 | 778 | 6,925 | 44.5 | 11,033 | 71.0 |
| 24 | 2007 | 3,955 | 3,955 | 25.4 | 1,246 | (2,709) | (17.4) | 6,195 | 778 | 6,972 | 44.8 | 10,927 | 70.3 |
| 25 | 2008 | 3,766 | 3,766 | 23.9 | 2,964 | (802) | (5.1) | 5,406 | 789 | 6,195 | 39.3 | 9,961 | 63.2 |
| 26 | 2009 | 3,745 | 3,745 | 14.0 | 4,552 | 807 | 3.0 | 7,525 | 1,339 | 8,863 | 33.1 | 12,608 | 47.1 |
| 27 | 2010 | 3,609 | 3,609 | 13.5 | 4,834 | 1,225 | 4.6 | 7,788 | 1,339 | 9,127 | 34.1 | 12,735 | 47.6 |
| 28 | 2011 | 3,474 | 3,474 | 13.0 | 4,918 | 1,444 | 5.4 | 8,085 | 1,339 | 9,424 | 35.2 | 12,898 | 48.2 |
| 29 | 2012 | 3,342 | 3,342 | 12.4 | 5,713 | 2,371 | 8.8 | 8,423 | 1,342 | 9,766 | 36.4 | 13,108 | 48.8 |
| 30 | 2013 | 3,208 | 3,208 | 12.0 | 4,865 | 1,657 | 6.2 | 8,721 | 1,339 | 10,059 | 37.6 | 13,267 | 49.6 |
| 31 | 2014 | 3,078 | 3,078 | 11.5 | 5,013 | 1,935 | 7.2 | 9,085 | 1,339 | 10,423 | 38.9 | 13,501 | 50.4 |
| 32 | 2015 | 2,950 | 2,950 | 11.0 | 4,948 | 1,998 | 7.5 | 9,507 | 1,339 | 10,846 | 40.5 | 13,796 | 51.5 |
| 33 | 2016 | 2,824 | 2,824 | 10.5 | 4,912 | 2,088 | 7.8 | 9,947 | 1,342 | 11,289 | 42.1 | 14,113 | 52.6 |
| 34 | 2017 | 2,695 | 2,695 | 10.1 | 4,860 | 2,164 | 8.1 | 10,343 | 1,339 | 11,681 | 43.6 | 14,377 | 53.7 |
| 35 | 2018 | 2,566 | 2,566 | 9.6 | 4,849 | 2,283 | 8.5 | 10,716 | 1,339 | 12,055 | 45.0 | 14,621 | 54.6 |
| 36 | 2019 | 2,138 | 2,138 | 16.1 | 1,119 | (1,020) | (7.7) | 5,520 | 664 | 6,184 | 46.6 | 8,322 | 62.7 |
| 37 | 2020 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 38 | 2021 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 39 | 2022 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 40 | 2023 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 41 | 2024 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 42 | 2025 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 45 | Net Present Value | 38,736 | 38,736 | | 79,383 | 40,648 | | 83,768 | 10,374 | 94,142 | | 132,878 | |
| 46 | Nominal Levelized Cost ($/MWh) | | | 17.4 | | | 18.2 | | | | 51.0 | | 72.0 |
| 47 | Real Levelized Cost ($/MWh) | | | 14.1 | | | 14.8 | | | | 40.0 | | 56.4 |

Source - Dave DeFelice
5/1/01

*Avis 'tilities*
**Posi. . Report**
**2001-04-27.xls**

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Indicates positions outside of risk policy limits

| Month | Hrs | Index Purchase (Sale) [a] | Physical Position Long (Short) [b] | Financial Put (Call) Net Delta [c] | **Total Position** Long (Short) [d] | CT Inc in Phy Fuel Pur | CT Turb. Fuel Not Pur [e] | **Physical Open Position [f]** | **Financial Open Position [g]** | **Financial Quarter Average** | **Fin & NG Open Position [h]** | Month Short Limit | Month Long Limit | **Fin & NG Quarter Average** | Quarter Short Limit | Quarter Long Limit | Month | Hrs | Hrs | Impact of $50 Price Increase |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Col (1) | Col (2) | Col (3) | Col (4) Col (2) + Col (3) | Col (5) | Col (6) | Col (7) Col (4) + Col (6) | Col (8) Col (7) - Col (1) | Col (9) Avg Col 8 | Col (10) Col (8) - Col (6) | Col (11) | Col (12) | Col (13) Avg Col 10 | Col (14) | Col (15) | | | | |
| May-01 | HL | (5) | 17 | 0 | **17** | 123 | 58 | **75** | **80** | | **22** | (25) | 125 | | | | May-01 | HL | 416 | $ 1,661,450 |
| May-01 | LL | (5) | 23 | 0 | **23** | 121 | 55 | **78** | **83** | | **28** | (25) | 125 | | | | May-01 | LL | 328 | $ 1,359,450 |
| Jun-01 | HL | (5) | (30) | 0 | **(30)** | 124 | 0 | **(30)** | **(25)** | | **(25)** | (25) | 125 | | | | Jun-01 | HL | 416 | $ (526,450) |
| Jun-01 | LL | (5) | 52 | 0 | **52** | 120 | 0 | **52** | **57** | | **57** | (25) | 125 | | | | Jun-01 | LL | 304 | $ 869,000 |
| Jul-01 | HL | (5) | (30) | 0 | **(30)** | 150 | 0 | **(30)** | **(25)** | | **(25)** | (75) | 200 | | | | Jul-01 | HL | 400 | $ (509,150) |
| Jul-01 | LL | (5) | 16 | 0 | **16** | 150 | 0 | **16** | **21** | | **21** | (75) | 200 | | | | Jul-01 | LL | 344 | $ 364,950 |
| Aug-01 | HL | 5 | (21) | 0 | **(21)** | 200 | 0 | **(21)** | **(26)** | **5** | **(26)** | (75) | 200 | **5** | (25) | 150 | Aug-01 | HL | 432 | $ (565,750) |
| Aug-01 | LL | 5 | 46 | 0 | **46** | 200 | 0 | **46** | **41** | **57** | **41** | (75) | 200 | **57** | (25) | 150 | Aug-01 | LL | 312 | $ 641,400 |
| Sep-01 | HL | (5) | 63 | 0 | **63** | 208 | 0 | **63** | **68** | | **68** | (75) | 200 | | | | Sep-01 | HL | 384 | $ 1,298,200 |
| Sep-01 | LL | (5) | 103 | 0 | **103** | 208 | 0 | **103** | **108** | | **108** | (75) | 200 | | | | Sep-01 | LL | 336 | $ 1,810,800 |
| Oct-01 | HL | (5) | (17) | 0 | **(17)** | 208 | 0 | **(17)** | **(12)** | | **(12)** | (150) | 250 | | | | Oct-01 | HL | 432 | $ (255,750) |
| Oct-01 | LL | (5) | 101 | 0 | **101** | 208 | 0 | **101** | **106** | | **106** | (150) | 250 | | | | Oct-01 | LL | 312 | $ 1,650,400 |
| Nov-01 | HL | (5) | 96 | 0 | **96** | 219 | 0 | **96** | **101** | **71** | **101** | (150) | 250 | **71** | (50) | 150 | Nov-01 | HL | 400 | $ 2,016,600 |
| Nov-01 | LL | (5) | 86 | (90) | **(3)** | 160 | 0 | **(3)** | **2** | **25** | **2** | (150) | 250 | **25** | (50) | 150 | Nov-01 | LL | 320 | $ 28,800 |
| Dec-01 | HL | (5) | 120 | 0 | **120** | 219 | 0 | **120** | **125** | | **125** | (150) | 250 | | | | Dec-01 | HL | 400 | $ 2,496,600 |
| Dec-01 | LL | (5) | 41 | (79) | **(38)** | 160 | 0 | **(38)** | **(33)** | | **(33)** | (150) | 250 | | | | Dec-01 | LL | 344 | $ (569,550) |
| Jan-02 | HL | (5) | 107 | 0 | **107** | 99 | 61 | **168** | **173** | | **112** | (150) | 250 | | | | Jan-02 | HL | 416 | $ 3,605,500 |
| Jan-02 | LL | (5) | 114 | (70) | **44** | 99 | 61 | **105** | **110** | | **49** | (150) | 250 | | | | Jan-02 | LL | 328 | $ 1,806,900 |
| Feb-02 | HL | (5) | 98 | 0 | **98** | 99 | 41 | **139** | **144** | **157** | **103** | (150) | 250 | **116** | (50) | 150 | Feb-02 | HL | 384 | $ 2,766,300 |
| Feb-02 | LL | (5) | 164 | (82) | **82** | 99 | 41 | **123** | **128** | **120** | **87** | (150) | 250 | **79** | (50) | 150 | Feb-02 | LL | 288 | $ 1,847,950 |
| Mar-02 | HL | (5) | 128 | 0 | **128** | 99 | 19 | **147** | **152** | | **133** | (150) | 250 | | | | Mar-02 | HL | 416 | $ 3,165,200 |
| Mar-02 | LL | (5) | 181 | (84) | **97** | 99 | 20 | **117** | **122** | | **102** | (150) | 250 | | | | Mar-02 | LL | 328 | $ 1,993,400 |
| Apr-02 | HL | (5) | 148 | (91) | **57** | 99 | 56 | **113** | **118** | | **62** | (150) | 250 | | | | Apr-02 | HL | 416 | $ 2,451,500 |
| Apr-02 | LL | (5) | 145 | (53) | **92** | 99 | 56 | **148** | **153** | | **97** | (150) | 250 | | | | Apr-02 | LL | 304 | $ 2,323,750 |
| May-02 | HL | (5) | 197 | 0 | **197** | 99 | 47 | **244** | **249** | **188** | **202** | (150) | 250 | **154** | (50) | 150 | May-02 | HL | 416 | $ 5,188,000 |
| May-02 | LL | (5) | 174 | 0 | **174** | 99 | 44 | **218** | **223** | **201** | **179** | (150) | 250 | **167** | (50) | 150 | May-02 | LL | 328 | $ 3,659,550 |
| Jun-02 | HL | (5) | 290 | (97) | **193** | 119 | 0 | **193** | **198** | | **198** | (150) | 250 | | | | Jun-02 | HL | 400 | $ 3,961,200 |
| Jun-02 | LL | (5) | 294 | (73) | **221** | 119 | 0 | **221** | **226** | | **226** | (150) | 250 | | | | Jun-02 | LL | 320 | $ 3,608,850 |
| Jul-02 | HL | (5) | 243 | 0 | **243** | 150 | 0 | **243** | **248** | | **248** | (175) | 250 | | | | Jul-02 | HL | 416 | $ 5,148,200 |
| Jul-02 | LL | (5) | 215 | 0 | **215** | 150 | 0 | **215** | **220** | | **220** | (175) | 250 | | | | Jul-02 | LL | 328 | $ 3,608,200 |
| | | | | | | | | | | | | | | | | | Jan-00 | 0 | | |
| Aug-02 | HL | 5 | (51) | 0 | **(51)** | 260 | 200 | **149** | **144** | **190** | **(56)** | (175) | 250 | **54** | (75) | 150 | Aug-02 | HL | 432 | $ 3,121,050 |
| Aug-02 | LL | 5 | 246 | 0 | **246** | 260 | 200 | **446** | **441** | **378** | **241** | (175) | 250 | **242** | (75) | 150 | Aug-02 | LL | 312 | $ 6,872,350 |
| Sep-02 | HL | (5) | (36) | 0 | **(36)** | 265 | 208 | **172** | **177** | | **(31)** | (175) | 250 | | | | Sep-02 | HL | 384 | $ 3,393,550 |
| Sep-02 | LL | (5) | 261 | 0 | **261** | 265 | 208 | **469** | **474** | | **266** | (175) | 250 | | | | Sep-02 | LL | 336 | $ 7,963,050 |
| Oct-02 | HL | (5) | 88 | 0 | **88** | 265 | 208 | **296** | **301** | | **93** | (175) | 250 | | | | Oct-02 | HL | 432 | $ 6,500,150 |
| Oct-02 | LL | (5) | 265 | 0 | **265** | 265 | 208 | **473** | **478** | | **270** | (175) | 250 | | | | Oct-02 | LL | 312 | $ 7,452,700 |

Footnotes: [a] Index transactions are already included in the total physical position. [b] Physical position. [c] Aggregate physical equivalent (delta) position of options (put and calls). [d] Total position is the combined physical and delta positions. [e] Turbines in this column are available for use, but gas has not been purchased. When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column. [f] Open physical position includes total position and available turbines. [g] Open financial position includes open physical position less any index position. [h] Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased. At its meeting on April 10, 2001, the Risk Management Committee suspended the cure date for the positions in Q2 02, Q3 02, Sep 02, and Oct 02 which are longer than the long limits. These positions will be re-evaluated on a monthly basis by the Risk Management Committee.

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SIP WARTSILAS

# Avista Utilities
## Gas/Electric Transaction

Date of Transaction: 4/27 (5/18 split Boulder/SIP) Reference No. N/A

Transaction Details: Purchase / Sale (Circle)

Delivery Period Beginning 9/1/01

Volume 8.2 MW

Location Spokane Industrial Park

Price $8.55 million

Broker N/A

Market Conditions: Day-ahead prices are hundreds of dollars, and volatile markets continue

System Position and Reason for Action (Attach Position Report): Close to balanced without consideration of variable loads & hydro generation. Purchased this generation to protect customers from price spike

Dispatchability of Product: Fully dispatchable in 4.1 MW increments.

Transmission Alternatives: N/A

Building Options: This is new equipment and compares favorably to bringing other (used) generation online in this timeframe.

JRT 10/2/00

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Financial and Rate Impacts: Fixes the capital cost against a much higher forward market.

Market Quotes: Broker ______ Quote ______ No long-term markets to quote from multiple sources.

Broker ______ Quote ______

Broker ______ Quote ______

Completed by: Jason Thackston Date: ______

JRT 10/2/00

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*Energy Resources*

**Boulder Park/Spokane Industrial Park Generation**
Memo to files for Boulder Park and SIP
Prepared by Jason Thackston
5/18/01

Avista has already committed to eight Wartsila natural gas fired reciprocating engines with capacities each of 4.1MW. At the time the initial commitment was made toWartsila, the intention was to site all eight units at Boulder Park, and the positive NPV of the project was about $40.6 million. Subsequent to air emissions modeling, it has been determined that all eight units cannot be placed in the same location. Six units will be placed at Boulder Park and the remaining two units will be sited at Spokane Industrial Park with the potential for expansion at a later time.

Market prices have changed significantly since the initial analysis, but the eight units still provide the company with a positive NPV of $10.6 million. Boulder Park has a positive NPV of $11 million and SIP has a negative NPV of about $360 thousand.

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**Devil's Gap Temporary Diesel Generation Proposal**
Prepared by Jason Thackston
4/4/01

## Situation

Although the company has worked hard to balance the utility's load and resource positions, there are conditions that require additional short-term supplies of power. It is prudent for us to protect ourselves from short-term deficiencies, variability in available power from hydro projects, variability in loads, and generation unit outage risk given the high prices and volatility evident in the competitive electric power market. Building additional generation suitable for economic short-term supply is one such way to obtain that protection. While the Boulder Park generation, if completed, will add 50.7 megawatts of capacity by mid-July, there is a need for additional generation in the short-term. Given the potential emissions challenges at Boulder Park, it is even more prudent to pursue additional generation.

## Devil's Gap Generation

We have received a proposal for 20 megawatts of diesel generation to be sited near the Devil's Gap substation in Lincoln County. The generation consists of 20 one-megawatt containerized diesel units. Natural gas is not available in the region, so any generation in that area needs to be fueled by alternative sources such as diesel. Issues include:

- **Alternatives to Project** – Avista continues to assess short-term supply through other temporary generation, customer load buy-backs, market purchases, and financial options. The economic analysis for the short-term compares the benefits of the project to the most liquid and available alternative, the over-the-counter energy market. Financial options are unavailable in the marketplace due to the dramatically increased volatility in the market and are not a viable alternative.
- **Air Permit** – Given the short-term nature of this project (the offer contains a one-year rental contract), a temporary one-year permit would be pursued. This generation will be equipped with adequate emissions controls. Permitting will be complete before this generation is available for operation.
- **Property** – Avista owns the property near the substation.
- **Electrical Interconnection** – 20 megawatts can be integrated into Devil's Gap with a spare transformer and spare power circuit breaker, both owned by Avista.
- **Diesel Supply** – Avista has received a quote for diesel delivered to the site – fuel is readily available and could be procured for the one-year period of time.
- **Financing** – Aggreko has directly offered a monthly rental amount for one year. Monthly payments to Aggreko are projected to be about $900,000.
- **Reliability** – Given the multiple units, the risk of losing all 20 megawatts is minimal. Reliability is therefore greater than a single 20 megawatt unit.
- **Efficiency** – The heat rate is calculated to be 10,712.

- **Economics** – Because this generation would be used to protect against unit outages and peaking loads, the output of this generation would not be pre-sold into the market. However, on a short-term basis, as loads and resources permit, the generation could be sold into the market when economics support the transaction. Doing so would be prudent as it reduces the electric deferral balance.

  The following information is based on forward market prices for both diesel and electricity as of this last week. Given the one-year offer from Aggreko, only one scenario has been evaluated – all costs of the project are incurred over the year and the equipment is returned at the end of the period. Results of the analysis are summarized below and detailed in Attachment A:

| | Generation @ 92% Availability (161,184 MWh) | |
|---|---|---|
| | **$/MWh** | **Total Dollars** |
| Fixed Cost to Generate | $ 70.99 | $ 11.4 million |
| Variable Cost to Generate | 91.17 | 14.7 million |
| Total Cost to Generate | 162.16 | 26.1 million |
| Increased Revenue or Decreased Expense | 283.10 | 45.6 million |
| **Project Benefit** | **$ 120.94** | **$ 19.5 Million** |

  This project is beneficial to the system over the next year and is considered a strong alternative to other short-term energy sources. The generation is not intended to be a longer-term solution to Avista's resource needs but fits well into the short-term resource needs for the coming summer and winter. A revenue requirement model was not run on the project, as this has no long-term benefits to the customer. It is assumed that the deferral balance would incorporate the operating costs (including the rent/lease), as the resulting net increased sales or net decreased purchases positively impact the deferral balance in the magnitude listed above.

The analysis of this project assumes an operational date of July 1.

Jason Thackston
April 2, 2001

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**Cash Flow Analysis**
**20MW Aggreko Diese' eration**
**1 Year Lease**

| | | |
|---|---|---|
| Capacity | 20.0 | MW |
| Heat Rate | 10,712 | |
| Load Factor | 92% | |
| Variable Costs/MWh | $ 14.00 | |
| Lease Rate | $ 907,000 | |

| | Totals | Mar-01 | Apr-01 | May-01 | Jun-01 | Jul-01 | Aug-01 | Sep-01 | Oct-01 | Nov-01 | Dec-01 | Jan-02 | Feb-02 | Mar-02 | Apr-02 | May-02 | Jun-02 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hours in Month | 7,272 | | | | | 744 | 744 | 720 | 744 | 720 | 744 | 744 | 672 | 744 | 720 | 744 | 720 |
| Lease Payments | $ 10,884,000 | | | | | $ 907,000 | $ 907,000 | $ 907,000 | $ 907,000 | $ 907,000 | $ 907,000 | $ 907,000 | $ 907,000 | $ 907,000 | $ 907,000 | $ 907,000 | $ 907,000 |
| Pre-Lease Payments | $ - | | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Fixed Costs | $ 557,796 | $ - | $ - | $ 557,796 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Fuel Costs | $ 12,439,200 | | | | | $ 1,056,480 | $ 1,056,480 | $ 1,022,400 | $ 1,056,480 | $ 1,022,400 | $ 1,056,480 | $ 1,056,480 | $ 954,240 | $ 1,056,480 | $ 1,022,400 | $ 1,056,480 | $ 1,022,400 |
| Variable O&M (Estimate $9/MWh urea and $5 O&M) | $ 2,256,576 | | | | | $ 191,654 | $ 191,654 | $ 185,472 | $ 191,654 | $ 185,472 | $ 191,654 | $ 191,654 | $ 173,107 | $ 191,654 | $ 185,472 | $ 191,654 | $ 185,472 |
| Total Costs (Cash Flow) | $ 26,137,572 | | | $ 557,796 | | $ 2,155,134 | $ 2,155,134 | $ 2,114,872 | $ 2,155,134 | $ 2,114,872 | $ 2,155,134 | $ 2,155,134 | $ 2,034,347 | $ 2,155,134 | $ 2,114,872 | $ 2,155,134 | $ 2,114,872 |
| Total Generation @ 92% Load Factor | 161,184 | | | | | 13,689.60 | 13,689.60 | 13,248.00 | 13,689.60 | 13,248.00 | 13,689.60 | 13,689.60 | 12,364.80 | 13,689.60 | 13,248.00 | 13,689.60 | 13,248.00 |
| Total Revenue or Reduced Expense | $ 45,725,574 | | | | | $ 5,764,554 | $ 6,231,917 | $ 5,578,600 | $ 4,375,333 | $ 3,744,150 | $ 3,920,975 | $ 3,752,182 | $ 3,025,543 | $ 3,025,128 | $ 1,978,854 | $ 1,941,048 | $ 2,387,290 |
| Total Costs/MWh @ 92% Load Factor | | | | | | $ 157.43 | $ 157.43 | $ 159.64 | $ 157.43 | $ 159.64 | $ 157.43 | $ 157.43 | $ 164.53 | $ 157.43 | $ 159.64 | $ 157.43 | $ 159.64 |
| Operate for 1 Year | | | | | | | | | | | | | | | | | |
| Average Fixed & Lease Costs $/MWh | $ 70.99 | | | | | | | | | | | | | | | | |
| Average Variable Costs $/MWh | $ 91.17 | | | | | | | | | | | | | | | | |
| Average Total Costs $/MWh | $ 162.16 | | | | | | | | | | | | | | | | |
| Average Flat Forward Market $/MWh | $ 283.10 | | | | | $ 421.09 | $ 455.23 | $ 421.09 | $ 319.61 | $ 282.62 | $ 286.42 | $ 274.09 | $ 244.69 | $ 220.98 | $ 149.37 | $ 141.79 | $ 180.20 |
| Project Benefit - $/MWh | $ 120.94 | | | | | $ 263.66 | $ 297.80 | $ 261.45 | $ 162.18 | $ 122.98 | $ 128.99 | $ 116.66 | $ 80.16 | $ 63.55 | $ (10.27) | $ (15.64) | $ 20.56 |
| Project Benefit - Total Dollars (NET CASH FLOW) | $ 19,493,350 | | | $ (557,796) | | $ 3,609,419 | $ 4,076,782 | $ 3,463,728 | $ 2,220,199 | $ 1,629,278 | $ 1,765,841 | $ 1,597,048 | $ 991,196 | $ 869,993 | $ (136,018) | $ (214,086) | $ 272,418 |

**Support**

| | Totals | Mar-01 | Apr-01 | May-01 | Jun-01 | Jul-01 | Aug-01 | Sep-01 | Oct-01 | Nov-01 | Dec-01 | Jan-02 | Feb-02 | Mar-02 | Apr-02 | May-02 | Jun-02 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pre-Lease Costs | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Interest on Project Costs | | $ - | $ - | $ - | $ - | | | | | | | | | | | | |
| Fixed Costs | $ 557,796 | | $ - | $ 557,796 | $ - | $ - | $ - | $ - | $ - | | | | | | | | |
| Turbine | $ - | | $ - | $ - | $ - | | | | $ - | | | | | | | | |
| Siting | $ 120,000 | | $ - | $ 120,000 | $ | | | | | | | | | | | | |
| Interconnection | $ 385,000 | | | $ 385,000 | $ | $ - | $ - | $ - | | | | | | | | | |
| Construction | $ 11,000 | | | $ 11,000 | $ - | $ - | $ - | $ - | | | | | | | | | |
| Sales Tax (8.1% on everything - Max amount) | $ 41,796 | | $ - | $ 41,796 | $ - | $ - | $ - | $ - | $ - | | | | | | | | |

5/8 220,000

**Fuel Costs**

| | Jul-01 | Aug-01 | Sep-01 | Oct-01 | Nov-01 | Dec-01 | Jan-02 | Feb-02 | Mar-02 | Apr-02 | May-02 | Jun-02 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gallons/Hour | 1,420.00 | 1,420.00 | 1,420.00 | 1,420.00 | 1,420.00 | 1,420.00 | 1,420.00 | 1,420.00 | 1,420.00 | 1,420.00 | 1,420.00 | 1,420.00 |
| Total Gallons/Month | 1,056,480 | 1,056,480 | 1,022,400 | 1,056,480 | 1,022,400 | 1,056,480 | 1,056,480 | 954,240 | 1,056,480 | 1,022,400 | 1,056,480 | 1,022,400 |
| Diesel Cost/Gallon | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 |
| Fuel Cost | $1,056,480.00 | $1,056,480.00 | $1,022,400.00 | $1,056,480.00 | $1,022,400.00 | $1,056,480.00 | $1,056,480.00 | $954,240.00 | $1,056,480.00 | $1,022,400.00 | $1,056,480.00 | $1,022,400.00 |
| Cost of fuel/MMBtu | $ 7.20 | $ 7.20 | $ 7.20 | $ 7.20 | $ 7.20 | $ 7.20 | $ 7.20 | $ 7.20 | $ 7.20 | $ 7.20 | $ 7.20 | $ 7.20 |
| Total MMBtu Consumed per m | 146,639 | 146,639 | 141,909 | 146,639 | 141,909 | 146,639 | 146,639 | 132,449 | 146,639 | 141,909 | 146,639 | 141,909 |
| Heat Rate | 10,712 | 10,712 | 10,712 | 10,712 | 10,712 | 10,712 | 10,712 | 10,712 | 10,712 | 10,712 | 10,712 | 10,712 |
| Cost/MWh | $ 77.17 | $ 77.17 | $ 77.17 | $ 77.17 | $ 77.17 | $ 77.17 | $ 77.17 | $ 77.17 | $ 77.17 | $ 77.17 | $ 77.17 | $ 77.17 |

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## Avista Utilities
## Gas/Electric Transaction

Date of Transaction: 4/4/01 Reference No. ____________

Transaction Details: Purchase / Sale (Circle) (LEASE)

Delivery Period —

Volume 20 MW

Location DEVIL'S GAP

Price —

Broker —

Market Conditions: HIGH PRICES (Q3 Hr $485) IN THE FORWARD MARKET AND DAILY PRICES AROUND $300-$350.

System Position and Reason for Action (Attach Position Report): Flat to surplus in future months. Concerns about unit outages and load spikes in this high-priced market. Also critical water year conditions

Dispatchability: 100% Dispatchable - Able to respond to fluctuating loads (increases) and ~~to~~ resources (decreases/forced outages)

Transmission Alternatives: No firm ~~avails~~ available

Building Options: Analysis of alternative plants suggest this 12 month lease is favorable. This includes O+M and provides over $19 million of benefit over the year compared to the market.

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Financial and Rate Impacts: At current market prices, there is a $19 million benefit to customers. This generation provides customers protection from ~~prices~~ price volatility

Market Quotes: Broker ______ Quote ______

Broker ______ Quote ______

Broker ______ Quote ______

Completed by: [signature] Date: ______

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# Avista Utilities
## Position Report
## April 4, 2001

Indicates positions outside of risk policy limits

| Month | Hrs | Index Purchase (Sale) [a] Col (1) | Physical Position Long (Short) [b] Col (2) | Financial Put (Call) Net Delta [c] Col (3) | **Total Position Long (Short) [d]** Col (4) Col (2) + Col (3) | CT Inc in Phy Fuel Pur Col (5) | CT Turb. Fuel Not Pur [e] Col (6) | **Physical Open Position [f]** Col (7) Col (4) + Col (6) | **Financial Open Position [g]** Col (8) Col (7) - Col (1) | **Financial Quarter Average** Col (9) Avg Col 8 | **Fin & NG Open Position [h]** Col (10) Col (8) - Col (6) | Month Short Limit Col (11) | Month Long Limit Col (12) | **Fin & NG Quarter Average** Col (13) Avg Col 10 | Quarter Short Limit Col (14) | Quarter Long Limit Col (15) | Month | Hrs | Hrs | Impact of $50 Price Increase |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| May-01 | HL | (5) | 35 | 0 | **35** | 123 | 58 | **93** | **98** | | **40** | (25) | 125 | | | | May-01 | HL | 416 | $ 2,039,800 |
| May-01 | LL | (5) | 53 | 0 | **53** | 121 | 55 | **108** | **113** | | **58** | (25) | 125 | | | | May-01 | LL | 328 | $ 1,845,050 |
| Jun-01 | HL | (5) | 99 | 0 | **99** | 124 | 0 | **99** | **104** | | **104** | (25) | 125 | | | | Jun-01 | HL | 416 | $ 2,155,850 |
| Jun-01 | LL | (5) | 97 | 0 | **97** | 120 | 0 | **97** | **102** | | **102** | (25) | 125 | | | | Jun-01 | LL | 304 | $ 1,549,700 |
| Jul-01 | HL | (5) | (6) | 0 | **(6)** | 150 | 0 | **(6)** | **(1)** | | **(1)** | (75) | 200 | | | | Jul-01 | HL | 400 | $ (11,400) |
| Jul-01 | LL | (5) | 57 | 0 | **57** | 150 | 0 | **57** | **62** | | **62** | (75) | 200 | | | | Jul-01 | LL | 344 | $ 1,060,750 |
| Aug-01 | HL | 5 | (3) | 0 | **(3)** | 200 | 0 | **(3)** | **(8)** | **52** | **(8)** | (75) | 200 | **52** | (25) | 150 | Aug-01 | HL | 432 | $ (176,750) |
| Aug-01 | LL | 5 | 51 | 0 | **51** | 200 | 0 | **51** | **46** | **73** | **46** | (75) | 200 | **73** | (25) | 150 | Aug-01 | LL | 312 | $ 722,150 |
| Sep-01 | HL | (5) | 159 | 0 | **159** | 208 | 0 | **159** | **164** | | **164** | (75) | 200 | | | | Sep-01 | HL | 384 | $ 3,155,300 |
| Sep-01 | LL | (5) | 107 | 0 | **107** | 208 | 0 | **107** | **112** | | **112** | (75) | 200 | | | | Sep-01 | LL | 336 | $ 1,889,200 |
| Oct-01 | HL | (5) | 7 | 0 | **7** | 208 | 0 | **7** | **12** | | **12** | (150) | 250 | | | | Oct-01 | HL | 432 | $ 250,500 |
| Oct-01 | LL | (5) | 100 | 0 | **100** | 208 | 0 | **100** | **105** | | **105** | (150) | 250 | | | | Oct-01 | LL | 312 | $ 1,633,000 |
| Nov-01 | HL | (5) | 120 | 0 | **120** | 219 | 0 | **120** | **125** | **95** | **125** | (150) | 250 | **95** | (50) | 150 | Nov-01 | HL | 400 | $ 2,496,600 |
| Nov-01 | LL | (5) | 85 | (90) | **(5)** | 160 | 0 | **(5)** | **0** | **22** | **0** | (150) | 250 | **22** | (50) | 150 | Nov-01 | LL | 320 | $ 7,200 |
| Dec-01 | HL | (5) | 143 | 0 | **143** | 219 | 0 | **143** | **148** | | **148** | (150) | 250 | | | | Dec-01 | HL | 400 | $ 2,969,800 |
| Dec-01 | LL | (5) | 40 | (85) | **(46)** | 160 | 0 | **(46)** | **(41)** | | **(41)** | (150) | 250 | | | | Dec-01 | LL | 344 | $ (698,450) |
| Jan-02 | HL | (5) | 106 | 0 | **106** | 99 | 61 | **167** | **172** | | **111** | (150) | 250 | | | | Jan-02 | HL | 416 | $ 3,584,700 |
| Jan-02 | LL | (5) | 113 | (87) | **26** | 99 | 61 | **87** | **92** | | **31** | (150) | 250 | | | | Jan-02 | LL | 328 | $ 1,508,100 |
| Feb-02 | HL | (5) | 98 | 0 | **98** | 99 | 41 | **139** | **144** | **152** | **103** | (150) | 250 | **111** | (50) | 150 | Feb-02 | HL | 384 | $ 2,758,750 |
| Feb-02 | LL | (5) | 164 | (87) | **76** | 99 | 41 | **117** | **122** | **108** | **81** | (150) | 250 | **67** | (50) | 150 | Feb-02 | LL | 288 | $ 1,762,050 |
| Mar-02 | HL | (5) | 115 | 0 | **115** | 99 | 19 | **134** | **139** | | **120** | (150) | 250 | | | | Mar-02 | HL | 416 | $ 2,893,650 |
| Mar-02 | LL | (5) | 170 | (87) | **84** | 99 | 20 | **104** | **109** | | **89** | (150) | 250 | | | | Mar-02 | LL | 328 | $ 1,782,450 |
| Apr-02 | HL | (5) | 147 | (91) | **56** | 99 | 56 | **112** | **117** | | **61** | (150) | 250 | | | | Apr-02 | HL | 416 | $ 2,430,700 |
| Apr-02 | LL | (5) | 144 | (76) | **68** | 99 | 56 | **124** | **129** | | **73** | (150) | 250 | | | | Apr-02 | LL | 304 | $ 1,958,950 |
| May-02 | HL | (5) | 196 | 0 | **196** | 99 | 47 | **243** | **248** | **187** | **201** | (150) | 250 | **153** | (50) | 150 | May-02 | HL | 416 | $ 5,167,200 |
| May-02 | LL | (5) | 173 | 0 | **173** | 99 | 44 | **217** | **222** | **188** | **178** | (150) | 250 | **155** | (50) | 150 | May-02 | LL | 328 | $ 3,643,150 |
| Jun-02 | HL | (5) | 289 | (97) | **192** | 119 | 0 | **192** | **197** | | **197** | (150) | 250 | | | | Jun-02 | HL | 400 | $ 3,941,200 |
| Jun-02 | LL | (5) | 293 | (83) | **209** | 119 | 0 | **209** | **214** | | **214** | (150) | 250 | | | | Jun-02 | LL | 320 | $ 3,431,650 |
| Jul-02 | HL | (5) | 242 | 0 | **242** | 150 | 0 | **242** | **247** | | **247** | (175) | 250 | | | | Jul-02 | HL | 416 | $ 5,127,400 |
| Jul-02 | LL | (5) | 214 | 0 | **214** | 150 | 0 | **214** | **219** | | **219** | (175) | 250 | | | | Jul-02 | LL | 328 | $ 3,591,800 |
| | | | | | | | | | | | | | | | | | Jan-00 | 0 | | |
| Aug-02 | HL | 5 | (52) | 0 | **(52)** | 260 | 200 | **148** | **143** | **189** | **(57)** | (175) | 250 | **53** | (75) | 150 | Aug-02 | HL | 432 | $ 3,099,450 |
| Aug-02 | LL | 5 | 245 | 0 | **245** | 260 | 200 | **445** | **440** | **377** | **240** | (175) | 250 | **241** | (75) | 150 | Aug-02 | LL | 312 | $ 6,856,750 |
| Sep-02 | HL | (5) | (37) | 0 | **(37)** | 265 | 208 | **171** | **176** | | **(32)** | (175) | 250 | | | | Sep-02 | HL | 384 | $ 3,374,350 |
| Sep-02 | LL | (5) | 260 | 0 | **260** | 265 | 208 | **468** | **473** | | **265** | (175) | 250 | | | | Sep-02 | LL | 336 | $ 7,946,250 |
| Oct-02 | HL | (5) | 87 | 0 | **87** | 265 | 208 | **295** | **300** | | **92** | (175) | 250 | | | | Oct-02 | HL | 432 | $ 6,478,550 |
| Oct-02 | LL | (5) | 264 | 0 | **264** | 265 | 208 | **472** | **477** | | **269** | (175) | 250 | | | | Oct-02 | LL | 312 | $ 7,437,100 |

Footnotes: [a] Index transactions are already included in the total physical position. [b] Physical position. [c] Aggregate physical equivalent (delta) position of options (put and calls). [d] Total position is the combined physical and delta positions. [e] Turbines in this column are available for use, but gas has not been purchased. When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column. [f] Open physical position includes total position and available turbines. [g] Open financial position includes open physical position less any index position. [h] Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased.

AVISTA Corporation

*Energy Resources*

**Othello LM2500 Proposal**
Prepared by Jason Thackston
3/26/01

## Situation

Although the company has worked hard to balance the utility's load and resource positions, there are conditions that require additional short-term supplies of power. It is prudent for us to protect ourselves from short-term deficiencies, variability in available power form hydro projects, variability in loads, and generation unit outage risk given the high prices and volatility evident in the competitive electric power market. Building additional generation suitable for economic short-term supply is one such way to obtain that protection. The Spokane Industrial Park generation, if completed as planned, will add 50.7 megawatts of capacity by early July.

## Othello Generation

We have received a proposal for 23 megawatts of generation that would fit well inOthello. The generation is a new GE LM2500 turbine. The Othello site once contained a thirty megawatt diesel turbine that was sold nearly ten years ago. The LM2500 would be purchased to run on diesel, rather than natural gas, for two reasons: Sufficient natural gas is not available in the region, and there are two diesel storage tanks on the site from the previous turbine installation with a total capacity of over 500,000 gallons. The unit could be easily retrofitted with a natural gas or dual-fuel combustion system if it were relocated. Other issues include:

- **Alternatives to Project** – Avista continues to assess short-term supply through other temporary generation, customer load buy-backs, market purchases, and financial options. The economic analysis for the short-term compares the benefits of the project to the most liquid and available alternative, the over-the-counter energy market. Financial options are unavailable in the marketplace due to the dramatically increased volatility in the market and are not a viable alternative.
- **Air Permit** – This generation will be equipped with emissions controls that allow the standard permitting process to occur. The process will be completed well before operation of the unit, and the result is a permanent air permit.
- **Property** – Avista still owns the property, and the LM2500 will fit on the existing foundations with minimal modifications.
- **Electrical Interconnection** – 23 megawatts can easily be integrated into theOthello system with a transformer that is available for purchase.
- **Diesel Supply** – Avista has received a quote for diesel delivered toOthello – fuel is readily available and could be procured for a period of time.
- **Financing** – Total cost of this project is anticipated to be $17.6 million before taxes. This project could be wholly or partially self-financed. GE Capital has offered a capital lease on $11 million of the project. GE Capital has offered a similar lease package on the Spokane Industrial Park generation, so there may be issues with GE financing multiple Avista

projects. Due to that risk, I have assumed in the modeling that Avista would finance the entire project.

- **Reliability** – This is a new LM2500 turbine unit with new controls and re-manufactured electrical equipment.
- **Efficiency** – Due to the need to convert the turbine from natural gas to diesel, efficiency of the plant is not as high as natural gas. The heat rate is calculated to be 11,046.
- **Economics** – Because this generation would be used to protect against unit outages and peaking loads, the output of this generation would not be pre-sold into the market. However, on a short-term basis, as loads and resources permit, the generation could be sold into the market when economics support the transaction. Doing so would be prudent as it reduces the electric deferral balance.

The following information is based on forward market prices for both diesel and electricity as of this last week. Two scenarios have been prepared for the analysis. Scenario 1 assumes the generation is operational for a two-year period. Scenario 2 assumes the generation is operational for twelve months. Both scenarios assume capital costs are recovered over the operational period. Results of the analysis are summarized below and detailed in Attachment A:

| | **Operate 2 Years (370,723 MWh)** | | **Operate 1 Year (185,362 MWh)** | |
|---|---|---|---|---|
| | **$/MWh** | **Total Dollars** | **$/MWh** | **Total Dollars** |
| Fixed Cost to Generate | $ 51.33 | $ 19.0 million | $ 102.67 | $ 19.0 million |
| Variable Cost to Generate | 84.64 | 31.4 million | 84.64 | 15.7 million |
| Total Cost to Generate | 135.98 | 50.4 million | 187.31 | 34.7 million |
| Increased Revenue or Decreased Expense | 169.21 | 62.7 million | 229.08 | 42.4 million |
| Project Benefit | $ 33.23 | $ 12.3 Million | $ 41.77 | $ 7.7 Million |

In addition to the cash flow analysis, a revenue requirement analysis was completed. The net project benefit from a revenue requirement perspective is negative $236 thousand over a 25- year operational period. However, the project benefit over the first seventeen months is positive approximately $24 million. The Revenue Requirement Model can be found in Attachment B.

This project is beneficial to the system over the first two years and is considered a strong alternative to other short-term energy sources. The benefits of the project beyond 2002 are impacted significantly by the efficiency level caused by the diesel fuel source. Due to the short project payback of about six months, Avista is able to evaluate at a later time options beyond 2002. These options include, but are not limited to, keeping the unit at the site for peaking availability, relocating the unit to a site with access to natural gas, orselling the unit. A decision to keep the unit would be folded into the larger evaluation of long-term peaking generation needs, and a separate economic analysis would be conducted.

The analysis of this project assumes an operational date of September 1, but there is a high likelihood that the generation would be available in August. The economic viability of the plant would be positively impacted should that occur.

Jason Thackston
March 26, 2001

CONFIDENTIAL

**Cash Flow Ana'**
**23MW LM2500 L. ɜl Turbine**
**Attachment A**

Capacity 23.0 MW
Heat Rate 11,046

| | Totals | Apr-01 | May-01 | Jun-01 | Jul-01 | Aug-01 | Sep-01 | Oct-01 | Nov-01 | Dec-01 | Jan-02 | Feb-02 | Mar-02 | Apr-02 | May-02 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fixed Costs | $19,031,005 | $ 1,638,796 | $ 3,732,693 | $ 4,887,201 | $ 4,887,201 | $ 3,027,881 | $ 340,515 | $ 516,718 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Fuel Costs | $29,525,011 | $ - | $ - | $ - | $ - | $ - | $1,213,357 | $1,253,802 | $1,213,357 | $1,253,802 | $1,253,802 | $1,132,466 | $1,253,802 | $1,213,357 | $1,253,802 |
| Variable O&M (Estimate $5/MWh) | $ 1,853,616 | $ - | $ - | $ - | $ - | $ - | $ 76,176 | $ 78,715 | $ 76,176 | $ 78,715 | $ 78,715 | $ 71,098 | $ 78,715 | $ 76,176 | $ 78,715 |
| Total Costs (Cash Flow) | $50,409,632 | $ 1,638,796 | $ 3,732,693 | $ 4,887,201 | $ 4,887,201 | $ 3,027,881 | $1,630,048 | $1,849,235 | $1,289,533 | $1,332,517 | $1,332,517 | $1,203,564 | $1,332,517 | $1,289,533 | $1,332,517 |
| | | | | | | | | | | | | | | | |
| Total Generation @ 92% Load Factor | 370,723 | | | | | | 15,235.20 | 15,743.04 | 15,235.20 | 15,743.04 | 15,743.04 | 14,219.52 | 15,743.04 | 15,235.20 | 15,743.04 |
| Total Revenue or Reduced Expense | $62,714,177 | | | | | | $5,956,963 | $5,069,259 | $4,326,797 | $4,581,225 | $3,967,246 | $3,199,392 | $3,117,122 | $2,041,517 | $2,030,852 |
| | | | | | | | | | | | | | | | |
| Scenario 1 - Operate for 2 Years | | | | | | | | | | | | | | | |
| Average Fixed Costs $/MWh | $ 51.33 | $ 1,638,796 | $ 3,732,693 | $ 4,887,201 | $ 4,887,201 | $ 3,027,881 | $ 340,515 | $ 516,718 | | | | | | | |
| Average Variable Costs $/MWh | $ 84.64 | | | | | | $1,289,533 | $1,332,517 | $1,289,533 | $1,332,517 | $1,332,517 | $1,203,564 | $1,332,517 | $1,289,533 | $1,332,517 |
| Average Total Costs $/MWh | $ 135.98 | $ 1,638,796 | $ 3,732,693 | $ 4,887,201 | $ 4,887,201 | $ 3,027,881 | $1,630,048 | $1,849,235 | $1,289,533 | $1,332,517 | $1,332,517 | $1,203,564 | $1,332,517 | $1,289,533 | $1,332,517 |
| Average Flat Forward Market $/MWh | $ 169.21 | | | | | | $ 391.00 | $ 322.00 | $ 284.00 | $ 291.00 | $ 252.00 | $ 225.00 | $ 198.00 | $ 134.00 | $ 129.00 |
| Project Benefit - $/MWh | $ 33.23 | | | | | | $ 284.01 | $ 204.54 | $ 199.36 | $ 206.36 | $ 167.36 | $ 140.36 | $ 113.36 | $ 49.36 | $ 44.36 |
| Project Benefit - Total Dollars (NET CASH FLOW) | $12,319,823 | $(1,638,796) | $ (3,732,693) | $(4,887,201) | $(4,887,201) | $(3,027,881) | $4,326,916 | $3,220,024 | $3,037,264 | $3,248,708 | $2,634,729 | $1,995,828 | $1,784,605 | $ 751,984 | $ 698,335 |
| | | | | | | | | | | | | | | | |
| Scenario 2 - Operate for 1 Year | | | | | | | | | | | | | | | |
| Average Fixed Costs $/MWh | $ 102.67 | $ 1,638,796 | $ 3,732,693 | $ 4,887,201 | $ 4,887,201 | $ 3,027,881 | $ 340,515 | $ 516,718 | | | | | | | |
| Average Variable Costs $/MWh | $ 84.64 | | | | | | $1,289,533 | $1,332,517 | $1,289,533 | $1,332,517 | $1,332,517 | $1,203,564 | $1,332,517 | $1,289,533 | $1,332,517 |
| 1 Year Allocated Costs $/MWh | $ 187.31 | $ 1,638,796 | $ 3,732,693 | $ 4,887,201 | $ 4,887,201 | $ 3,027,881 | $1,630,048 | $1,849,235 | $1,289,533 | $1,332,517 | $1,332,517 | $1,203,564 | $1,332,517 | $1,289,533 | $1,332,517 |
| 1 Year Flat Forward Market $/MWh | $ 229.08 | | | | | | $ 391.00 | $ 322.00 | $ 284.00 | $ 291.00 | $ 252.00 | $ 225.00 | $ 198.00 | $ 134.00 | $ 129.00 |
| 1 Year Project Benefit - $/MWh | $ 41.77 | | | | | | $ 284.01 | $ 204.54 | $ 199.36 | $ 206.36 | $ 167.36 | $ 140.36 | $ 113.36 | $ 49.36 | $ 44.36 |
| 1 Year Project Benefit - Total Dollars | $ 7,742,935 | $(1,638,796) | $ (3,732,693) | $(4,887,201) | $(4,887,201) | $(3,027,881) | $4,326,916 | $3,220,024 | $3,037,264 | $3,248,708 | $2,634,729 | $1,995,828 | $1,784,605 | $ 751,984 | $ 698,335 |

CONFIDENTIAL

Cash Flow Ana
23MW LM2500 L. .el Turbine
Attachment A

Capacity
Heat Rate

| | Jun-02 | Jul-02 | Aug-02 | Sep-02 | Oct-02 | Nov-02 | Dec-02 | Jan-03 | Feb-03 | Mar-03 | Apr-03 | May-03 | Jun-03 | Jul-03 | Aug-03 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fixed Costs | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Fuel Costs | $1,213,357 | $1,253,802 | $1,253,802 | $1,213,357 | $1,253,802 | $1,213,357 | $1,253,802 | $1,253,802 | $1,132,466 | $1,253,802 | $1,213,357 | $1,253,802 | $1,213,357 | $1,253,802 | $1,253,802 |
| Variable O&M (Estimate $5/MWh) | $ 76,176 | $ 78,715 | $ 78,715 | $ 76,176 | $ 78,715 | $ 76,176 | $ 78,715 | $ 78,715 | $ 71,098 | $ 78,715 | $ 76,176 | $ 78,715 | $ 76,176 | $ 78,715 | $ 78,715 |
| Total Costs (Cash Flow) | $1,289,533 | $1,332,517 | $1,332,517 | $1,289,533 | $1,332,517 | $1,289,533 | $1,332,517 | $1,332,517 | $1,203,564 | $1,332,517 | $1,289,533 | $1,332,517 | $1,289,533 | $1,332,517 | $1,332,517 |
| | | | | | | | | | | | | | | | |
| Total Generation @ 92% Load Factor | 15,235.20 | 15,743.04 | 15,743.04 | 15,235.20 | 15,743.04 | 15,235.20 | 15,743.04 | 15,743.04 | 14,219.52 | 15,743.04 | 15,235.20 | 15,743.04 | 15,235.20 | 15,743.04 | 15,743.04 |
| Total Revenue or Reduced Expense | $2,117,693 | $3,054,150 | $2,991,178 | $2,681,395 | $2,282,741 | $1,950,106 | $2,062,338 | $1,983,623 | $1,592,586 | $1,558,561 | $1,020,758 | $1,023,298 | $1,051,229 | $1,527,075 | $1,527,075 |
| | | | | | | | | | | | | | | | |
| Scenario 1 - Operate for 2 Years | | | | | | | | | | | | | | | |
| Average Fixed Costs $/MWh | | | | | | | | | | | | | | | |
| Average Variable Costs $/MWh | $1,289,533 | $1,332,517 | $1,332,517 | $1,289,533 | $1,332,517 | $1,289,533 | $1,332,517 | $1,332,517 | $1,203,564 | $1,332,517 | $1,289,533 | $1,332,517 | $1,289,533 | $1,332,517 | $1,332,517 |
| Average Total Costs $/MWh | $1,289,533 | $1,332,517 | $1,332,517 | $1,289,533 | $1,332,517 | $1,289,533 | $1,332,517 | $1,332,517 | $1,203,564 | $1,332,517 | $1,289,533 | $1,332,517 | $1,289,533 | $1,332,517 | $1,332,517 |
| Average Flat Forward Market $/MWh | $ 139.00 | $ 194.00 | $ 190.00 | $ 176.00 | $ 145.00 | $ 128.00 | $ 131.00 | $ 126.00 | $ 112.00 | $ 99.00 | $ 67.00 | $ 65.00 | $ 69.00 | $ 97.00 | $ 97.00 |
| Project Benefit - $/MWh | $ 54.36 | $ 109.36 | $ 105.36 | $ 91.36 | $ 60.36 | $ 43.36 | $ 46.36 | $ 41.36 | $ 27.36 | $ 14.36 | $ (17.64) | $ (19.64) | $ (15.64) | $ 12.36 | $ 12.36 |
| Project Benefit - Total Dollars (NET CASH FLOW) | $ 828,160 | $1,721,633 | $1,658,661 | $1,391,863 | $ 950,224 | $ 660,573 | $ 729,821 | $ 651,106 | $ 389,022 | $ 226,044 | $ (268,774) | $ (309,219) | $ (238,304) | $ 194,558 | $ 194,558 |
| | | | | | | | | | | | | | | | |
| Scenario 2 - Operate for 1 Year | | | | | | | | | | | | | | | |
| Average Fixed Costs $/MWh | | | | | | | | | | | | | | | |
| Average Variable Costs $/MWh | $1,289,533 | $1,332,517 | $1,332,517 | | | | | | | | | | | | |
| 1 Year Allocated Costs $/MWh | $1,289,533 | $1,332,517 | $1,332,517 | | | | | | | | | | | | |
| 1 Year Flat Forward Market $/MWh | $ 139.00 | $ 194.00 | $ 190.00 | | | | | | | | | | | | |
| 1 Year Project Benefit - $/MWh | $ 54.36 | $ 109.36 | $ 105.36 | | | | | | | | | | | | |
| 1 Year Project Benefit - Total Dollars | $ 828,160 | $1,721,633 | $1,658,661 | | | | | | | | | | | | |

# 1 - LM 2500 SCCT Installation -- One Diesel Machine at Othello -- Online in Sept 2001 -- No Fuel Escalation

Avista Corporation

Economic Analysis Detail - Attachment B

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### Assumptions

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Installed Cost | 19,031 | $000s | Fixed Charge | 0.00 | per kW-month | Variable O&M | 0.67 | 2001$/MWh | Electric Wheeling Losses | 0.0 percent |
| Project Capacity | 23.0 | MW | Fixed O&M | 1.81 | 2003$ per kW-month | | | | | |
| Heat Rate | 11,046 | Btu/kWh | Escalation Rates | | | Insurance Cost | 0.0 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.77 percent |
| Peak Gas Useage | 6,097 | 000s dth | Fixed O&M | 2.5 | percent | Gas Transport | 0.00 | 2000 $/dth | Real Discount Rate | 5.1 percent |
| | | | Variable O&M | 2.5 | percent | Electric Wheeling | 0 | $/MW-month thru 2006 | | |
| | | | Transportation | 2.0 | percent | General Inflation | 2.5 | percent | | |

| | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Fixed Costs – Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 64.2 | 247 | 0 | 247 | 3.8 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 |
| 2 | 2002 | 182.6 | 3,757 | 0 | 3,757 | 20.6 | 488 | 0 | 0 | 259 | 0 | 747 | 4.1 |
| 3 | 2003 | 130.8 | 3,460 | 0 | 3,460 | 26.5 | 500 | 0 | 0 | 250 | 0 | 750 | 5.7 |
| 4 | 2004 | 58.2 | 3,071 | 0 | 3,071 | 52.8 | 512 | 0 | 0 | 241 | 0 | 754 | 13.0 |
| 5 | 2005 | 28.9 | 2,852 | 0 | 2,852 | 98.8 | 525 | 0 | 0 | 233 | 0 | 758 | 26.3 |
| 6 | 2006 | 7.9 | 2,670 | 0 | 2,670 | 338.4 | 538 | 0 | 0 | 224 | 0 | 762 | 96.6 |
| 7 | 2007 | 3.0 | 2,554 | 0 | 2,554 | 848.4 | 552 | 0 | 0 | 215 | 0 | 766 | 254.6 |
| 8 | 2008 | 18.0 | 2,517 | 0 | 2,517 | 139.9 | 566 | 0 | 0 | 206 | 0 | 771 | 42.9 |
| 9 | 2009 | 17.3 | 2,424 | 0 | 2,424 | 139.8 | 580 | 0 | 0 | 197 | 0 | 776 | 44.8 |
| 10 | 2010 | 15.3 | 2,326 | 0 | 2,326 | 152.5 | 594 | 0 | 0 | 188 | 0 | 782 | 51.3 |
| 11 | 2011 | 17.9 | 2,247 | 0 | 2,247 | 125.9 | 609 | 0 | 0 | 179 | 0 | 788 | 44.1 |
| 12 | 2012 | 27.5 | 2,195 | 0 | 2,195 | 79.9 | 624 | 0 | 0 | 170 | 0 | 794 | 28.9 |
| 13 | 2013 | 20.4 | 2,079 | 0 | 2,079 | 102.0 | 640 | 0 | 0 | 161 | 0 | 801 | 39.3 |
| 14 | 2014 | 24.1 | 2,005 | 0 | 2,005 | 83.2 | 656 | 0 | 0 | 152 | 0 | 808 | 33.5 |
| 15 | 2015 | 22.5 | 1,909 | 0 | 1,909 | 85.0 | 672 | 0 | 0 | 143 | 0 | 815 | 36.3 |
| 16 | 2016 | 24.2 | 1,827 | 0 | 1,827 | 75.4 | 689 | 0 | 0 | 134 | 0 | 823 | 34.0 |
| 17 | 2017 | 26.1 | 1,745 | 0 | 1,745 | 66.9 | 706 | 0 | 0 | 125 | 0 | 831 | 31.9 |
| 18 | 2018 | 27.6 | 1,662 | 0 | 1,662 | 60.3 | 724 | 0 | 0 | 116 | 0 | 840 | 30.5 |
| 19 | 2019 | 30.5 | 1,586 | 0 | 1,586 | 51.9 | 742 | 0 | 0 | 107 | 0 | 849 | 27.8 |
| 20 | 2020 | 45.0 | 1,552 | 0 | 1,552 | 34.5 | 761 | 0 | 0 | 98 | 0 | 859 | 19.1 |
| 21 | 2021 | 47.0 | 1,471 | 0 | 1,471 | 31.3 | 780 | 0 | 0 | 89 | 0 | 869 | 18.5 |
| 22 | 2022 | 49.0 | 1,399 | 0 | 1,399 | 28.6 | 799 | 0 | 0 | 80 | 0 | 880 | 18.0 |
| 23 | 2023 | 53.1 | 1,354 | 0 | 1,354 | 25.5 | 819 | 0 | 0 | 72 | 0 | 891 | 16.8 |
| 24 | 2024 | 56.0 | 1,293 | 0 | 1,293 | 23.1 | 420 | 0 | 0 | 63 | 0 | 482 | 8.6 |
| 25 | 2025 | 58.2 | 1,250 | 0 | 1,250 | 21.5 | 430 | 0 | 0 | 54 | 0 | 484 | 8.3 |
| 2001$ | | | | | | | | | | | | | |
| Net Present Value | | | 24,822 | 0 | 24,822 | | 5,873 | 0 | 0 | 1,862 | 0 | 7,735 | |
| Nominal Levelized Cost ($/MWh) | | | | | | 54.0 | | | | | | | 16.8 |
| Real Levelized Cost ($/MWh) | | | | | | 42.3 | | | | | | | 13.2 |

| | Year | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 247 | 247 | 3.8 | 14,154 | 13,907 | 216.8 | 5,109 | 43 | 5,152 | 80.3 | 5,398 | 84.2 |
| 2 | 2002 | 4,504 | 4,504 | 24.7 | 14,592 | 10,088 | 55.2 | 14,546 | 122 | 14,668 | 80.3 | 19,172 | 105.0 |
| 3 | 2003 | 4,210 | 4,210 | 32.2 | 3,090 | (1,120) | (8.6) | 10,415 | 88 | 10,503 | 80.3 | 14,713 | 112.5 |
| 4 | 2004 | 3,824 | 3,824 | 65.7 | 951 | (2,873) | (49.4) | 4,633 | 39 | 4,671 | 80.3 | 8,496 | 146.1 |
| 5 | 2005 | 3,610 | 3,610 | 125.1 | 389 | (3,221) | (111.6) | 2,299 | 19 | 2,318 | 80.3 | 5,928 | 205.4 |
| 6 | 2006 | 3,432 | 3,432 | 435.0 | 96 | (3,336) | (422.8) | 628 | 5 | 634 | 80.3 | 4,066 | 515.3 |
| 7 | 2007 | 3,320 | 3,320 | 1,103.0 | 24 | (3,296) | (1,095.1) | 240 | 2 | 242 | 80.4 | 3,562 | 1,183.4 |
| 8 | 2008 | 3,288 | 3,288 | 182.8 | 384 | (2,904) | (161.4) | 1,432 | 12 | 1,444 | 80.3 | 4,733 | 263.1 |
| 9 | 2009 | 3,200 | 3,200 | 184.5 | 398 | (2,802) | (161.6) | 1,381 | 12 | 1,393 | 80.3 | 4,593 | 264.9 |
| 10 | 2010 | 3,108 | 3,108 | 203.8 | 317 | (2,791) | (183.0) | 1,214 | 10 | 1,225 | 80.3 | 4,333 | 284.1 |
| 11 | 2011 | 3,035 | 3,035 | 170.0 | 332 | (2,703) | (151.4) | 1,421 | 12 | 1,433 | 80.3 | 4,469 | 250.3 |
| 12 | 2012 | 2,989 | 2,989 | 108.9 | 507 | (2,482) | (90.4) | 2,187 | 18 | 2,206 | 80.3 | 5,195 | 189.2 |
| 13 | 2013 | 2,880 | 2,880 | 141.3 | 331 | (2,549) | (125.0) | 1,623 | 14 | 1,637 | 80.3 | 4,517 | 221.6 |
| 14 | 2014 | 2,812 | 2,812 | 116.7 | 379 | (2,434) | (101.0) | 1,920 | 16 | 1,936 | 80.3 | 4,748 | 197.0 |
| 15 | 2015 | 2,725 | 2,725 | 121.4 | 391 | (2,333) | (103.9) | 1,788 | 15 | 1,803 | 80.3 | 4,527 | 201.7 |
| 16 | 2016 | 2,650 | 2,650 | 109.3 | 409 | (2,241) | (92.5) | 1,931 | 16 | 1,947 | 80.3 | 4,597 | 189.7 |
| 17 | 2017 | 2,577 | 2,577 | 98.8 | 423 | (2,154) | (82.6) | 2,077 | 17 | 2,095 | 80.3 | 4,672 | 179.1 |
| 18 | 2018 | 2,502 | 2,502 | 90.8 | 481 | (2,022) | (73.4) | 2,194 | 18 | 2,213 | 80.3 | 4,715 | 171.2 |
| 19 | 2019 | 2,434 | 2,434 | 79.8 | 530 | (1,904) | (62.4) | 2,431 | 20 | 2,451 | 80.3 | 4,885 | 160.1 |
| 20 | 2020 | 2,411 | 2,411 | 53.6 | 979 | (1,432) | (31.8) | 3,583 | 30 | 3,613 | 80.3 | 6,024 | 133.9 |
| 21 | 2021 | 2,340 | 2,340 | 49.8 | 1,067 | (1,273) | (27.1) | 3,740 | 31 | 3,772 | 80.3 | 6,112 | 130.1 |
| 22 | 2022 | 2,278 | 2,278 | 46.5 | 1,137 | (1,142) | (23.3) | 3,902 | 33 | 3,934 | 80.3 | 6,213 | 126.8 |
| 23 | 2023 | 2,245 | 2,245 | 42.3 | 1,221 | (1,024) | (19.3) | 4,230 | 36 | 4,265 | 80.3 | 6,510 | 122.6 |
| 24 | 2024 | 1,776 | 1,776 | 31.7 | 1,281 | (495) | (8.8) | 4,459 | 38 | 4,496 | 80.3 | 6,272 | 112.0 |
| 25 | 2025 | 1,734 | 1,734 | 29.8 | 1,426 | (307) | (5.3) | 4,634 | 39 | 4,673 | 80.3 | 6,407 | 110.1 |
| 2001$ | | | | | | | | | | | | | |
| Net Present Value | | 32,557 | 32,557 | | 32,321 | (236) | | 43,459 | 366 | 43,824 | | 76,381 | |
| Nominal Levelized Cost ($/MWh) | | | | 70.9 | | | (0.5) | | | | 95.4 | | 166.2 |
| Real Levelized Cost ($/MWh) | | | | 55.5 | | | (0.4) | | | | 74.7 | | 130.3 |

**CONFIDENTIAL**

# Avista Utilities
## Gas/Electric Transaction

Date of Transaction: 3/26/01 Reference No. —

Transaction Details: Purchase / Sale (Circle)

Delivery Period SEPTEMBER 1

Volume 23 MW

Location Othello CT

Price 17.6MM

Broker —

Market Conditions: FORWARD MARKET PRICES ARE $229. FLAT OVER 12 MONTHS AND $169 FLAT OVER ~~24~~ 24 MONTHS DAY-AHEAD PRICES ARE ABOVE $300.

System Position and Reason for Action (Attach Position Report): SEVERAL PERIODS OF DEFICIT WITHOUT FACTORING LOAD/SUPPLY VOLATILITY.

Dispatchability of Product: 100% DISPATCHABLE

Transmission Alternatives: N/A

Building Options: COMPARED TO OTHER ALTERNATIVES TO BUILD BY THIS SUMMER, THIS IS FAVORABLE

JRT 10/2/00

Financial and Rate Impacts: PROTECTS CUSTOMERS FROM SOME VOLATILITY - ADDS DIVERSITY OF FUEL SOURCES.

Market Quotes: Broker ______ Quote ______
Broker ______ Quote ______
Broker ______ Quote ______

LONGER-TERM PRODUCT - COMPARES TO OTHER GENERATION AND AVERAGE OF FORWARD MARKET PRICES

Completed by: JASON THACKSTON Date: ______

JRT 10/2/00

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**Avis⁴⁻ ᑊUtilities**

**Pos. Report**

**March 22, 2001**

CONFIDENTIAL: For Internal Use Only

Indicates positions outside of risk policy limits.

| Month & Hours | Index Purchase (Sale) [a] | Physical Position Long (Short) [b] | Financial Put (Call) Net Delta [c] | Total Position Long (Short) [d] | CT Inc in Phy Fuel Pur | CT Turb. Fuel Not Pur [e] | Physical Open Position [f] | Financial Open Position [g] | Financial Quarter Average | Fin & NG Open Position [h] | Month Short Limit | Month Long Limit | Fin & NG Quarter Average | Quarter Short Limit | Quarter Long Limit | Month & Hours | Hrs | Impact of $50 Price Increase |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | | | |
| Apr 01 HL | (5) | (8) | 0 | **(8)** | 212 | 0 | **(8)** | **(3)** | | **(3)** | (75) | 200 | | | | Apr 01 HL | 400 | $ (55,728) |
| Apr 01 LL | (5) | 54 | 0 | **54** | 212 | 0 | **54** | **59** | | **59** | (75) | 200 | | | | Apr 01 LL | 319 | $ 940,644 |
| May 01 HL | (5) | 18 | 0 | **18** | 128 | 58 | **76** | **81** | **27** | **23** | (75) | 200 | **8** | (25) | 150 | May 01 HL | 416 | $ 1,689,542 |
| May 01 LL | (5) | (20) | 0 | **(20)** | 126 | 55 | **35** | **40** | **13** | **(15)** | (75) | 200 | **(6)** | (25) | 150 | May 01 LL | 328 | $ 652,304 |
| Jun 01 HL | (5) | (1) | 0 | **(1)** | 122 | 0 | **(1)** | **4** | | **4** | (75) | 200 | | | | Jun 01 HL | 416 | $ 77,468 |
| Jun 01 LL | (5) | (66) | 0 | **(66)** | 122 | 0 | **(66)** | **(61)** | | **(61)** | (75) | 200 | | | | Jun 01 LL | 304 | $ (920,550) |
| Jul 01 HL | (5) | (42) | 0 | **(42)** | 150 | 0 | **(42)** | **(37)** | | **(37)** | (150) | 250 | | | | Jul 01 HL | 400 | $ (730,115) |
| Jul 01 LL | (5) | (23) | 0 | **(23)** | 150 | 0 | **(23)** | **(18)** | | **(18)** | (150) | 250 | | | | Jul 01 LL | 344 | $ (307,647) |
| Aug 01 HL | 5 | (65) | 0 | **(65)** | 200 | 0 | **(65)** | **(70)** | **(7)** | **(70)** | (150) | 250 | **(7)** | (50) | 150 | Aug 01 HL | 432 | $ (1,505,250) |
| Aug 01 LL | 5 | 34 | 0 | **34** | 200 | 0 | **34** | **29** | **40** | **29** | (150) | 250 | **40** | (50) | 150 | Aug 01 LL | 312 | $ 448,500 |
| Sep 01 HL | (5) | 79 | 0 | **79** | 205 | 0 | **79** | **84** | | **84** | (150) | 250 | | | | Sep 01 HL | 384 | $ 1,612,678 |
| Sep 01 LL | (5) | 103 | 0 | **103** | 205 | 0 | **103** | **108** | | **108** | (150) | 250 | | | | Sep 01 LL | 336 | $ 1,812,242 |
| Oct 01 HL | (5) | (47) | 0 | **(47)** | 212 | 0 | **(47)** | **(42)** | | **(42)** | (150) | 250 | | | | Oct 01 HL | 432 | $ (916,071) |
| Oct 01 LL | (5) | 82 | 0 | **82** | 212 | 0 | **82** | **87** | | **87** | (150) | 250 | | | | Oct 01 LL | 313 | $ 1,364,624 |
| Nov 01 HL | (5) | 39 | 0 | **39** | 219 | 0 | **39** | **44** | **19** | **44** | (150) | 250 | **19** | (50) | 150 | Nov 01 HL | 400 | $ 889,762 |
| Nov 01 LL | (5) | 40 | (88) | **(48)** | 160 | 0 | **(48)** | **(43)** | **(22)** | **(43)** | (150) | 250 | **(22)** | (50) | 150 | Nov 01 LL | 320 | $ (682,667) |
| Dec 01 HL | (5) | 51 | 0 | **51** | 219 | 0 | **51** | **56** | | **56** | (150) | 250 | | | | Dec 01 HL | 400 | $ 1,122,283 |
| Dec 01 LL | (5) | (32) | (84) | **(116)** | 160 | 0 | **(116)** | **(111)** | | **(111)** | (150) | 250 | | | | Dec 01 LL | 344 | $ (1,912,285) |
| Jan 02 HL | (5) | 37 | 0 | **37** | 99 | 61 | **98** | **103** | | **42** | (150) | 250 | | | | Jan 02 HL | 416 | $ 2,137,200 |
| Jan 02 LL | (5) | 51 | (85) | **(34)** | 99 | 61 | **27** | **32** | | **(29)** | (150) | 250 | | | | Jan 02 LL | 328 | $ 529,290 |
| Feb 02 HL | (5) | 37 | 0 | **37** | 99 | 41 | **78** | **83** | **92** | **42** | (150) | 250 | **52** | (50) | 150 | Feb 02 HL | 384 | $ 1,584,571 |
| Feb 02 LL | (5) | 122 | (84) | **38** | 99 | 41 | **79** | **84** | **60** | **43** | (150) | 250 | **20** | (50) | 150 | Feb 02 LL | 288 | $ 1,215,600 |
| Mar 02 HL | (5) | 67 | 0 | **67** | 99 | 19 | **86** | **91** | | **72** | (150) | 250 | | | | Mar 02 HL | 416 | $ 1,896,983 |
| Mar 02 LL | (5) | 121 | (82) | **39** | 99 | 20 | **59** | **64** | | **44** | (150) | 250 | | | | Mar 02 LL | 328 | $ 1,054,680 |
| Apr 02 HL | (5) | 130 | (96) | **34** | 99 | 56 | **90** | **95** | | **39** | (175) | 250 | | | | Apr 02 HL | 416 | $ 1,984,343 |
| Apr 02 LL | (5) | 84 | (73) | **11** | 99 | 56 | **67** | **72** | | **16** | (175) | 250 | | | | Apr 02 LL | 303 | $ 1,088,521 |
| May 02 HL | (5) | 224 | 0 | **224** | 99 | 47 | **271** | **276** | **168** | **229** | (175) | 250 | **134** | (75) | 150 | May 02 HL | 416 | $ 5,748,792 |
| May 02 LL | (5) | 173 | 0 | **173** | 99 | 44 | **217** | **222** | **144** | **178** | (175) | 250 | **111** | (75) | 150 | May 02 LL | 328 | $ 3,641,204 |
| Jun 02 HL | (5) | 219 | (90) | **129** | 119 | 0 | **129** | **134** | | **134** | (175) | 250 | | | | Jun 02 HL | 400 | $ 2,673,864 |
| Jun 02 LL | (5) | 210 | (77) | **133** | 119 | 0 | **133** | **138** | | **138** | (175) | 250 | | | | Jun 02 LL | 320 | $ 2,211,000 |
| Jul 02 HL | (5) | 221 | 0 | **221** | 150 | 0 | **221** | **226** | | **226** | (175) | 250 | | | | Jul 02 HL | 416 | $ 4,693,531 |
| Jul 02 LL | (5) | 112 | 0 | **112** | 150 | 0 | **112** | **117** | | **117** | (175) | 250 | | | | Jul 02 LL | 328 | $ 1,918,612 |
| Aug 02 HL | 5 | (112) | 0 | **(112)** | 260 | 200 | **88** | **83** | **143** | **(117)** | (175) | 250 | **8** | (75) | 150 | Aug 02 HL | 432 | $ 1,795,500 |
| Aug 02 LL | 5 | 212 | 0 | **212** | 260 | 200 | **412** | **407** | **331** | **207** | (175) | 250 | **196** | (75) | 150 | Aug 02 LL | 312 | $ 6,353,100 |
| Sep 02 HL | (5) | (89) | 0 | **(89)** | 265 | 205 | **116** | **121** | | **(84)** | (175) | 250 | | | | Sep 02 HL | 384 | $ 2,332,678 |
| Sep 02 LL | (5) | 259 | 0 | **259** | 265 | 205 | **464** | **469** | | **264** | (175) | 250 | | | | Sep 02 LL | 336 | $ 7,885,442 |

Footnotes: [a] Index transactions are already included in the total physical position. [b] Physical position. [c] Aggregate physical equivalent (delta) position of options (put and calls). [d] Total position is the combined physical and delta positions. [e] Turbines in this column are available for use, but gas has not been purchased. When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column. [f] Open physical position includes total position and available turbines. [g] Open financial position includes open physical position less any index position. [h] Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-C20)

CONFIDENTIAL

# Small Generation - Rejected Projects



| | Project | Total MW | Type | Total Cost or Lease (millions) | NPV (millions) | Power Cost ($/MWh) | Fixed/Variable Operating Cost ($/MWh) | Time-Line | Notes |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Boulder Park Rejected | 18.4 | 8-Cooper Superior 2.3MW natural gas units (used – located in England) | $14.6 | (not available yet) | $71 (over 5 yr operation) $168 (over 1 yr operation) | $19/$52 (over 5 years) $103/$65 (Over 1 year) | 7/13 – target on-line date (with air freight) 7/27 target on-line date (w/o air freight) | Vender sold units to a third party. |
| 2 | Boulder Park Rejected | 32.2 | 17-Jenbaucher 1.9MW natural gas units (new – located in England) | Part of Cooper Project | Part of Cooper Project | Part of Cooper Project | Part of Cooper Project | Part of Cooper Project | Controls did not fit US standards and were unsuitable. |
| 3 | Rejected | 25 | 25 – 1MW natural gas containerized reciprocating units owned by Maxim Power Corp (Canadian firm). 2 year min. lease only. | $17.18 | $25.7 | $103 | $43/$60 | 9/1 – target installation (units are delivered over a time period 6/15 through 8/15) | Too many unknowns. Also, concern for availability and delivery. No site identified. Many estimates regarding installation costs. Maintenance cost is unknown. Party will not sell units. 2-year lease in the minimum option. Avista would have to provide step-up transformers from 600 volts. (Transformer lead time may not allow for summer installation.) |

# Small Generation – Rejected Projects

August 24, 2001

| | Project | Total MW | Type | Total Cost or Lease (millions) | NPV (millions) | Power Cost ($/MWh) | Fixed/Variable Operating Cost ($/MWh) | Time-Line | Notes |
|---|---|---|---|---|---|---|---|---|---|
| 4 | Rejected | 44 | 20 - 2.25MW bi-fuel (oil/natural gas) units. Genertek International. GM locomotive engine. | $24.68 million | | | | Approximately 90days. | No site identified. Emission data arrived late. Too many other projects in the air quality modeling queue to start on this project. Generally indicate a $440/kw cost without emission controls. Can provide step up transformer to 13.8KV. |
| 5 | Rejected | 17 | 20 – 850KW Guascor natural gas units. The Power Company is the representative in Seattle area. | $9.4 for 12 month lease. | $16.9 | $145 | $72/$72 | | No site identified suitable for these units. Economics based on rough estimates. |
| 6 | Rejected | 12 | 16 – 1.5MW bi-fuel (oil/natural gas) Simpower units. The Power Company is the representative in Seattle area. | $3.7 for 12 month lease | $9.3 | $176 | $42/$133 | | No site identified suitable for these units. Economics based on rough and preliminary estimates. |
| 7 | Rejected | 10- 20 | GE Rentals | | | | | | No proposal made. No data on emissions. (100% diesel) |
| 8 | Rejected | 25 | 1 – 25MW Rolls Royce engine. Owned by Monsanto and other partners | | | 270 | | Sept. on-line target | See memo "Coyote Springs (Port of Morrow) Site Analysis for Peaking Generation" dated 2-26-01. |

# Small Generation - Rejected Projects

August 24, 2001

| | Project | Total MW | Type | Total Cost or Lease (millions) | NPV (millions) | Power Cost ($/MWh) | Fixed/Variable Operating Cost ($/MWh) | Time-Line | Notes |
|---|---|---|---|---|---|---|---|---|---|
| 9 | Rejected | 18 | 12 – 1.5 MW reconditioned diesel units. | Avista only provides site and electric connection and scheduling. | | Est. $250 for Q3. | Est. $250 for Q3. | | Units would be third party owned. Installation for this summer only. Offer is to split net margins with Avista. Rejected in that cost would be higher than other alternatives. |
| 10 | Rejected | 30 | 1-FT8-1 Power Pac w/o SCR, Oil unit | $9.0 + install costs & SCR | | | | July 1 – possible install date | Unit is located Chili. 3500 hours of operation on unit. Requires complete overhaul @ 8000 hours. Rejected due to impending major maintenance and concern over maintenance received |
| 11 | Rejected | 30 | 1 – Brown Boveri gas turbine unit | $10 + installation and SCR | | | | | Located in Mexico. 100,000 of operation on the unit. Rejected due to operational risks of such a used unit. |
| 12 | Rejected | 20 | 2 – GE gas turbines. | | | | | | 1964 unit. Was sold to another party. |
| 13 | Rejected | Various | Cummins Diesel | | | | | | No units available until Q1 2002. |
| 14 | Rejected | Various | Cat – Western States Machinery | | | | | | All diesel units with no emission controls and therefore not able to permit for continuous operation. |
| 15 | Rejected | | Solar Turbines – Peterson Power | | | | | | No units available until September or later if SCR and Catalyst are required. |
| 16 | Rejected | | Jenbacher | | | | | | No new units available until Q1 2002. |
| 17 | Rejected | | United Rentals - diesel | | | | | | No site. Emission controls? |

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## Small Generation - Rejected Projects

August 24, 2001

| | Project | Total MW | Type | Total Cost or Lease (millions) | NPV (millions) | Power Cost ($/MWh) | Fixed/Variable Operating Cost ($/MWh) | Time-Line | Notes |
|---|---|---|---|---|---|---|---|---|---|
| 18 | Rejected | 6.6 | Rolls Royce -gas | | | | | | Vendor proposal is to place these at FAFB. FAFB is not Avista's load. Requires BPA transmission at extra cost. |
| 19 | Rejected | 18MW | Cummins - diesel | $5 million | | | | | No site. No emissions data. Delivery beyond summer period. |
| | [redacted] | | | | | | | | |

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-C21)

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**Avista Corp.**
**Small Generation Analysis**
**June 19, 2001**

| Project | Capacity | Terms | Operational | Total Project Costs (Capital & Lease) | Estimated Fixed/MWh | Estimated Variable/MWh*** | Original Project Benefit: Date Calculated | Original Project Benefit: Dollar Benefit | 6/4/01 Value | 6/11/01 Value |
|---|---|---|---|---|---|---|---|---|---|---|
| Devil's Gap | 20MW | Leased 12 Months | 07-01-01 | $11.7mm | $ 73.00 | $ 90.00 | 04-04-2001 | $19.5 million | ($5.2 million) | ($6.1 million) |
| Kettle Falls Bi-Fuels | 10MW | Leased 12 Months | 07-13-01 | $4.4mm | $ 122.00 (5 Mths)<br>$ 56.00 (11 Mths) | $ 73.00 | 05-10-2001 | $4.1 million | $1.3 million | ($203 thousand) |
| Othello CT | 23MW | Purchased | 10-01-01 | $19.0mm | $ 15.26 | $ 90.00 | 04-02-2001 | ($240 thousand) - 25 yrs | ($15.6 million) | ($25.5 million) |
| Boulder Park | 25MW | Purchased | 09-01-01 | $21.0mm | $ 14.42 | $ 50.00 | 05-18-2001 | $11.0 million - 25 yrs | ($5.6 million) | ($10.9 million) |
| SIP | 8MW | Purchased | 09-01-01 | $8.5mm | $ 24.84 | $ 50.00 | 05-18-2001 | ($360 thousand) - 25 yrs | ($4.2 million) | ($6.0 million) |

| Project | Theoretical Option Value: Strike | Theoretical Option Value: Premium/MWh* | Theoretical Option Value: Total Premium** | Estimated Exit and Sunk Costs |
|---|---|---|---|---|
| Devil's Gap | $ 90 | $ 38 | $6.6 million | $11.7 million |
| Kettle Falls Bi-Fuels | $ 73 | $ 55 | $2.0 million | $2.6 million |
| Othello CT | $ 90 | $ 39 | $7.9 million | $2.8 million |
| Boulder Park | $ 50 | $ 50 | $10.8 million | $10.2 million |
| SIP | $ 50 | $ 50 | $3.5 million | $2.8 million |

*Premium calculation is an average of monthly premiums based on a daily call option beginning July 1, (for Devil's Gap/Kettle Falls) September 1 (for Boulder/SIP), and October 1 (for Othello). Volatility is assumed to be 175% compared to a flat market in each month.
**Total Premium is calculated by multiplying capacity and 12 months (5 months for Kettle Falls)
***Variable cost calculated using $1.00/gallon diesel and $5.00/MMBtu natural gas.

CONFIDENTIAL
June 19, 2001
Jason Thackston

**CONFIDENTIAL**

Avista Corp
Small Generation - Option Premium vs. Cost to Complete
June 19, 2001 Analysis

| | Original Project Total Cost | Committed Cost (or cost to terminate) | Cost to Complete | 1-Year Option Premium Value | Net Benefit of Project Compared to 1-Year Option Value |
|---|---|---|---|---|---|
| Boulder Park | $ 21.00 | $ 10.20 | $ 10.80 | $ 10.80 | $ - |
| SIP | $ 8.50 | $ 2.80 | $ 5.70 | $ 3.50 | $ (2.20) |
| K Falls | $ 4.40 | $ 2.60 | $ 1.80 | $ 2.00 | $ 0.20 |
| Devils Gap | $ 11.70 | $ 11.70 | $ - | $ 6.60 | $ 6.60 |
| Othello | $ 19.00 | $ 2.80 | $ 16.20 | $ 7.90 | $ (8.30) |

Note: All $ amounts in millions

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| 19-Jun-01 | Mid C Prices Heavy Load | Mid C Prices Light Load | Rathdrum Gas Prices @ Jun 14 | Marginal Rathdrum Thermal Cost | CS II, RCT, & NECT Actual Gas Prices | Dth/Day w/Fixed Prices |
|---|---|---|---|---|---|---|
| Real-Time | $ 82.50 | $ 70.00 | | | | |
| June - Next Day | $ 88.00 | $ 60.00 | $ 3.32 | $ 40.86 | | |
| June Balance | $ 78.50 | $ 55.00 | $ 3.32 | $ 40.86 | $ 5.17 | 35,000 |
| July | $ 116.00 | | $ 4.20 | $ 51.42 | $ 4.64 | 40,000 |
| August | $ 129.50 | | $ 4.31 | $ 52.74 | $ 5.02 | 55,000 |
| September | $ 108.00 | | $ 4.36 | $ 53.34 | $ 5.02 | 55,000 |
| Q4 2001 | $ 103.00 | | $ 5.15 | $ 62.82 | $ 5.39 | 55,000 |
| Q1 2002 | $ 85.00 | | $ 5.37 | $ 65.46 | $ 6.32 | 28,500 |
| Q2 2002 | $ 43.50 | | $ 4.33 | $ 52.98 | $ 6.28 | 35,000 |
| Q3 2002 | $ 90.00 | | $ 4.07 | $ 49.86 | $ 6.18 | 48,000 |
| Calendar 2002 | $ 70.50 | $ 52.50 | $ 4.54 | $ 55.50 | $ 6.24 | 39,875 |
| Calendar 2003 | $ 48.50 | $ 36.00 | $ 4.08 | $ 49.98 | $ 6.21 | 44,667 |
| Calendar 2004 | $ 41.00 | | $ 4.30 | $ 52.62 | | |
| Calendar 2005 | $ 40.50 | | $ 4.32 | $ 52.86 | | |

| 18-Jun-01 | Mid C Prices Heavy Load | Mid C Prices Light Load | Rathdrum Gas Prices @ Jun 14 | Marginal Rathdrum Thermal Cost |
|---|---|---|---|---|
| Real-Time | $ 105.00 | $ 50.00 | | |
| June - Next Day | $ 105.00 | $ 65.00 | $ 3.32 | $ 40.86 |
| June Balance | $ 103.00 | $ 58.00 | $ 3.32 | $ 40.86 |
| July | $ 142.50 | $ 88.00 | $ 4.20 | $ 51.42 |
| August | $ 170.00 | | $ 4.31 | $ 52.74 |
| September | $ 117.50 | $ 96.50 | $ 4.36 | $ 53.34 |
| Q4 2001 | $ 107.50 | | $ 5.15 | $ 62.82 |
| Q1 2002 | $ 90.00 | | $ 5.37 | $ 65.46 |
| Q2 2002 | $ 49.00 | | $ 4.33 | $ 52.98 |
| Q3 2002 | $ 99.00 | | $ 4.07 | $ 49.86 |
| Calendar 2002 | $ 74.50 | | $ 4.54 | $ 55.50 |
| Calendar 2003 | $ 48.13 | | $ 4.08 | $ 49.98 |
| Calendar 2004 | $ 41.25 | | $ 4.30 | $ 52.62 |
| Calendar 2005 | $ 40.50 | | $ 4.32 | $ 52.86 |

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*Avista Utilities*

Position Report

2001-06-19.xls

Indicates positions outside of risk policy limits

| Month | Hrs | Index Purchase (Sale) [a] | Physical Position Long (Short) [b] | Financial Put (Call) Net Delta [c] | Open Position Long (Short) [d] | CT Inc in Phy Sur(Def)[e] | CT Turb. Fuel Purchased [f] | Financial Open Position [g] | Financial Quarter Average | Fin & NG Open Position [h] | Month Short Limit | Month Long Limit | Fin & NG Quarter Average | Quarter Short Limit | Quarter Long Limit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Col (1) | Col (2) | Col (3) | Col (4) Col (2) + Col (3) | Col (5) | Col (6) | Col (7) Col (4) - Col (1) | Col (8) Avg Col (8) | Col (9) Col (7) - (5) + (6) | Col (10) | Col (11) | Col (12) Avg Col 10 | Col (13) | Col (14) |
| Jul-01 | HL | (20) | 103 | 0 | 103 | 182 | 139 | 123 | | 80 | (75) | 200 | | | |
| Jul-01 | LL | (20) | 91 | 0 | 91 | 180 | 139 | 111 | | 70 | (75) | 200 | | | |
| Aug-01 | HL | (10) | 56 | 0 | 56 | 190 | 187 | 66 | 113 | 63 | (75) | 200 | 94 | (25) | 150 |
| Aug-01 | LL | (10) | 80 | 0 | 80 | 190 | 187 | 90 | 120 | 87 | (75) | 200 | 102 | (25) | 150 |
| Sep-01 | HL | (20) | 129 | 0 | 129 | 198 | 187 | 149 | | 138 | (75) | 200 | | | |
| Sep-01 | LL | (20) | 139 | 0 | 139 | 198 | 187 | 159 | | 149 | (75) | 200 | | | |
| Oct-01 | HL | (20) | (79) | 0 | (79) | 198 | 187 | (59) | | (70) | (150) | 250 | | | |
| Oct-01 | LL | (20) | 128 | 0 | 128 | 198 | 187 | 148 | | 137 | (150) | 250 | | | |
| Nov-01 | HL | (20) | (30) | 0 | (30) | 211 | 188 | (10) | (15) | (33) | (150) | 250 | (34) | (50) | 150 |
| Nov-01 | LL | (20) | 109 | (63) | 46 | 152 | 188 | 66 | 87 | 102 | (150) | 250 | 107 | (50) | 150 |
| Dec-01 | HL | (19) | 6 | 0 | 6 | 211 | 188 | 25 | | 2 | (150) | 250 | | | |
| Dec-01 | LL | (20) | 74 | (49) | 26 | 152 | 188 | 46 | | 82 | (150) | 250 | | | |
| Jan-02 | HL | (5) | 158 | 0 | 158 | 152 | 69 | 163 | | 80 | (150) | 250 | | | |
| Jan-02 | LL | (5) | 257 | (53) | 204 | 152 | 69 | 209 | | 126 | (150) | 250 | | | |
| Feb-02 | HL | (5) | 274 | 0 | 274 | 152 | 69 | 279 | 263 | 196 | (150) | 250 | 181 | (50) | 150 |
| Feb-02 | LL | (5) | 334 | (42) | 292 | 152 | 69 | 297 | 280 | 214 | (150) | 250 | 198 | (50) | 150 |
| Mar-02 | HL | (5) | 340 | 0 | 340 | 149 | 69 | 345 | | 265 | (150) | 250 | | | |
| Mar-02 | LL | (5) | 373 | (43) | 330 | 149 | 69 | 335 | | 255 | (150) | 250 | | | |
| Apr-02 | HL | (5) | 266 | (61) | 205 | 149 | 69 | 210 | | 130 | (150) | 250 | | | |
| Apr-02 | LL | (5) | 269 | (9) | 260 | 149 | 69 | 265 | | 185 | (150) | 250 | | | |
| May-02 | HL | (5) | 355 | 0 | 355 | 147 | 69 | 360 | 312 | 282 | (150) | 250 | 269 | (50) | 150 |
| May-02 | LL | (5) | 343 | 0 | 343 | 147 | 69 | 348 | 331 | 270 | (150) | 250 | 287 | (50) | 150 |
| Jun-02 | HL | (5) | 418 | (57) | 361 | 110 | 139 | 366 | | 394 | (150) | 250 | | | |
| Jun-02 | LL | (5) | 420 | (46) | 374 | 110 | 139 | 379 | | 408 | (150) | 250 | | | |
| Jul-02 | HL | (5) | 324 | 0 | 324 | 143 | 139 | 329 | | 325 | (175) | 250 | | | |
| Jul-02 | LL | (5) | 296 | 0 | 296 | 143 | 139 | 301 | | 298 | (175) | 250 | | | |
| Aug-02 | HL | 5 | 146 | 0 | 146 | 375 | 242 | 142 | 214 | 9 | (175) | 250 | 120 | (75) | 150 |
| Aug-02 | LL | 5 | 443 | 0 | 443 | 375 | 242 | 438 | 402 | 305 | (175) | 250 | 309 | (75) | 150 |
| Sep-02 | HL | (5) | 165 | 0 | 165 | 385 | 242 | 170 | | 27 | (175) | 250 | | | |
| Sep-02 | LL | (5) | 462 | 0 | 462 | 385 | 242 | 467 | | 325 | (175) | 250 | | | |
| Oct-02 | HL | (5) | 296 | 0 | 296 | 392 | 242 | 301 | | 150 | (175) | 250 | | | |
| Oct-02 | LL | (5) | 476 | 0 | 476 | 392 | 242 | 481 | | 330 | (175) | 250 | | | |
| Nov-02 | HL | (5) | 471 | 0 | 471 | 404 | 242 | 476 | 455 | 314 | (175) | 250 | 296 | (75) | 150 |
| Nov-02 | LL | (5) | 552 | (44) | 508 | 404 | 242 | 513 | 511 | 351 | (175) | 250 | 352 | (75) | 150 |
| Dec-02 | HL | (5) | 585 | 0 | 585 | 408 | 242 | 590 | | 424 | (175) | 250 | | | |
| Dec-02 | LL | (5) | 576 | (42) | 534 | 408 | 242 | 539 | | 373 | (175) | 250 | | | |

| Month | Hrs | Hrs | Impact of $50 Price Increase |
|---|---|---|---|
| Jul-01 | HL | 400 | $ 2,464,476 |
| Jul-01 | LL | 344 | $ 1,913,198 |
| Aug-01 | HL | 432 | $ 1,429,825 |
| Aug-01 | LL | 312 | $ 1,411,295 |
| Sep-01 | HL | 384 | $ 2,854,539 |
| Sep-01 | LL | 336 | $ 2,674,181 |
| Oct-01 | HL | 432 | $ (1,282,247) |
| Oct-01 | LL | 312 | $ 2,310,122 |
| Nov-01 | HL | 400 | $ (192,504) |
| Nov-01 | LL | 320 | $ 1,062,981 |
| Dec-01 | HL | 400 | $ 499,508 |
| Dec-01 | LL | 344 | $ 785,481 |
| Jan-02 | HL | 416 | $ 3,392,234 |
| Jan-02 | LL | 328 | $ 3,424,191 |
| Feb-02 | HL | 384 | $ 5,365,989 |
| Feb-02 | LL | 288 | $ 4,272,553 |
| Mar-02 | HL | 416 | $ 7,183,210 |
| Mar-02 | LL | 328 | $ 5,493,676 |
| Apr-02 | HL | 416 | $ 4,373,237 |
| Apr-02 | LL | 304 | $ 4,027,736 |
| May-02 | HL | 416 | $ 7,488,012 |
| May-02 | LL | 328 | $ 5,709,275 |
| Jun-02 | HL | 400 | $ 7,312,761 |
| Jun-02 | LL | 320 | $ 6,066,561 |
| Jul-02 | HL | 416 | $ 6,840,908 |
| Jul-02 | LL | 328 | $ 4,943,369 |
| Aug-02 | HL | 432 | $ 3,062,581 |
| Aug-02 | LL | 312 | $ 6,833,224 |
| Sep-02 | HL | 384 | $ 3,262,069 |
| Sep-02 | LL | 336 | $ 7,850,116 |
| Jan-00 | 0 | | |
| Oct-02 | HL | 432 | $ 6,492,059 |
| Oct-02 | LL | 312 | $ 7,497,087 |
| Nov-02 | HL | 400 | $ 9,512,641 |
| Nov-02 | LL | 320 | $ 8,210,834 |
| Dec-02 | HL | 400 | $ 11,793,163 |
| Dec-02 | LL | 344 | $ 9,267,471 |

Footnotes: [a] Index transactions are already included in the total physical position. [b] Physical position. [c] Aggregate physical equivalent (delta) position of options (put and calls). [d] Open position is the combined physical and delta positions. [e] Turbines in this column represent the amount available as reflected in Physical Surplus-(Deficiency) tab. [f] CT Turbine Fuel Purchased is the amount of natural gas purchased at a fixed price. [g] Open financial position includes open physical position less any index position. [h] Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased. At its meeting on May 30, 2001, the Risk Management Committee suspended the cure date for the positions in 2002 which are longer than the long limits. These positions will be re-evaluated on a monthly basis by the Risk Management Committee.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-22)

**AVISTA Corp.**

*Energy Resources*

**Date:** December 4, 2000

**To:** Jim Jewell/Jerry Parmentier/Tim Carlberg/Bob Lafferty/Steve Wenke/Clint Kalich

**From:** Bill Johnson

**Subject:** Rates of Return on Investment to Operate Northeast Additional Hours

I've calculated returns on a $3 million investment in pollution control equipment for Northeast combustion turbine. The premise of the analysis is that the investment in the pollution control equipment will increase the hours we can operate the turbine from 500 hours per year to at least 3,000 hours per year. I valued the increased generation in two ways, 1) as the value of increased generation, and 2) as the value of the turbine as on option with a strike price at the incremental fuel cost. For increased generation, Clint built a model to optimize the plant for 500 hours of operation and for 3,000 hours. The value is the increased margins for 3,000 hours of operation versus 500 hours of operation. The option value of the plant is based on a $15/MWh premium in the first year that decreases to less than $6/MWh in the 10$^{th}$ year as market prices decrease relative to the plants incremental fuel cost. Both analyses assume a 10-year life.

The analysis indicates that the plant would generate margins primarily in the July through December period. If we were to construct additional generation at the Northeast site, then the value of additional generation would decrease due to transmission limitations during summer months.

The results are shown below. Supporting workpapers are attached.

| | Increased Energy | Option Value |
|---|---|---|
| Rate of Return | 42% | 49% |

AVI. CORP

NORTHEAST TURBINE ADDITIONAL HOURS ANALYSIS - ~~WATER INJECTION~~ Dry Low NOx

| | |
|---|---|
| Capital Cost | $3,000,000 |
| Additional Hours of Operation | 2,500 |
| 2001 Flat Price | $68.73 |
| 2001 Call Value $/MWh | $15 Reduces to $5.81/MWh in 2010 |

| Period | Date | Revenues | Incremental O&M | Property Taxes | Tax Depreciation Expense | Income Tax Expense | Capital Expenditure | After-tax Cash Flows | Present Value ATCF | Cumulative PV ATCF | Incremental IRR | Revenue Requirements | Incremental Revenue Requirements |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SUM | | 12,700,770 | 2,800,845 | 422,970 | 3,000,000 | 2,266,934 | 3,000,000 | 4,210,020 | 2,360,118 | | | 10,423,183 | -2,277,588 |
| NPV | | 7,698,465 | 1,657,733 | 250,989 | 1,680,222 | 1,853,698 | 2,762,685 | 2,360,118 | | | | 5,785,718 | -3,099,506 |
| LEV | | 700,448 | 150,830 | 22,836 | 152,876 | 168,660 | 251,364 | 214,736 | | | | 584,874 | -313,327 |
| ESC | | | | | | | Discounted Payback: | | 2.94 | IRR: | 48.60% | | |
| 0 | 2000 | | | | | | | | | | | 0 | 0 |
| 1 | 2001 | 1,950,000 | 0 | 41,240 | 150,000 | 615,566 | 3,000,000 | -1,706,806 | -1,571,789 | -1,571,789 | #NUM! | 530,055 | -1,419,945 |
| 2 | 2002 | 1,755,000 | 250,000 | 39,125 | 285,000 | 413,306 | 0 | 1,052,569 | 892,629 | -679,160 | -38.33% | 847,745 | -907,255 |
| 3 | 2003 | 1,579,500 | 256,250 | 37,010 | 256,500 | 360,409 | 0 | 925,831 | 723,040 | 43,880 | 10.68% | 825,466 | -754,034 |
| 4 | 2004 | 1,421,550 | 262,656 | 34,895 | 231,000 | 312,550 | 0 | 811,449 | 583,582 | 627,462 | 30.87% | 804,658 | -616,892 |
| 5 | 2005 | 1,279,395 | 269,223 | 32,780 | 207,900 | 269,322 | 0 | 708,070 | 468,950 | 1,096,412 | 39.89% | 785,195 | -494,200 |
| 6 | 2006 | 1,151,456 | 275,953 | 30,665 | 186,900 | 230,278 | 0 | 614,559 | 374,822 | 1,471,234 | 44.25% | 766,973 | -384,483 |
| 7 | 2007 | 1,036,310 | 282,852 | 28,550 | 177,000 | 191,768 | 0 | 533,140 | 299,442 | 1,770,676 | 46.49% | 749,675 | -286,635 |
| 8 | 2008 | 932,679 | 289,923 | 26,436 | 177,000 | 153,762 | 0 | 462,558 | 239,248 | 2,009,923 | 47.69% | 732,798 | -199,881 |
| 9 | 2009 | 839,411 | 297,171 | 24,321 | 177,300 | 119,217 | 0 | 398,702 | 189,907 | 2,199,830 | 48.35% | 716,099 | -123,312 |
| 10 | 2010 | 755,470 | 304,601 | 22,206 | 177,000 | 88,082 | 0 | 340,581 | 149,390 | 2,349,220 | 48.71% | 699,590 | -55,880 |

WGJ
10-12-2000

AVIS CORP

NORTHEAST TURBINE ADDITIONAL HOURS ANALYSIS - ~~WATER INJECTION~~ Dry Low NOx

Capital Cost $3,000,000

Additional Hours of Operation 2,500

2001 Flat Price $52.38

| Period | Date | Incremental Revenues | Incremental O&M | Property Taxes | Tax Depreciation Expense | Income Tax Expense | Capital Expenditure | After-tax Cash Flows | Present Value ATCF | Cumulative PV ATCF | Incremental IRR | Revenue Requirements | Incremental Revenue Requirements |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SUM | | 71,515,641 | 56,591,703 | 422,970 | 3,000,000 | 4,025,339 | 3,000,000 | 7,475,629 | 3,891,119 | | | 66,790,241 | -4,725,401 |
| NPV | | 45,753,996 | 36,518,386 | 250,989 | 1,680,222 | 2,678,083 | 2,762,685 | 3,891,119 | | | | 42,315,949 | -3,785,314 |
| LEV | | 4,162,947 | 3,322,641 | 22,836 | 152,876 | 243,667 | 251,364 | 354,035 | | | | 4,277,692 | -382,655 |
| ESC | | | | | | | Discounted Payback: | | 3.66 | IRR: | 41.96% | | |
| 0 | 2000 | | | | | | | | | | | 0 | 0 |
| 1 | 2001 | 4,307,365 | 3,695,391 | 41,240 | 150,000 | 147,257 | 3,000,000 | -2,576,523 | -2,372,707 | -2,372,707 | #NUM! | 4,402,429 | 95,064 |
| 2 | 2002 | 8,263,211 | 6,563,093 | 39,125 | 285,000 | 481,598 | 0 | 1,179,396 | 1,000,184 | -1,372,523 | #NUM! | 7,463,191 | -800,021 |
| 3 | 2003 | 7,666,762 | 6,094,115 | 37,010 | 256,500 | 447,698 | 0 | 1,087,939 | 849,640 | -522,883 | -8.22% | 6,942,923 | -723,839 |
| 4 | 2004 | 7,616,668 | 6,010,006 | 34,895 | 231,000 | 469,268 | 0 | 1,102,498 | 792,900 | 270,017 | 14.92% | 6,827,265 | -789,403 |
| 5 | 2005 | 6,984,331 | 5,165,333 | 32,780 | 207,900 | 552,411 | 0 | 1,233,807 | 817,143 | 1,087,160 | 27.87% | 5,915,794 | -1,068,537 |
| 6 | 2006 | 7,171,833 | 5,392,717 | 30,665 | 186,900 | 546,543 | 0 | 1,201,908 | 733,048 | 1,820,208 | 34.61% | 6,128,793 | -1,043,040 |
| 7 | 2007 | 6,954,147 | 5,608,143 | 28,550 | 177,000 | 399,159 | 0 | 918,295 | 515,767 | 2,335,975 | 37.63% | 6,330,009 | -624,138 |
| 8 | 2008 | 7,326,828 | 5,830,937 | 26,436 | 177,000 | 452,359 | 0 | 1,017,096 | 526,070 | 2,862,045 | 39.72% | 6,539,187 | -787,641 |
| 9 | 2009 | 7,657,489 | 6,019,073 | 24,321 | 177,300 | 502,878 | 0 | 1,111,217 | 529,286 | 3,391,331 | 41.15% | 6,712,039 | -945,450 |
| 10 | 2010 | 7,567,007 | 6,212,896 | 22,206 | 177,000 | 404,217 | 0 | 927,688 | 406,915 | 3,798,246 | 41.93% | 6,890,851 | -676,156 |

WGJ
10-12-2000

| Month | Hours | | | Market Prices | | | Operating | Hours Operated | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | HLH | LLH | Total | HLH ($/MWh) | LLH ($/MWh) | Gas ($/dth) | Cost ($/MWh) | HLH | LLH | Total | Ann. Total |
| Jan-01 | 424 | 320 | 744 | 61.3 | 41.8 | 3.557 | 52.8 | 0.0 | 0.0 | 0.0 | |
| Feb-01 | 383 | 289 | 672 | 61.4 | 41.3 | 3.557 | 52.8 | 0.0 | 0.0 | 0.0 | |
| Mar-01 | 424 | 320 | 744 | 70.3 | 47.3 | 3.557 | 52.8 | 0.0 | 0.0 | 0.0 | |
| Apr-01 | 410 | 309 | 719 | 45.7 | 29.5 | 3.557 | 52.8 | 0.0 | 0.0 | 0.0 | |
| May-01 | 424 | 320 | 744 | 41.4 | 23.9 | 3.557 | 52.8 | 0.0 | 0.0 | 0.0 | |
| Jun-01 | 410 | 310 | 720 | 41.4 | 24.6 | 3.557 | 52.8 | 0.0 | 0.0 | 0.0 | |
| Jul-01 | 424 | 320 | 744 | 63.9 | 31.2 | 3.557 | 52.8 | 0.0 | 0.0 | 0.0 | |
| Aug-01 | 424 | 320 | 744 | 112.1 | 41.6 | 3.557 | 52.8 | 0.0 | 0.0 | 0.0 | |
| Sep-01 | 410 | 310 | 720 | 85.6 | 46.6 | 3.557 | 52.8 | 410.4 | 0.0 | 410.4 | |
| Oct-01 | 425 | 320 | 745 | 60.4 | 36.6 | 3.557 | 52.8 | 424.7 | 0.0 | 424.7 | |
| Nov-01 | 410 | 310 | 720 | 65.4 | 44.2 | 3.557 | 52.8 | 410.4 | 0.0 | 410.4 | |
| Dec-01 | 424 | 320 | 744 | 59.3 | 41.4 | 3.557 | 52.8 | 424.1 | 0.0 | 424.1 | 1,669.5 |
| Jan-02 | 424 | 320 | 744 | 47.2 | 32.9 | 2.910 | 43.8 | 424.1 | 0.0 | 424.1 | |
| Feb-02 | 383 | 289 | 672 | 47.1 | 32.8 | 2.910 | 43.8 | 0.0 | 0.0 | 0.0 | |
| Mar-02 | 424 | 320 | 744 | 47.2 | 35.6 | 2.910 | 43.8 | 58.2 | 0.0 | 58.2 | |
| Apr-02 | 410 | 309 | 719 | 36.8 | 26.2 | 2.910 | 43.8 | 0.0 | 0.0 | 0.0 | |
| May-02 | 424 | 320 | 744 | 33.6 | 21.6 | 2.910 | 43.8 | 0.0 | 0.0 | 0.0 | |
| Jun-02 | 410 | 310 | 720 | 34.8 | 21.5 | 2.910 | 43.8 | 0.0 | 0.0 | 0.0 | |
| Jul-02 | 424 | 320 | 744 | 53.9 | 28.3 | 2.910 | 43.8 | 424.1 | 0.0 | 424.1 | |
| Aug-02 | 424 | 320 | 744 | 63.2 | 36.2 | 2.910 | 43.8 | 424.1 | 0.0 | 424.1 | |
| Sep-02 | 410 | 310 | 720 | 65.9 | 41.6 | 2.910 | 43.8 | 410.4 | 0.0 | 410.4 | |
| Oct-02 | 425 | 320 | 745 | 52.3 | 33.7 | 2.910 | 43.8 | 424.7 | 0.0 | 424.7 | |
| Nov-02 | 410 | 310 | 720 | 59.7 | 39.2 | 2.910 | 43.8 | 410.4 | 0.0 | 410.4 | |
| Dec-02 | 424 | 320 | 744 | 57.1 | 39.5 | 2.910 | 43.8 | 424.1 | 0.0 | 424.1 | 3,000.0 |
| Jan-03 | 424 | 320 | 744 | 42.4 | 30.4 | 2.682 | 40.7 | 0.0 | 0.0 | 0.0 | |
| Feb-03 | 383 | 289 | 672 | 42.5 | 30.4 | 2.682 | 40.7 | 58.2 | 0.0 | 58.2 | |
| Mar-03 | 424 | 320 | 744 | 44.3 | 32.7 | 2.682 | 40.7 | 424.1 | 0.0 | 424.1 | |
| Apr-03 | 410 | 309 | 719 | 32.8 | 24.7 | 2.682 | 40.7 | 0.0 | 0.0 | 0.0 | |
| May-03 | 424 | 320 | 744 | 30.1 | 20.4 | 2.682 | 40.7 | 0.0 | 0.0 | 0.0 | |
| Jun-03 | 410 | 310 | 720 | 30.5 | 19.9 | 2.682 | 40.7 | 0.0 | 0.0 | 0.0 | |
| Jul-03 | 424 | 320 | 744 | 49.3 | 25.2 | 2.682 | 40.7 | 424.1 | 0.0 | 424.1 | |
| Aug-03 | 424 | 320 | 744 | 57.1 | 31.4 | 2.682 | 40.7 | 424.1 | 0.0 | 424.1 | |
| Sep-03 | 410 | 310 | 720 | 61.2 | 36.6 | 2.682 | 40.7 | 410.4 | 0.0 | 410.4 | |
| Oct-03 | 425 | 320 | 745 | 48.4 | 30.2 | 2.682 | 40.7 | 424.7 | 0.0 | 424.7 | |
| Nov-03 | 410 | 310 | 720 | 56.3 | 36.5 | 2.682 | 40.7 | 410.4 | 0.0 | 410.4 | |
| Dec-03 | 424 | 320 | 744 | 53.9 | 37.5 | 2.682 | 40.7 | 424.1 | 0.0 | 424.1 | 3,000.0 |
| Jan-04 | 424 | 320 | 744 | 40.7 | 29.6 | 2.704 | 41.1 | 0.0 | 0.0 | 0.0 | |
| Feb-04 | 397 | 299 | 696 | 34.0 | 25.8 | 2.704 | 41.1 | 0.0 | 0.0 | 0.0 | |
| Mar-04 | 424 | 320 | 744 | 41.5 | 30.8 | 2.704 | 41.1 | 424.1 | 0.0 | 424.1 | |
| Apr-04 | 410 | 309 | 719 | 31.7 | 24.5 | 2.704 | 41.1 | 0.0 | 0.0 | 0.0 | |
| May-04 | 424 | 320 | 744 | 27.9 | 20.5 | 2.704 | 41.1 | 0.0 | 0.0 | 0.0 | |
| Jun-04 | 410 | 310 | 720 | 32.8 | 20.6 | 2.704 | 41.1 | 0.0 | 0.0 | 0.0 | |
| Jul-04 | 424 | 320 | 744 | 49.6 | 26.6 | 2.704 | 41.1 | 424.1 | 0.0 | 424.1 | |
| Aug-04 | 424 | 320 | 744 | 72.4 | 32.2 | 2.704 | 41.1 | 424.1 | 0.0 | 424.1 | |
| Sep-04 | 410 | 310 | 720 | 67.1 | 36.1 | 2.704 | 41.1 | 410.4 | 0.0 | 410.4 | |
| Oct-04 | 425 | 320 | 745 | 49.8 | 32.3 | 2.704 | 41.1 | 424.7 | 0.0 | 424.7 | |

| | Hours | | | Market Prices | | | Operating | Hours Operated | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Month | HLH | LLH | Total | HLH ($/MWh) | LLH ($/MWh) | Gas ($/dth) | Cost ($/MWh) | HLH | LLH | Total | Ann. Total |
| Nov-04 | 410 | 310 | 720 | 54.2 | 37.2 | 2.704 | 41.1 | 410.4 | 0.0 | 410.4 | |
| Dec-04 | 424 | 320 | 744 | 53.0 | 39.2 | 2.704 | 41.1 | 424.1 | 0.0 | 424.1 | 2,941.8 |
| Jan-05 | 424 | 320 | 744 | 42.3 | 29.9 | 2.817 | 42.8 | 0.0 | 0.0 | 0.0 | |
| Feb-05 | 383 | 289 | 672 | 41.5 | 30.4 | 2.817 | 42.8 | 0.0 | 0.0 | 0.0 | |
| Mar-05 | 424 | 320 | 744 | 42.5 | 31.4 | 2.817 | 42.8 | 0.0 | 0.0 | 0.0 | |
| Apr-05 | 410 | 309 | 719 | 33.0 | 25.1 | 2.817 | 42.8 | 0.0 | 0.0 | 0.0 | |
| May-05 | 424 | 320 | 744 | 29.6 | 21.4 | 2.817 | 42.8 | 0.0 | 0.0 | 0.0 | |
| Jun-05 | 410 | 310 | 720 | 34.6 | 21.3 | 2.817 | 42.8 | 0.0 | 0.0 | 0.0 | |
| Jul-05 | 424 | 320 | 744 | 52.2 | 27.6 | 2.817 | 42.8 | 424.1 | 0.0 | 424.1 | |
| Aug-05 | 424 | 320 | 744 | 89.3 | 33.0 | 2.817 | 42.8 | 424.1 | 0.0 | 424.1 | |
| Sep-05 | 410 | 310 | 720 | 75.3 | 36.7 | 2.817 | 42.8 | 410.4 | 0.0 | 410.4 | |
| Oct-05 | 425 | 320 | 745 | 52.3 | 33.3 | 2.817 | 42.8 | 424.7 | 0.0 | 424.7 | |
| Nov-05 | 410 | 310 | 720 | 56.8 | 38.4 | 2.817 | 42.8 | 410.4 | 0.0 | 410.4 | |
| Dec-05 | 424 | 320 | 744 | 55.6 | 40.3 | 2.817 | 42.8 | 424.1 | 0.0 | 424.1 | 2,517.7 |

## Emerson, John

**From:** Emerson, John
**Sent:** Monday, December 04, 2000 5:17 PM
**To:** Brukardt, David; Burmeister-Smith, Christy; Eliassen, Jon; Ely, Gary; Emerson, John; Gorton, Pat; Groce, Ed; Hemstrom, Steve; Hubbard, Dale; Jenkins, Thomas; Jewell, Jim; Mattern, Kim; Morris, Scott; Norwood, Kelly; Payne, William; Peterson, Ron; Steiner, Nolan; Stevens, Rich; Storro, Dick; Thackston, Jason
**Subject:** Position Report

**Purchases and Sales:** Prices for pre-scheduled load for Tuesday were about $270 for heavy and $220 for light. For Tuesday, we were a net purchaser of 25 aMW heavy load. A change to Clark Fork December streamflows due to an unscheduled storage water release from Kerr is being analyzed. The estimated impact of this change will be an increase in resources of 55 aMW on peak. A decrease in storage water in Q1 2001 will also be involved, most likely in March. These changes have not been reflected in today's report--they will be included later this week.

Dec0400position.xls

**Hydro:**
**Colstrip:** Both units running.
**Rathdrum:** Both units running.
**Northeast Combustion Turbine:** Down for combustion inspection and maintenance. Expected back Friday Dec 8 PM.
**Loads:**
**Prices:**

| 4-Dec | Heavy Load Mid C Prices | Light Load Mid C Prices | Gas Prices @ Dec 4 | Marginal Rathdrum Thermal Cost |
|---|---|---|---|---|
| Real-Time | $ 260.00 | $ 205.00 | | |
| Dec - Next Day | $ 270.00 | $ 220.00 | $ 20.00 | $ 241.02 |
| Dec - Balance | $ 650.00 | $ 230.00 | $ 20.00 | $ 241.02 |
| January | $ 580.00 | $ 220.00 | $ 16.93 | $ 204.18 |
| February | $ 315.00 | na | $ 11.54 | $ 139.50 |
| Q1 2001 | $ 362.50 | $ 157.50 | $ 12.53 | $ 151.38 |
| Q2 2001 | $ 187.50 | $ 110.00 | $ 7.60 | $ 92.22 |
| Q3 2001 | $ 250.00 | $ 130.00 | $ 7.33 | $ 88.98 |
| Q4 2001 | $ 145.00 | $ 56.00 | $ 6.99 | $ 84.90 |
| Calendar 2001 | $ 236.25 | $ 113.38 | | |
| **1-Dec** | **Heavy Load Mid C Prices** | **Light Load Mid C Prices** | **Gas Prices @ Nov 27** | **Marginal Rathdrum Thermal Cost** |
| Real-Time | $ 250.00 | $ 200.00 | | |
| Dec - Next Day | $ 270.00 | $ 220.00 | $ 14.00 | $ 169.02 |
| Dec - Balance | $ 312.50 | $ 230.00 | $ 14.25 | $ 172.02 |
| January | $ 275.00 | $ 220.00 | $ 10.50 | $ 127.02 |
| February | $ 220.00 | na | $ 8.50 | $ 103.02 |
| Q1 2001 | $ 215.00 | $ 157.50 | $ 8.05 | $ 97.62 |
| Q2 2001 | $ 126.00 | $ 110.00 | $ 5.80 | $ 70.62 |
| Q3 2001 | $ 202.00 | $ 130.00 | $ 5.70 | $ 69.42 |
| Q4 2001 | $ 223.00 | $ 56.00 | $ 5.60 | $ 68.22 |
| Calendar 2001 | $ 191.50 | $ 113.38 | | |

fidential

# Avis 'ltilities
## Posi. ., Report
December 4, 2000

| Month & Hours | Index Purchase (Sale) (a) (1) | Physical Position Long (Short) (b) (2) | Financial Put (Call) et Delta "(c)" (3) | Total Position Long (Short) (d) (4) | Rath Turb Inc in Phy Fuel Pur (5) | Rathdrum Turb. Fuel Not Pur (e) (6) | Physical Open Position (f) (7) | Financial Open Position (g) (8) | Financial Quarter Average (9) | Fin & NG Open Position (h) (10) | Month Short Limit (11) | Month Long Limit (12) | Fin & NG Quarter Average (13) | Quarter Short Limit (14) | Quarter Long Limit (15) | Month & Hours | Hrs | Impact of $10 Increase in Prices |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dec HL | (5) | 22 | 0 | 22 | 168 | 0 | 22 | 27 | | 27 | 0 | 150 | | | | Dec HL | 400 | $ 109,457 |
| Dec LL | (5) | (4) | 0 | (4) | 162 | 0 | (4) | 1 | | 1 | 0 | 150 | | | | Dec LL | 344 | $ 3,683 |
| Jan HL | (5) | 70 | 0 | 70 | 160 | 0 | 70 | 75 | | 75 | (75) | 200 | | | | Jan HL | 416 | $ 313,560 |
| Jan LL | (5) | 32 | 0 | 32 | 160 | 0 | 32 | 37 | | 37 | (75) | 200 | | | | Jan LL | 328 | $ 122,258 |
| Feb HL | (5) | 23 | 0 | 23 | 160 | 0 | 23 | 28 | 19 | 28 | (75) | 200 | 19 | (25) | 150 | Feb HL | 384 | $ 107,154 |
| Feb LL | (5) | 37 | 0 | 37 | 80 | 0 | 37 | 42 | 25 | 42 | (75) | 200 | 25 | (25) | 150 | Feb LL | 288 | $ 119,640 |
| Mar HL | (5) | (52) | 0 | (52) | 80 | 0 | (52) | (47) | | (47) | (75) | 200 | | | | Mar HL | 432 | $ (204,871) |
| Mar LL | (5) | (8) | 0 | (8) | 80 | 0 | (8) | (3) | | (3) | (75) | 200 | | | | Mar LL | 312 | $ (10,733) |
| Apr HL | (5) | (68) | 0 | (68) | 80 | 40 | (28) | (23) | | (63) | (150) | 250 | | | | Apr HL | 400 | $ (93,145) |
| Apr LL | (5) | (133) | 0 | (133) | 0 | 80 | (53) | (48) | | (128) | (150) | 250 | | | | Apr LL | 320 | $ (153,281) |
| May HL | (5) | 51 | 0 | 51 | 0 | 0 | 51 | 56 | 24 | 56 | (150) | 250 | 10 | (50) | 150 | May HL | 416 | $ 232,088 |
| May LL | (5) | 192 | 0 | 192 | 0 | 0 | 192 | 197 | 131 | 197 | (150) | 250 | 104 | (50) | 150 | May LL | 328 | $ 644,601 |
| Jun HL | (5) | 34 | 0 | 34 | 80 | 0 | 34 | 39 | | 39 | (150) | 250 | | | | Jun HL | 416 | $ 161,224 |
| Jun LL | (5) | 238 | 0 | 238 | 0 | 0 | 238 | 243 | | 243 | (150) | 250 | | | | Jun LL | 304 | $ 738,530 |
| Jul HL | (5) | 175 | 0 | 175 | 150 | 0 | 175 | 180 | | 180 | (150) | 250 | | | | Jul HL | 400 | $ 721,977 |
| Jul LL | (5) | (15) | 0 | (15) | 150 | 0 | (15) | (10) | | (10) | (150) | 250 | | | | Jul LL | 344 | $ (35,729) |
| Aug HL | 5 | (73) | 0 | (73) | 150 | 0 | (73) | (78) | 38 | (78) | (150) | 250 | 38 | (50) | 150 | Aug HL | 432 | $ (338,580) |
| Aug LL | 5 | (27) | 0 | (27) | 150 | 0 | (27) | (32) | (5) | (32) | (150) | 250 | (5) | (50) | 150 | Aug LL | 312 | $ (100,620) |
| Sep HL | (5) | 6 | 0 | 6 | 155 | 0 | 6 | 11 | | 11 | (150) | 250 | | | | Sep HL | 384 | $ 41,256 |
| Sep LL | (5) | 23 | 0 | 23 | 155 | 0 | 23 | 28 | | 28 | (150) | 250 | | | | Sep LL | 336 | $ 93,648 |
| Oct HL | (5) | (47) | 0 | (47) | 160 | 0 | (47) | (42) | | (42) | (150) | 250 | | | | Oct HL | 432 | $ (183,214) |
| Oct LL | (5) | 57 | 0 | 57 | 160 | 0 | 57 | 62 | | 62 | (150) | 250 | | | | Oct LL | 312 | $ 194,053 |
| Nov HL | (5) | 60 | 0 | 60 | 160 | 0 | 60 | 65 | 33 | 65 | (150) | 250 | 33 | (50) | 150 | Nov HL | 400 | $ 260,202 |
| Nov LL | (5) | 67 | 0 | 67 | 160 | 0 | 67 | 72 | 45 | 72 | (150) | 250 | 45 | (50) | 150 | Nov LL | 320 | $ 231,467 |
| Dec HL | (5) | 72 | 0 | 72 | 160 | 0 | 72 | 77 | | 77 | (150) | 250 | | | | Dec HL | 400 | $ 306,957 |
| Dec LL | (5) | (5) | 0 | (5) | 160 | 0 | (5) | (0) | | (0) | (150) | 250 | | | | Dec LL | 344 | $ (617) |

Footnotes:

(a) Index transactions are already included in the total physical position.
(b) Physical position.
(c) Aggregate physical equivalent (delta) position of options (put and calls).
(d) Total position is the combined physical and delta positions.
(e) Turbines in this column are available for use, but gas has not been purchased.
When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column.
(f) Open physical position includes total position and available turbines.
(g) Open financial position includes open physical position less any index position.
(h) Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-23)

**AVISTA Corporation**

FILE
KETTLE FALLS
CT
PROJECT

***Interoffice Memorandum***
***Energy Resources***

**DATE:** February 14, 2001

**TO:** Thomas Dempsey

**FROM:** Steve Silkworth

**SUBJECT:** Kettle Falls CT Installation – Revised Economic Evaluation

Thomas – Attached to this memo are the revised economic evaluation results for the proposed combustion turbine addition to the Kettle Falls site. I revised this memo to reflect the economics based upon actual forward market strip prices for electricity and natural gas. In the previous analysis, I used the same price forecast that was prepared by RW Beck consultants for the recent Request for Proposal evaluation. This forecast is 12 weeks old and does not capture recent upswing in the spark spreads.

For easy reference, also attached is a spreadsheet with the annual electric and natural gas prices used in the evaluation.

**Three Cases Analyzed:**

1. Simple cycle only
2. Simple cycle with HRSG and steam sent to feedwater heater in KFGS
3. Combined cycle with Staco mini-steam turbine, steam then sent to DA.

**Economics**

The project economics was evaluated by the method used in Avista's recent Request for Proposal process. This method consisted of:

- Forward strip electric and natural gas prices through 2007 then hourly electric and monthly natural gas price forecast provided by RW Beck through 2025.
- Dispatch of the machine was calculated on an hourly basis by using the Prosym production cost model from February 2002 to December 2025.
- Plant characteristics such as heat rate, VOM and O&M costs, planned maintenance, and capital costs were provided by the Generation and Production department.
- All other costs were modeled consistent with the company's Standard Assumptions Manual and revenue requirements model.

**Economic Results (2001 $'s)**

| | Net Benefit Nominal Levelized $/MWh | Net Benefit Real Levelized $/MWh | Net Present Value $ (000's) |
|---|---|---|---|
| 1. Simple Cycle Only | 12.5 | 9.8 | 3,151 |
| 2. Simple cycle with HRSG and steam sent to feedwater heater | 16.1 | 12.6 | 10,601 |
| 3. Combined cycle with Staco mini-steam turbine, steam then sent to DA | 15.1 | 11.8 | 11,258 |
| | | | |

The results indicate that in all cases, the project returns a positive present value. In other words, each of the cases are lower in cost than equivalent market purchases over the project lives. Cases 2 and 3 have a payback of approximately three years.

If you have any questions, please call me on extension 8093.

**Distribution**:
Ed Groce
Clint Kalich
Jason Thackston
Jerry Parmentier
Steve Wenke

# Kettle Falls Upgrade

## Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Installed Cost | 10,000 | $000s | Fixed Charge | 0.00 | per kW-month | Variable O&M | 2.00 | 2001$/MWh |
| Project Capacity | 9.8 | MW | Fixed O&M | 0.00 | 2003$ per kW-month | | | |
| Heat Rate | 8,750 | Btu/kWh | Escalation Rates | | | Insurance Cost | 0.0 | 0.3% of installed cost ($000s) |
| Peak Gas Useage | 2,048 | 000s dth | Fixed O&M | 2.5 | percent | Gas Transport | 0.00 | 2000 $/dth |
| | | | Variable O&M | 2.5 | percent | Electric Wheeling | 0 | $/MW-month thru 2006 |
| | | | Transportation | 2.0 | percent | General Inflation | 2.5 | percent |

| | | |
|---|---|---|
| Electric Wheeling Losses | 1.9 | percent |
| Nominal Discount Rate | 7.8 | percent |
| Real Discount Rate | 5.1 | percent |

| | | Capital Recovery and Miscellaneous | | | | Fixed Costs: Operations & Maintenance | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Energy (GWh) | Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
| 1 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 2 2002 | 71.9 | 1,766 | 0 | 1,766 | 24.6 | 0 | 0 | 0 | 136 | 0 | 136 | 1.9 |
| 3 2003 | 77.6 | 1,700 | 0 | 1,700 | 21.9 | 0 | 0 | 0 | 132 | 0 | 132 | 1.7 |
| 4 2004 | 75.9 | 1,635 | 0 | 1,635 | 21.6 | 0 | 0 | 0 | 127 | 0 | 127 | 1.7 |
| 5 2005 | 70.6 | 1,565 | 0 | 1,565 | 22.2 | 0 | 0 | 0 | 122 | 0 | 122 | 1.7 |
| 6 2006 | 62.1 | 1,495 | 0 | 1,495 | 24.1 | 0 | 0 | 0 | 117 | 0 | 117 | 1.9 |
| 7 2007 | 56.8 | 1,433 | 0 | 1,433 | 25.2 | 0 | 0 | 0 | 113 | 0 | 113 | 2.0 |
| 8 2008 | 75.9 | 1,373 | 0 | 1,373 | 18.1 | 0 | 0 | 0 | 108 | 0 | 108 | 1.4 |
| 9 2009 | 75.9 | 1,329 | 0 | 1,329 | 17.5 | 0 | 0 | 0 | 103 | 0 | 103 | 1.4 |
| 10 2010 | 76.6 | 1,286 | 0 | 1,286 | 16.8 | 0 | 0 | 0 | 99 | 0 | 99 | 1.3 |
| 11 2011 | 76.7 | 1,243 | 0 | 1,243 | 16.2 | 0 | 0 | 0 | 94 | 0 | 94 | 1.2 |
| 12 2012 | 76.4 | 1,201 | 0 | 1,201 | 15.7 | 0 | 0 | 0 | 89 | 0 | 89 | 1.2 |
| 13 2013 | 75.5 | 1,157 | 0 | 1,157 | 15.3 | 0 | 0 | 0 | 85 | 0 | 85 | 1.1 |
| 14 2014 | 75.4 | 1,114 | 0 | 1,114 | 14.8 | 0 | 0 | 0 | 80 | 0 | 80 | 1.1 |
| 15 2015 | 75.1 | 1,073 | 0 | 1,073 | 14.3 | 0 | 0 | 0 | 75 | 0 | 75 | 1.0 |
| 16 2016 | 74.8 | 1,031 | 0 | 1,031 | 13.8 | 0 | 0 | 0 | 70 | 0 | 70 | 0.9 |
| 17 2017 | 73.7 | 987 | 0 | 987 | 13.4 | 0 | 0 | 0 | 66 | 0 | 66 | 0.9 |
| 18 2018 | 73.2 | 944 | 0 | 944 | 12.9 | 0 | 0 | 0 | 61 | 0 | 61 | 0.8 |
| 19 2019 | 71.9 | 899 | 0 | 899 | 12.5 | 0 | 0 | 0 | 56 | 0 | 56 | 0.8 |
| 20 2020 | 69.8 | 854 | 0 | 854 | 12.2 | 0 | 0 | 0 | 52 | 0 | 52 | 0.7 |
| 21 2021 | 68.1 | 809 | 0 | 809 | 11.9 | 0 | 0 | 0 | 47 | 0 | 47 | 0.7 |
| 22 2022 | 66.4 | 769 | 0 | 769 | 11.6 | 0 | 0 | 0 | 42 | 0 | 42 | 0.6 |
| 23 2023 | 66.3 | 742 | 0 | 742 | 11.2 | 0 | 0 | 0 | 38 | 0 | 38 | 0.6 |
| 24 2024 | 65.5 | 719 | 0 | 719 | 11.0 | 0 | 0 | 0 | 33 | 0 | 33 | 0.5 |
| 25 2025 | 65.3 | 698 | 0 | 698 | 10.7 | 0 | 0 | 0 | 28 | 0 | 28 | 0.4 |
| *2001$* | | | | | | | | | | | | |
| Net Present Value | | 13,141 | 0 | 13,141 | | 0 | 0 | 0 | 979 | 0 | 979 | |
| Nominal Levelized Cost ($/MWh) | | | | | 17.6 | | | | | | | 1.3 |
| Real Levelized Cost ($/MWh) | | | | | 13.8 | | | | | | | 1.0 |

| | Total Fixed Costs | | | Less | Net | | Variable Costs | | | | Total Project Cost after Credits | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Operating Margin ($000s) | Project Benefit ($000s) | Project Benefit ($/MWh) | Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | ($000s) | ($/MWh) |
| 1 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 2 2002 | 1,902 | 1,902 | 26.5 | 7,338 | 5,435 | 75.6 | 3,472 | 148 | 3,619 | 50.3 | 5,522 | 76.8 |
| 3 2003 | 1,832 | 1,832 | 23.6 | 4,147 | 2,316 | 29.8 | 3,163 | 163 | 3,326 | 42.9 | 5,158 | 66.5 |
| 4 2004 | 1,762 | 1,762 | 23.2 | 2,816 | 1,053 | 13.9 | 3,015 | 164 | 3,179 | 41.9 | 4,941 | 65.1 |
| 5 2005 | 1,687 | 1,687 | 23.9 | 2,087 | 400 | 5.7 | 2,721 | 156 | 2,878 | 40.8 | 4,565 | 64.7 |
| 6 2006 | 1,613 | 1,613 | 26.0 | 1,385 | (228) | (3.7) | 2,400 | 141 | 2,541 | 40.9 | 4,154 | 66.9 |
| 7 2007 | 1,546 | 1,546 | 27.2 | 1,049 | (497) | (8.7) | 2,187 | 133 | 2,319 | 40.8 | 3,865 | 68.0 |
| 8 2008 | 1,481 | 1,481 | 19.5 | 1,782 | 300 | 4.0 | 1,931 | 182 | 2,113 | 27.9 | 3,594 | 47.4 |
| 9 2009 | 1,432 | 1,432 | 18.9 | 1,816 | 383 | 5.1 | 2,004 | 186 | 2,191 | 28.9 | 3,623 | 47.7 |
| 10 2010 | 1,385 | 1,385 | 18.1 | 1,880 | 495 | 6.5 | 2,097 | 193 | 2,290 | 29.9 | 3,675 | 48.0 |
| 11 2011 | 1,337 | 1,337 | 17.4 | 1,893 | 556 | 7.2 | 2,183 | 198 | 2,381 | 31.1 | 3,718 | 48.5 |
| 12 2012 | 1,290 | 1,290 | 16.9 | 2,117 | 827 | 10.8 | 2,265 | 203 | 2,468 | 32.3 | 3,758 | 49.2 |
| 13 2013 | 1,241 | 1,241 | 16.4 | 1,857 | 616 | 8.2 | 2,329 | 205 | 2,535 | 33.6 | 3,776 | 50.0 |
| 14 2014 | 1,194 | 1,194 | 15.8 | 1,894 | 700 | 9.3 | 2,426 | 211 | 2,637 | 35.0 | 3,831 | 50.8 |
| 15 2015 | 1,148 | 1,148 | 15.3 | 1,860 | 712 | 9.5 | 2,532 | 215 | 2,747 | 36.6 | 3,895 | 51.9 |
| 16 2016 | 1,101 | 1,101 | 14.7 | 1,844 | 742 | 9.9 | 2,636 | 220 | 2,856 | 38.2 | 3,957 | 52.9 |
| 17 2017 | 1,053 | 1,053 | 14.3 | 1,824 | 771 | 10.5 | 2,709 | 222 | 2,931 | 39.8 | 3,984 | 54.1 |
| 18 2018 | 1,005 | 1,005 | 13.7 | 1,824 | 819 | 11.2 | 2,793 | 227 | 3,020 | 41.3 | 4,025 | 55.0 |
| 19 2019 | 956 | 956 | 13.3 | 1,783 | 827 | 11.5 | 2,842 | 228 | 3,070 | 42.7 | 4,026 | 56.0 |
| 20 2020 | 905 | 905 | 13.0 | 2,094 | 1,189 | 17.0 | 2,870 | 227 | 3,097 | 44.4 | 4,002 | 57.4 |
| 21 2021 | 856 | 856 | 12.6 | 2,066 | 1,211 | 17.8 | 2,918 | 228 | 3,146 | 46.2 | 4,002 | 58.8 |
| 22 2022 | 811 | 811 | 12.2 | 2,035 | 1,224 | 18.4 | 2,958 | 228 | 3,186 | 48.0 | 3,997 | 60.2 |
| 23 2023 | 780 | 780 | 11.8 | 2,008 | 1,228 | 18.5 | 3,076 | 233 | 3,309 | 49.9 | 4,089 | 61.7 |
| 24 2024 | 752 | 752 | 11.5 | 2,009 | 1,257 | 19.2 | 3,175 | 236 | 3,412 | 52.1 | 4,164 | 63.6 |
| 25 2025 | 726 | 726 | 11.1 | 1,968 | 1,242 | 19.0 | 3,300 | 242 | 3,542 | 54.2 | 4,268 | 65.4 |
| *2001$* | | | | | | | | | | | | |
| Net Present Value | 14,120 | 14,120 | | 25,378 | 11,258 | | 26,334 | 1,835 | 28,170 | | 42,290 | |
| Nominal Levelized Cost ($/MWh) | | | 18.9 | | | 15.1 | | | | 37.7 | | 56.6 |
| Real Levelized Cost ($/MWh) | | | 14.8 | | | 11.8 | | | | 29.5 | | 44.3 |

# Kettle Falls Upgrade

## Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Installed Cost | 8,500 | $000s | Fixed Charge | 0.00 | per kW-month | Variable O&M | 2.00 | 2001$/MWh | Electric Wheeling Losses | 1.9 | percent |
| Project Capacity | 9.5 | MW | Fixed O&M | 0.00 | 2003$ per kW-month | | | | | | |
| Heat Rate | 8,750 | Btu/kWh | Escalation Rates | | | Insurance Cost | 0.0 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.8 | percent |
| Peak Gas Useage | 1,995 | 000s dth | Fixed O&M | 2.5 | percent | Gas Transport | 0.00 | 2000 $/dth | Real Discount Rate | 5.1 | percent |
| | | | Variable O&M | 2.5 | percent | Electric Wheeling | 0 | $/MW-month thru 2006 | | | |
| | | | Transportation | 2.0 | percent | General Inflation | 2.5 | percent | | | |

**Fixed Costs**

| | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 2 | 2002 | 63.3 | 1,506 | 0 | 1,506 | 23.8 | 0 | 0 | 0 | 116 | 0 | 116 | 1.8 |
| 3 | 2003 | 68.3 | 1,450 | 0 | 1,450 | 21.2 | 0 | 0 | 0 | 112 | 0 | 112 | 1.6 |
| 4 | 2004 | 66.7 | 1,394 | 0 | 1,394 | 20.9 | 0 | 0 | 0 | 108 | 0 | 108 | 1.6 |
| 5 | 2005 | 62.1 | 1,334 | 0 | 1,334 | 21.5 | 0 | 0 | 0 | 104 | 0 | 104 | 1.7 |
| 6 | 2006 | 54.7 | 1,275 | 0 | 1,275 | 23.3 | 0 | 0 | 0 | 100 | 0 | 100 | 1.8 |
| 7 | 2007 | 49.9 | 1,221 | 0 | 1,221 | 24.5 | 0 | 0 | 0 | 96 | 0 | 96 | 1.9 |
| 8 | 2008 | 66.8 | 1,170 | 0 | 1,170 | 17.5 | 0 | 0 | 0 | 92 | 0 | 92 | 1.4 |
| 9 | 2009 | 66.8 | 1,133 | 0 | 1,133 | 17.0 | 0 | 0 | 0 | 88 | 0 | 88 | 1.3 |
| 10 | 2010 | 67.4 | 1,097 | 0 | 1,097 | 16.3 | 0 | 0 | 0 | 84 | 0 | 84 | 1.2 |
| 11 | 2011 | 67.4 | 1,060 | 0 | 1,060 | 15.7 | 0 | 0 | 0 | 80 | 0 | 80 | 1.2 |
| 12 | 2012 | 67.2 | 1,024 | 0 | 1,024 | 15.2 | 0 | 0 | 0 | 76 | 0 | 76 | 1.1 |
| 13 | 2013 | 66.4 | 987 | 0 | 987 | 14.9 | 0 | 0 | 0 | 72 | 0 | 72 | 1.1 |
| 14 | 2014 | 66.3 | 951 | 0 | 951 | 14.3 | 0 | 0 | 0 | 68 | 0 | 68 | 1.0 |
| 15 | 2015 | 66.1 | 916 | 0 | 916 | 13.9 | 0 | 0 | 0 | 64 | 0 | 64 | 1.0 |
| 16 | 2016 | 65.8 | 880 | 0 | 880 | 13.4 | 0 | 0 | 0 | 60 | 0 | 60 | 0.9 |
| 17 | 2017 | 64.8 | 843 | 0 | 843 | 13.0 | 0 | 0 | 0 | 56 | 0 | 56 | 0.9 |
| 18 | 2018 | 64.4 | 807 | 0 | 807 | 12.5 | 0 | 0 | 0 | 52 | 0 | 52 | 0.8 |
| 19 | 2019 | 63.3 | 769 | 0 | 769 | 12.2 | 0 | 0 | 0 | 48 | 0 | 48 | 0.8 |
| 20 | 2020 | 61.5 | 730 | 0 | 730 | 11.9 | 0 | 0 | 0 | 44 | 0 | 44 | 0.7 |
| 21 | 2021 | 59.9 | 692 | 0 | 692 | 11.6 | 0 | 0 | 0 | 40 | 0 | 40 | 0.7 |
| 22 | 2022 | 58.4 | 658 | 0 | 658 | 11.3 | 0 | 0 | 0 | 36 | 0 | 36 | 0.6 |
| 23 | 2023 | 58.3 | 635 | 0 | 635 | 10.9 | 0 | 0 | 0 | 32 | 0 | 32 | 0.5 |
| 24 | 2024 | 57.6 | 616 | 0 | 616 | 10.7 | 0 | 0 | 0 | 28 | 0 | 28 | 0.5 |
| 25 | 2025 | 57.6 | 599 | 0 | 599 | 10.4 | 0 | 0 | 0 | 24 | 0 | 24 | 0.4 |
| *2001$* | | | | | | | | | | | | | |
| Net Present Value | | | 11,211 | 0 | 11,211 | | 0 | 0 | 0 | 832 | 0 | 832 | |
| Nominal Levelized Cost ($/MWh) | | | | | | 17.0 | | | | | | | 1.3 |
| Real Levelized Cost ($/MWh) | | | | | | 13.3 | | | | | | | 1.0 |

| | Year | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 2 | 2002 | 1,622 | 1,622 | 25.6 | 6,470 | 4,848 | 76.6 | 3,055 | 130 | 3,185 | 50.3 | 4,807 | 76.0 |
| 3 | 2003 | 1,562 | 1,562 | 22.9 | 3,678 | 2,116 | 31.0 | 2,783 | 144 | 2,927 | 42.9 | 4,489 | 65.7 |
| 4 | 2004 | 1,502 | 1,502 | 22.5 | 2,513 | 1,011 | 15.2 | 2,652 | 144 | 2,796 | 41.9 | 4,299 | 64.4 |
| 5 | 2005 | 1,438 | 1,438 | 23.2 | 1,868 | 430 | 6.9 | 2,393 | 138 | 2,531 | 40.8 | 3,969 | 63.9 |
| 6 | 2006 | 1,375 | 1,375 | 25.1 | 1,253 | (122) | (2.2) | 2,114 | 124 | 2,239 | 40.9 | 3,613 | 66.1 |
| 7 | 2007 | 1,317 | 1,317 | 26.4 | 955 | (362) | (7.2) | 1,920 | 116 | 2,037 | 40.8 | 3,354 | 67.2 |
| 8 | 2008 | 1,262 | 1,262 | 18.9 | 1,600 | 338 | 5.1 | 1,699 | 160 | 1,859 | 27.9 | 3,121 | 46.8 |
| 9 | 2009 | 1,220 | 1,220 | 18.3 | 1,631 | 411 | 6.1 | 1,764 | 164 | 1,928 | 28.9 | 3,148 | 47.1 |
| 10 | 2010 | 1,181 | 1,181 | 17.5 | 1,689 | 508 | 7.5 | 1,846 | 170 | 2,015 | 29.9 | 3,196 | 47.4 |
| 11 | 2011 | 1,140 | 1,140 | 16.9 | 1,700 | 559 | 8.3 | 1,920 | 174 | 2,095 | 31.1 | 3,235 | 48.0 |
| 12 | 2012 | 1,100 | 1,100 | 16.4 | 1,894 | 794 | 11.8 | 1,993 | 178 | 2,171 | 32.3 | 3,271 | 48.7 |
| 13 | 2013 | 1,059 | 1,059 | 15.9 | 1,671 | 612 | 9.2 | 2,049 | 181 | 2,230 | 33.6 | 3,289 | 49.5 |
| 14 | 2014 | 1,019 | 1,019 | 15.4 | 1,695 | 676 | 10.2 | 2,135 | 185 | 2,320 | 35.0 | 3,339 | 50.3 |
| 15 | 2015 | 980 | 980 | 14.8 | 1,671 | 692 | 10.5 | 2,228 | 189 | 2,417 | 36.6 | 3,397 | 51.4 |
| 16 | 2016 | 940 | 940 | 14.3 | 1,655 | 715 | 10.9 | 2,319 | 193 | 2,512 | 38.2 | 3,452 | 52.4 |
| 17 | 2017 | 899 | 899 | 13.9 | 1,638 | 739 | 11.4 | 2,384 | 195 | 2,580 | 39.8 | 3,479 | 53.7 |
| 18 | 2018 | 859 | 859 | 13.3 | 1,639 | 781 | 12.1 | 2,457 | 199 | 2,657 | 41.3 | 3,515 | 54.6 |
| 19 | 2019 | 817 | 817 | 12.9 | 1,602 | 785 | 12.4 | 2,500 | 201 | 2,701 | 42.7 | 3,518 | 55.6 |
| 20 | 2020 | 774 | 774 | 12.6 | 1,881 | 1,107 | 18.0 | 2,528 | 200 | 2,728 | 44.4 | 3,502 | 57.0 |
| 21 | 2021 | 732 | 732 | 12.2 | 1,851 | 1,119 | 18.7 | 2,565 | 200 | 2,765 | 46.2 | 3,497 | 58.4 |
| 22 | 2022 | 694 | 694 | 11.9 | 1,822 | 1,129 | 19.3 | 2,603 | 200 | 2,803 | 48.0 | 3,497 | 59.9 |
| 23 | 2023 | 667 | 667 | 11.4 | 1,796 | 1,129 | 19.4 | 2,708 | 205 | 2,913 | 49.9 | 3,580 | 61.4 |
| 24 | 2024 | 644 | 644 | 11.2 | 1,803 | 1,159 | 20.1 | 2,790 | 208 | 2,998 | 52.1 | 3,642 | 63.3 |
| 25 | 2025 | 623 | 623 | 10.8 | 1,768 | 1,145 | 19.9 | 2,909 | 213 | 3,122 | 54.3 | 3,745 | 65.1 |
| *2001$* | | | | | | | | | | | | | |
| Net Present Value | | 12,042 | 12,042 | | 22,643 | 10,601 | | 23,170 | 1,615 | 24,785 | | 36,828 | |
| Nominal Levelized Cost ($/MWh) | | | | 18.3 | | | 16.1 | | | | 37.7 | | 56.0 |
| Real Levelized Cost ($/MWh) | | | | 14.3 | | | 12.6 | | | | 29.5 | | 43.9 |

# Kettle Falls Upgrade

## Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Installed Cost | 6,500 | $000s | Fixed Charge | 0.00 | per kW-month | Variable O&M | 2.00 | 2001$/MWh |
| Project Capacity | 6.6 | MW | Fixed O&M | 0.00 | 2003$ per kW-month | | | |
| Heat Rate | 12,080 | Btu/kWh | Escalation Rates | | | Insurance Cost | 0.0 | 0.3% of installed cost ($000s) |
| Peak Gas Useage | 1,904 | 000s dth | Fixed O&M | 2.5 | percent | Gas Transport | 0.00 | 2000 $/dth |
| | | | Variable O&M | 2.5 | percent | Electric Wheeling | 0 | $/MW-month thru 2006 |
| | | | Transportation | 2.0 | percent | General Inflation | 2.5 | percent |

| | | |
|---|---|---|
| Electric Wheeling Losses | 1.9 | percent |
| Nominal Discount Rate | 7.8 | percent |
| Real Discount Rate | 5.1 | percent |

**Fixed Costs**

| | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 2 | 2002 | 47.8 | 1,193 | 0 | 1,193 | 24.9 | 0 | 0 | 0 | 89 | 0 | 89 | 1.9 |
| 3 | 2003 | 50.1 | 1,142 | 0 | 1,142 | 22.8 | 0 | 0 | 0 | 86 | 0 | 86 | 1.7 |
| 4 | 2004 | 44.5 | 1,086 | 0 | 1,086 | 24.4 | 0 | 0 | 0 | 82 | 0 | 82 | 1.9 |
| 5 | 2005 | 35.4 | 1,022 | 0 | 1,022 | 28.9 | 0 | 0 | 0 | 79 | 0 | 79 | 2.2 |
| 6 | 2006 | 21.1 | 949 | 0 | 949 | 45.1 | 0 | 0 | 0 | 76 | 0 | 76 | 3.6 |
| 7 | 2007 | 12.6 | 893 | 0 | 893 | 70.9 | 0 | 0 | 0 | 73 | 0 | 73 | 5.8 |
| 8 | 2008 | 22.6 | 866 | 0 | 866 | 38.4 | 0 | 0 | 0 | 70 | 0 | 70 | 3.1 |
| 9 | 2009 | 22.1 | 836 | 0 | 836 | 37.7 | 0 | 0 | 0 | 67 | 0 | 67 | 3.0 |
| 10 | 2010 | 23.7 | 809 | 0 | 809 | 34.2 | 0 | 0 | 0 | 64 | 0 | 64 | 2.7 |
| 11 | 2011 | 23.1 | 779 | 0 | 779 | 33.8 | 0 | 0 | 0 | 61 | 0 | 61 | 2.6 |
| 12 | 2012 | 23.2 | 751 | 0 | 751 | 32.3 | 0 | 0 | 0 | 58 | 0 | 58 | 2.5 |
| 13 | 2013 | 22.3 | 720 | 0 | 720 | 32.2 | 0 | 0 | 0 | 55 | 0 | 55 | 2.5 |
| 14 | 2014 | 21.2 | 689 | 0 | 689 | 32.6 | 0 | 0 | 0 | 52 | 0 | 52 | 2.5 |
| 15 | 2015 | 20.8 | 660 | 0 | 660 | 31.7 | 0 | 0 | 0 | 49 | 0 | 49 | 2.3 |
| 16 | 2016 | 20.7 | 631 | 0 | 631 | 30.4 | 0 | 0 | 0 | 46 | 0 | 46 | 2.2 |
| 17 | 2017 | 20.7 | 602 | 0 | 602 | 29.1 | 0 | 0 | 0 | 43 | 0 | 43 | 2.1 |
| 18 | 2018 | 20.0 | 572 | 0 | 572 | 28.5 | 0 | 0 | 0 | 40 | 0 | 40 | 2.0 |
| 19 | 2019 | 19.7 | 543 | 0 | 543 | 27.5 | 0 | 0 | 0 | 37 | 0 | 37 | 1.9 |
| 20 | 2020 | 20.6 | 516 | 0 | 516 | 25.1 | 0 | 0 | 0 | 34 | 0 | 34 | 1.6 |
| 21 | 2021 | 19.6 | 484 | 0 | 484 | 24.7 | 0 | 0 | 0 | 31 | 0 | 31 | 1.6 |
| 22 | 2022 | 18.6 | 455 | 0 | 455 | 24.5 | 0 | 0 | 0 | 27 | 0 | 27 | 1.5 |
| 23 | 2023 | 18.0 | 434 | 0 | 434 | 24.2 | 0 | 0 | 0 | 24 | 0 | 24 | 1.4 |
| 24 | 2024 | 16.6 | 414 | 0 | 414 | 25.0 | 0 | 0 | 0 | 21 | 0 | 21 | 1.3 |
| 25 | 2025 | 16.1 | 397 | 0 | 397 | 24.6 | 0 | 0 | 0 | 18 | 0 | 18 | 1.1 |
| *2001$* | | | | | | | | | | | | | |
| Net Present Value | | | 8,394 | 0 | 8,394 | | 0 | 0 | 0 | 636 | 0 | 636 | |
| Nominal Levelized Cost ($/MWh) | | | | | | 33.2 | | | | | | | 2.5 |
| Real Levelized Cost ($/MWh) | | | | | | 26.0 | | | | | | | 2.0 |

| | Year | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 2 | 2002 | 1,281 | 1,281 | 26.8 | 4,038 | 2,757 | 57.6 | 3,192 | 98 | 3,290 | 68.8 | 4,572 | 95.6 |
| 3 | 2003 | 1,227 | 1,227 | 24.5 | 2,194 | 966 | 19.3 | 2,822 | 105 | 2,927 | 58.5 | 4,155 | 83.0 |
| 4 | 2004 | 1,168 | 1,168 | 26.3 | 1,255 | 87 | 1.9 | 2,448 | 96 | 2,545 | 57.2 | 3,713 | 83.5 |
| 5 | 2005 | 1,101 | 1,101 | 31.1 | 872 | (229) | (6.5) | 1,886 | 78 | 1,964 | 55.5 | 3,066 | 86.6 |
| 6 | 2006 | 1,025 | 1,025 | 48.7 | 533 | (492) | (23.4) | 1,121 | 48 | 1,169 | 55.5 | 2,194 | 104.2 |
| 7 | 2007 | 966 | 966 | 76.7 | 416 | (550) | (43.7) | 671 | 29 | 701 | 55.6 | 1,667 | 132.3 |
| 8 | 2008 | 937 | 937 | 41.5 | 853 | (83) | (3.7) | 772 | 54 | 826 | 36.6 | 1,763 | 78.1 |
| 9 | 2009 | 903 | 903 | 40.8 | 862 | (41) | (1.8) | 786 | 54 | 840 | 38.0 | 1,743 | 78.7 |
| 10 | 2010 | 874 | 874 | 36.9 | 888 | 14 | 0.6 | 871 | 60 | 931 | 39.3 | 1,804 | 76.2 |
| 11 | 2011 | 840 | 840 | 36.4 | 880 | 39 | 1.7 | 882 | 60 | 941 | 40.8 | 1,782 | 77.3 |
| 12 | 2012 | 809 | 809 | 34.8 | 1,013 | 204 | 8.8 | 923 | 62 | 984 | 42.4 | 1,793 | 77.3 |
| 13 | 2013 | 775 | 775 | 34.7 | 838 | 63 | 2.8 | 925 | 61 | 986 | 44.2 | 1,761 | 78.9 |
| 14 | 2014 | 741 | 741 | 35.0 | 845 | 104 | 4.9 | 918 | 59 | 977 | 46.2 | 1,718 | 81.2 |
| 15 | 2015 | 709 | 709 | 34.0 | 820 | 111 | 5.3 | 947 | 60 | 1,007 | 48.3 | 1,715 | 82.4 |
| 16 | 2016 | 677 | 677 | 32.7 | 795 | 118 | 5.7 | 985 | 61 | 1,046 | 50.5 | 1,723 | 83.1 |
| 17 | 2017 | 645 | 645 | 31.2 | 781 | 136 | 6.6 | 1,025 | 62 | 1,087 | 52.5 | 1,732 | 83.7 |
| 18 | 2018 | 612 | 612 | 30.5 | 775 | 163 | 8.1 | 1,031 | 62 | 1,093 | 54.5 | 1,705 | 85.1 |
| 19 | 2019 | 579 | 579 | 29.4 | 734 | 155 | 7.9 | 1,053 | 63 | 1,116 | 56.6 | 1,695 | 85.9 |
| 20 | 2020 | 549 | 549 | 26.7 | 920 | 371 | 18.1 | 1,125 | 67 | 1,192 | 58.0 | 1,741 | 84.7 |
| 21 | 2021 | 515 | 515 | 26.2 | 901 | 386 | 19.7 | 1,111 | 66 | 1,177 | 59.9 | 1,692 | 86.1 |
| 22 | 2022 | 483 | 483 | 26.0 | 884 | 401 | 21.6 | 1,083 | 64 | 1,147 | 61.8 | 1,630 | 87.8 |
| 23 | 2023 | 459 | 459 | 25.5 | 862 | 403 | 22.4 | 1,089 | 63 | 1,153 | 64.1 | 1,611 | 89.6 |
| 24 | 2024 | 435 | 435 | 26.3 | 859 | 424 | 25.6 | 1,039 | 60 | 1,098 | 66.3 | 1,534 | 92.6 |
| 25 | 2025 | 415 | 415 | 25.7 | 840 | 425 | 26.4 | 1,051 | 60 | 1,110 | 68.9 | 1,525 | 94.6 |
| *2001$* | | | | | | | | | | | | | |
| Net Present Value | | 9,030 | 9,030 | | 12,181 | 3,151 | | 14,537 | 680 | 15,217 | | 24,247 | |
| Nominal Levelized Cost ($/MWh) | | | | 35.7 | | | 12.5 | | | | 60.1 | | 95.8 |
| Real Levelized Cost ($/MWh) | | | | 28.0 | | | 9.8 | | | | 47.1 | | 75.1 |

**AVISTA Corp.**

*Interoffice Memorandum*
*Resource Optimization*

**DATE:** September 12, 2001

**TO:** Ed Groce

**FROM:** Clint Kalich CK

**SUBJECT:** Re-visit of Kettle Falls CT

Per your request, following are revised economic analyses on the Kettle Falls CT. It is important here to recognize the work of Steve Silkworth, as he provided the initial economic models used. Without his efforts, I would expect this memo to take a number of additional days to generate.

Project completion, according to Tomas Dempsey, will cost $1.7 million. Although an exact figure of expenses to date was not provided, you likely recall an initial estimate of $8.5 million for the entire project. Given this assumption, just under $7 million already has been spent, ~~to date~~ or committed to be spent, on the project.

To evaluate the CT project, two scenarios were performed: 1) combined-cycle operation with the existing Kettle Falls boiler and 2) simple-cycle operation. The attached spreadsheets explain that operating in simple-cycle the new CT would generate losses of approximately $250,000 on expenses of $400,000, per year. The project would generate losses through 2013 and thereafter add positive margins to the Company. Over the 24-year analysis, the net present value of the investment is a loss of $856,000 (2001$). On a per-unit basis, the nominal levelized loss is $6.3 per MWh (2001$).

In combined-cycle, the new CT project generates a positive net present value of nearly $4 million (2001$) over 24 years, or $6.7 per MWh nominal levelized. However, the project does not provide positive cash flow until 2008, losing in the earlier years on average about $90,000 on project costs of $1.0 million annually. Additionally, analyzing the CT as a combined-cycle unit presents a very optimistic picture. Given the plant's heat rate, it is likely that at most times it will not be the least-cost option to run the turbine to add heat to the Kettle Falls boiler. With gas at more than $3 per decatherm, the plant's nearly 9,000 combined-cycle heat rate puts generation at over $25 per MWh.

If you need some additional information or analysis, please give me a call.

attachments

Cc: Lloyd Meyers, Steve Wenke, Steve Silkworth

KF CT Study 09/11/01

These values were given to me from Thomas Dempsey on 9/11/01 for the Kettle Falls CT. This option burns natural gas in simple cycle
and diverts waste heat in a feedwater heater in the existing Kettle Falls boiler for heat recovery.

Heat Rate = 8845 kW/Btu (Higher Heating Value)
Capacity = 7072 kW (SCCT) + 3030 kW (Heat Recovery) = 10,102 kW
Capital required to complete the project = $1,700,000

# Kettle Falls SCCT -- Heat Recovery in Kettle Falls Boiler

## Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Installed Cost | 1,700 | $000s | Fixed Charge | 0.00 | per kW-month | Variable O&M | 2.00 | 2001$/MWh | Electric Wheeling Losses | 1.9 | percent |
| Project Capacity | 10.1 | MW | Fixed O&M | 0.00 | 2003$ per kW-month | | | | | | |
| Heat Rate | 8,845 | Btu/kWh | Escalation Rates | | | Insurance Cost | 0.0 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.8 | percent |
| Peak Gas Useage | 2,144 | 000s dth | Fixed O&M | 2.5 | percent | Gas Transport | 0.00 | 2000 $/dth | Real Discount Rate | 5.1 | percent |
| | | | Variable O&M | 2.5 | percent | Electric Wheeling | 0 | $/MW-month thru 2006 | | | |
| | | | Transportation | 2.0 | percent | General Inflation | 2.5 | percent | | | |

Profitability Index: 2.31598

**Fixed Costs**

| | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 2 | 2002 | 22.3 | 306 | 0 | 306 | 13.7 | 0 | 0 | 0 | 23 | 0 | 23 | 1.0 |
| 3 | 2003 | 19.4 | 293 | 0 | 293 | 15.1 | 0 | 0 | 0 | 22 | 0 | 22 | 1.2 |
| 4 | 2004 | 23.4 | 290 | 0 | 290 | 12.4 | 0 | 0 | 0 | 22 | 0 | 22 | 0.9 |
| 5 | 2005 | 30.2 | 290 | 0 | 290 | 9.6 | 0 | 0 | 0 | 21 | 0 | 21 | 0.7 |
| 6 | 2006 | 23.1 | 269 | 0 | 269 | 11.7 | 0 | 0 | 0 | 20 | 0 | 20 | 0.9 |
| 7 | 2007 | 30.2 | 271 | 0 | 271 | 9.0 | 0 | 0 | 0 | 19 | 0 | 19 | 0.6 |
| 8 | 2008 | 40.2 | 276 | 0 | 276 | 6.9 | 0 | 0 | 0 | 18 | 0 | 18 | 0.5 |
| 9 | 2009 | 45.0 | 273 | 0 | 273 | 6.1 | 0 | 0 | 0 | 18 | 0 | 18 | 0.4 |
| 10 | 2010 | 45.0 | 267 | 0 | 267 | 5.9 | 0 | 0 | 0 | 17 | 0 | 17 | 0.4 |
| 11 | 2011 | 45.0 | 262 | 0 | 262 | 5.8 | 0 | 0 | 0 | 16 | 0 | 16 | 0.4 |
| 12 | 2012 | 45.3 | 257 | 0 | 257 | 5.7 | 0 | 0 | 0 | 15 | 0 | 15 | 0.3 |
| 13 | 2013 | 45.0 | 251 | 0 | 251 | 5.6 | 0 | 0 | 0 | 14 | 0 | 14 | 0.3 |
| 14 | 2014 | 81.1 | 313 | 0 | 313 | 3.9 | 0 | 0 | 0 | 14 | 0 | 14 | 0.2 |
| 15 | 2015 | 80.9 | 311 | 0 | 311 | 3.8 | 0 | 0 | 0 | 13 | 0 | 13 | 0.2 |
| 16 | 2016 | 81.2 | 309 | 0 | 309 | 3.8 | 0 | 0 | 0 | 12 | 0 | 12 | 0.1 |
| 17 | 2017 | 77.9 | 300 | 0 | 300 | 3.8 | 0 | 0 | 0 | 11 | 0 | 11 | 0.1 |
| 18 | 2018 | 78.1 | 297 | 0 | 297 | 3.8 | 0 | 0 | 0 | 10 | 0 | 10 | 0.1 |
| 19 | 2019 | 75.2 | 288 | 0 | 288 | 3.8 | 0 | 0 | 0 | 10 | 0 | 10 | 0.1 |
| 20 | 2020 | 75.2 | 284 | 0 | 284 | 3.8 | 0 | 0 | 0 | 9 | 0 | 9 | 0.1 |
| 21 | 2021 | 74.9 | 279 | 0 | 279 | 3.7 | 0 | 0 | 0 | 8 | 0 | 8 | 0.1 |
| 22 | 2022 | 74.9 | 276 | 0 | 276 | 3.7 | 0 | 0 | 0 | 7 | 0 | 7 | 0.1 |
| 23 | 2023 | 77.9 | 281 | 0 | 281 | 3.6 | 0 | 0 | 0 | 6 | 0 | 6 | 0.1 |
| 24 | 2024 | 78.3 | 282 | 0 | 282 | 3.6 | 0 | 0 | 0 | 6 | 0 | 6 | 0.1 |
| 25 | 2025 | 78.1 | 281 | 0 | 281 | 3.6 | 0 | 0 | 0 | 5 | 0 | 5 | 0.1 |
| 2001$ | | | | | | | | | | | | | |
| Net Present Value | | | 2,826 | 0 | 2,826 | | 0 | 0 | 0 | 166 | 0 | 166 | |
| Nominal Levelized Cost ($/MWh) | | | | | | 4.8 | | | | | | | 0.3 |
| Real Levelized Cost ($/MWh) | | | | | | 3.8 | | | | | | | 0.2 |

| | Year | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 2 | 2002 | 329 | 329 | 14.7 | 246 | (83) | (3.7) | 681 | 45 | 726 | 32.5 | 1,055 | 47.2 |
| 3 | 2003 | 316 | 316 | 16.2 | 200 | (116) | (6.0) | 613 | 39 | 652 | 33.6 | 967 | 49.8 |
| 4 | 2004 | 311 | 311 | 13.3 | 208 | (103) | (4.4) | 742 | 47 | 789 | 33.7 | 1,101 | 47.0 |
| 5 | 2005 | 311 | 311 | 10.3 | 244 | (67) | (2.2) | 937 | 60 | 997 | 33.1 | 1,309 | 43.4 |
| 6 | 2006 | 289 | 289 | 12.5 | 202 | (87) | (3.8) | 701 | 46 | 747 | 32.3 | 1,036 | 44.9 |
| 7 | 2007 | 290 | 290 | 9.6 | 277 | (13) | (0.4) | 902 | 60 | 962 | 31.9 | 1,252 | 41.5 |
| 8 | 2008 | 295 | 295 | 7.3 | 359 | 64 | 1.6 | 1,171 | 80 | 1,251 | 31.2 | 1,546 | 38.5 |
| 9 | 2009 | 291 | 291 | 6.5 | 467 | 176 | 3.9 | 1,269 | 90 | 1,359 | 30.2 | 1,650 | 36.7 |
| 10 | 2010 | 284 | 284 | 6.3 | 494 | 210 | 4.7 | 1,313 | 90 | 1,403 | 31.2 | 1,687 | 37.5 |
| 11 | 2011 | 278 | 278 | 6.2 | 502 | 224 | 5.0 | 1,363 | 90 | 1,453 | 32.3 | 1,730 | 38.5 |
| 12 | 2012 | 272 | 272 | 6.0 | 507 | 235 | 5.2 | 1,426 | 91 | 1,516 | 33.5 | 1,788 | 39.5 |
| 13 | 2013 | 265 | 265 | 5.9 | 514 | 249 | 5.5 | 1,472 | 90 | 1,562 | 34.7 | 1,827 | 40.6 |
| 14 | 2014 | 326 | 326 | 4.0 | 1,522 | 1,196 | 14.7 | 2,857 | 162 | 3,019 | 37.2 | 3,346 | 41.3 |
| 15 | 2015 | 323 | 323 | 4.0 | 1,488 | 1,165 | 14.4 | 2,985 | 162 | 3,147 | 38.9 | 3,470 | 42.9 |
| 16 | 2016 | 321 | 321 | 4.0 | 1,464 | 1,143 | 14.1 | 3,123 | 162 | 3,286 | 40.5 | 3,607 | 44.4 |
| 17 | 2017 | 311 | 311 | 4.0 | 1,432 | 1,121 | 14.4 | 3,096 | 156 | 3,252 | 41.7 | 3,563 | 45.7 |
| 18 | 2018 | 308 | 308 | 3.9 | 1,415 | 1,107 | 14.2 | 3,216 | 156 | 3,372 | 43.2 | 3,680 | 47.1 |
| 19 | 2019 | 298 | 298 | 4.0 | 1,452 | 1,155 | 15.4 | 3,193 | 150 | 3,344 | 44.5 | 3,641 | 48.4 |
| 20 | 2020 | 293 | 293 | 3.9 | 1,495 | 1,203 | 16.0 | 3,277 | 150 | 3,427 | 45.6 | 3,720 | 49.4 |
| 21 | 2021 | 287 | 287 | 3.8 | 1,534 | 1,247 | 16.7 | 3,340 | 150 | 3,490 | 46.6 | 3,777 | 50.5 |
| 22 | 2022 | 283 | 283 | 3.8 | 1,575 | 1,292 | 17.3 | 3,423 | 150 | 3,573 | 47.7 | 3,856 | 51.5 |
| 23 | 2023 | 288 | 288 | 3.7 | 1,621 | 1,334 | 17.1 | 3,647 | 156 | 3,803 | 48.8 | 4,091 | 52.5 |
| 24 | 2024 | 288 | 288 | 3.7 | 1,671 | 1,383 | 17.7 | 3,759 | 157 | 3,915 | 50.0 | 4,203 | 53.7 |
| 25 | 2025 | 286 | 286 | 3.7 | 1,716 | 1,430 | 18.3 | 3,842 | 156 | 3,998 | 51.2 | 4,284 | 54.9 |
| 2001$ | | | | | | | | | | | | | |
| Net Present Value | | 2,993 | 2,993 | | 6,646 | 3,937 | | 16,247 | 905 | 17,152 | | 20,144 | |
| Nominal Levelized Cost ($/MWh) | | | | 5.1 | | | 6.7 | | | | 29.2 | | 34.3 |
| Real Levelized Cost ($/MWh) | | | | 4.0 | | | 5.3 | | | | 22.9 | | 26.9 |

# Kettle Falls SCCT -- Simple Cycle Only

## Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Installed Cost | 1,700 | $000s | Fixed Charge | 0.00 | per kW-month | Variable O&M | 2.00 | 
| Project Capacity | 6.6 | MW | Fixed O&M | 0.00 | 2003$ per kW-month | | |
| Heat Rate | 12,080 | Btu/kWh | Escalation Rates | | | Insurance Cost | 0.0 |
| Peak Gas Useage | 1,913 | 000s dth | Fixed O&M | 2.5 | percent | Gas Transport | 0.00 |
| | | | Variable O&M | 2.5 | percent | Electric Wheeling | 0 |
| | | | Transportation | 2.0 | percent | General Inflation | 2.5 |

| | | | | |
|---|---|---|---|---|
| Variable O&M | 2.00 | 2001$/MWh | Electric Wheeling Losses | 1.9 percent |
| Insurance Cost | 0.0 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.8 percent |
| Gas Transport | 0.00 | 2000 $/dth | Real Discount Rate | 5.1 percent |
| Electric Wheeling | 0 | $/MW-month thru 2006 | | |
| General Inflation | 2.5 | percent | | |

Profitability Index: -0.50380

**Fixed Costs**

| | | | Capital Recovery and Miscellaneous | | | | Operations & Maintenance | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Energy (GWh) | Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
| 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 2 | 2002 | 2.7 | 276 | 0 | 276 | 102.0 | 0 | 0 | 0 | 23 | 0 | 23 | 8.6 |
| 3 | 2003 | 2.6 | 267 | 0 | 267 | 102.5 | 0 | 0 | 0 | 22 | 0 | 22 | 8.6 |
| 4 | 2004 | 2.6 | 258 | 0 | 258 | 98.8 | 0 | 0 | 0 | 22 | 0 | 22 | 8.3 |
| 5 | 2005 | 2.7 | 248 | 0 | 248 | 91.7 | 0 | 0 | 0 | 21 | 0 | 21 | 7.7 |
| 6 | 2006 | 2.7 | 239 | 0 | 239 | 88.3 | 0 | 0 | 0 | 20 | 0 | 20 | 7.4 |
| 7 | 2007 | 2.7 | 230 | 0 | 230 | 85.0 | 0 | 0 | 0 | 19 | 0 | 19 | 7.1 |
| 8 | 2008 | 7.3 | 231 | 0 | 231 | 31.7 | 0 | 0 | 0 | 18 | 0 | 18 | 2.5 |
| 9 | 2009 | 7.3 | 221 | 0 | 221 | 30.3 | 0 | 0 | 0 | 18 | 0 | 18 | 2.4 |
| 10 | 2010 | 10.0 | 218 | 0 | 218 | 21.9 | 0 | 0 | 0 | 17 | 0 | 17 | 1.7 |
| 11 | 2011 | 7.3 | 206 | 0 | 206 | 28.3 | 0 | 0 | 0 | 16 | 0 | 16 | 2.2 |
| 12 | 2012 | 7.2 | 198 | 0 | 198 | 27.6 | 0 | 0 | 0 | 15 | 0 | 15 | 2.1 |
| 13 | 2013 | 7.2 | 190 | 0 | 190 | 26.5 | 0 | 0 | 0 | 14 | 0 | 14 | 2.0 |
| 14 | 2014 | 22.4 | 220 | 0 | 220 | 9.9 | 0 | 0 | 0 | 14 | 0 | 14 | 0.6 |
| 15 | 2015 | 22.5 | 215 | 0 | 215 | 9.6 | 0 | 0 | 0 | 13 | 0 | 13 | 0.6 |
| 16 | 2016 | 22.5 | 209 | 0 | 209 | 9.3 | 0 | 0 | 0 | 12 | 0 | 12 | 0.5 |
| 17 | 2017 | 22.4 | 203 | 0 | 203 | 9.1 | 0 | 0 | 0 | 11 | 0 | 11 | 0.5 |
| 18 | 2018 | 19.8 | 190 | 0 | 190 | 9.6 | 0 | 0 | 0 | 10 | 0 | 10 | 0.5 |
| 19 | 2019 | 19.8 | 184 | 0 | 184 | 9.3 | 0 | 0 | 0 | 10 | 0 | 10 | 0.5 |
| 20 | 2020 | 19.9 | 177 | 0 | 177 | 8.9 | 0 | 0 | 0 | 9 | 0 | 9 | 0.4 |
| 21 | 2021 | 19.9 | 171 | 0 | 171 | 8.6 | 0 | 0 | 0 | 8 | 0 | 8 | 0.4 |
| 22 | 2022 | 19.9 | 165 | 0 | 165 | 8.3 | 0 | 0 | 0 | 7 | 0 | 7 | 0.4 |
| 23 | 2023 | 19.8 | 161 | 0 | 161 | 8.1 | 0 | 0 | 0 | 6 | 0 | 6 | 0.3 |
| 24 | 2024 | 19.8 | 157 | 0 | 157 | 8.0 | 0 | 0 | 0 | 6 | 0 | 6 | 0.3 |
| 25 | 2025 | 19.9 | 155 | 0 | 155 | 7.8 | 0 | 0 | 0 | 5 | 0 | 5 | 0.2 |
| *2001$* | | | | | | | | | | | | | |
| Net Present Value | | | 2,235 | 0 | 2,235 | | 0 | 0 | 0 | 166 | 0 | 166 | |
| Nominal Levelized Cost ($/MWh) | | | | | | 16.5 | | | | | | | 1.2 |
| Real Levelized Cost ($/MWh) | | | | | | 13.0 | | | | | | | 1.0 |

| | | Total Fixed Costs | | | Less | Net | | Variable Costs | | | | Total Project Cost after Credits | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Operating Margin ($000s) | Project Benefit ($000s) | Project Benefit ($/MWh) | Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | ($000s) | ($/MWh) |
| 1 | 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 2 | 2002 | 299 | 299 | 110.6 | 28 | (271) | (100.2) | 110 | 5 | 116 | 42.7 | 415 | 153.2 |
| 3 | 2003 | 290 | 290 | 111.1 | 21 | (268) | (102.9) | 109 | 5 | 114 | 43.7 | 404 | 154.8 |
| 4 | 2004 | 279 | 279 | 107.0 | 20 | (259) | (99.3) | 110 | 5 | 115 | 44.3 | 395 | 151.3 |
| 5 | 2005 | 269 | 269 | 99.3 | 24 | (245) | (90.6) | 112 | 5 | 118 | 43.5 | 387 | 142.8 |
| 6 | 2006 | 259 | 259 | 95.6 | 20 | (239) | (88.2) | 110 | 5 | 116 | 42.7 | 375 | 138.3 |
| 7 | 2007 | 249 | 249 | 92.1 | 28 | (222) | (81.9) | 108 | 5 | 113 | 41.9 | 363 | 133.9 |
| 8 | 2008 | 249 | 249 | 34.2 | 48 | (201) | (27.6) | 285 | 15 | 300 | 41.2 | 548 | 75.4 |
| 9 | 2009 | 238 | 238 | 32.8 | 98 | (140) | (19.2) | 249 | 15 | 263 | 36.2 | 501 | 68.9 |
| 10 | 2010 | 235 | 235 | 23.6 | 110 | (125) | (12.6) | 366 | 20 | 386 | 38.6 | 621 | 62.2 |
| 11 | 2011 | 221 | 221 | 30.5 | 107 | (115) | (15.8) | 267 | 15 | 282 | 38.7 | 503 | 69.2 |
| 12 | 2012 | 213 | 213 | 29.7 | 107 | (106) | (14.8) | 274 | 14 | 288 | 40.2 | 501 | 69.9 |
| 13 | 2013 | 205 | 205 | 28.5 | 108 | (97) | (13.5) | 284 | 14 | 299 | 41.7 | 503 | 70.2 |
| 14 | 2014 | 234 | 234 | 10.5 | 477 | 243 | 10.9 | 1,052 | 45 | 1,097 | 49.0 | 1,331 | 59.5 |
| 15 | 2015 | 228 | 228 | 10.1 | 450 | 222 | 9.9 | 1,106 | 45 | 1,151 | 51.2 | 1,379 | 61.3 |
| 16 | 2016 | 221 | 221 | 9.9 | 424 | 202 | 9.0 | 1,154 | 45 | 1,199 | 53.4 | 1,421 | 63.2 |
| 17 | 2017 | 215 | 215 | 9.6 | 402 | 188 | 8.4 | 1,197 | 45 | 1,242 | 55.5 | 1,456 | 65.1 |
| 18 | 2018 | 201 | 201 | 10.2 | 389 | 188 | 9.5 | 1,099 | 40 | 1,139 | 57.6 | 1,340 | 67.8 |
| 19 | 2019 | 193 | 193 | 9.8 | 401 | 208 | 10.5 | 1,127 | 40 | 1,166 | 59.0 | 1,360 | 68.8 |
| 20 | 2020 | 186 | 186 | 9.4 | 412 | 226 | 11.4 | 1,161 | 40 | 1,201 | 60.4 | 1,387 | 69.8 |
| 21 | 2021 | 179 | 179 | 9.0 | 423 | 244 | 12.3 | 1,191 | 40 | 1,230 | 61.9 | 1,409 | 70.9 |
| 22 | 2022 | 172 | 172 | 8.7 | 434 | 262 | 13.2 | 1,220 | 40 | 1,260 | 63.4 | 1,432 | 72.1 |
| 23 | 2023 | 167 | 167 | 8.5 | 446 | 279 | 14.1 | 1,243 | 40 | 1,283 | 64.9 | 1,450 | 73.4 |
| 24 | 2024 | 163 | 163 | 8.3 | 459 | 296 | 15.0 | 1,275 | 40 | 1,315 | 66.5 | 1,478 | 74.8 |
| 25 | 2025 | 159 | 159 | 8.0 | 472 | 312 | 15.7 | 1,314 | 40 | 1,353 | 68.1 | 1,513 | 76.2 |
| *2001$* | | | | | | | | | | | | | |
| Net Present Value | | 2,401 | 2,401 | | 1,606 | (856) | | 4,618 | 186 | 4,804 | | 7,205 | |
| Nominal Levelized Cost ($/MWh) | | | | 17.8 | | | (6.3) | | | | 35.5 | | 53.3 |
| Real Levelized Cost ($/MWh) | | | | 13.9 | | | (5.0) | | | | 27.8 | | 41.8 |

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-C24)

CONFIDENTIAL

**AVISTA® Corp.**

***Interoffice Memorandum***
***Resource Optimization***

**DATE:** November 16, 2001

**TO:** File

**FROM:** Clint Kalich, Manager of Power Supply Analysis

**SUBJECT:** October Re-Evaluation of Coyote Springs II Alternatives

During October I evaluated purchase proposals from Enron and PG&E National Energy Group to assist in determining their feasibility when compared to full ownership of the CSII project. I updated the base assumptions for full Avista ownership in light of significant changes in the electricity marketplace since the original evaluations were completed nearly one year ago.

Based on a meeting in which Lloyd Meyers, Kelly Norwood, Dick Storro, Bob Lafferty and I reached consensus on the appropriate market price forecast to use in evaluating these alternatives, new analyses were run using the November 2000 R.W. Beck price forecast for the years 2003 through 2022. The Company's forward curve for 2002 was used in that year. The expectation was that the relative economics of the alternatives wouldn't change with the longer-term price estimates. This assumption proved correct.

Each of the offers discussed below used the market prices discussed above in paragraph 2, and contained the same underlying market assumptions, including forward curves for natural gas and electricity. The result was that the PG&E and Enron proposals both were significantly less attractive than a 50/50 ownership between Avista and Mirant. A summary of the offers is contained in the following table.

**Coyote Springs Alternatives**

| Alternative | Net Present Value ($millions) | Project Capability (MW) | NPV (millions) per MW |
|---|---|---|---|
| Full Ownership | 70.6 | 280 | 0.25 |
| 50% Sale to Mirant | 35.0 | 140 | 0.25 |
| Enron Toll | 26.9 | 280 | 0.10 |
| PG&E Toll | (100.2) | 280 | (0.36) |

As the table explains, on a per-MW basis, Full Ownership and a 50% Sale to Mirant generate equal and the greatest NPV/MW value after accounting for capital recovery costs. The Enron offer generated approximately 40 percent of the value of full and 50% ownership. The PG&E offer was not able to generate a positive value for customers.

Supporting documents are attached to this memorandum to detail the specifics of the offers made; included are the offers and economic analysis worksheets.

*Base Case CSII Costs*

Updating the CSII project economics shows the plant to be in the money by $70.6 million on a 20-year NPV basis ($2002) on total costs of $854 million.

*PG&E National Energy Group Tolling Proposal*

The PG&E offer included a full purchase ($190 million) of the plant from Avista in exchange for a $9.75/kW-month (2% annual escalation) 20-year tolling contract. Under the arrangement, Avista would be responsible for all O&M and fuel costs, essentially keeping the operating costs of the plant equal to what they would be where the company still owned it.

On a 20-year NPV basis ($2002), the PG&E offer was out of the money by $100.2 million on $1.0 billion in total costs. This difference from the base case was driven by an increase in the capital recovery and fixed O&M costs from $418 million to $577 million, mostly due to the escalation factor on the tolling rate of $9.75/kW-month.

The PG&E offer was not attractive from an economic perspective, as costs were $171 million higher on a 20-year NPV ($2002).

*Enron Tolling Offer*

Enron in late September made an offer that worked essentially in the same manner as that of PG&E. In early October the offer was updated. In exchange for purchasing CSII at cost, Avista would enter into a 20-year tolling arrangement with Enron. The only key difference was the base fixed capacity price of $8.08/kW-month. Enron did provide some specific heat rate and O&M pricing information, but indicated that they expected that all costs would be passed back through to Avista if they differed greatly from the proposal.

On a 20-year NPV basis, the Enron proposal is significantly more attractive than the PG&E offer, primarily because the capacity payment is lower and does not escalate over time. The Enron offer has a positive 20-year NPV ($2002) of $26.9 million.

*Mirant 50% Ownership Offer*

Mirant in October offered a 50 percent ownership arrangement whereby Avista and Mirant would share equally in the project costs and generation. Therefore, all costs and revenues to Avista a cut in half. The 20-year NPV ($2002) falls from $70.6 million to 35.0 million. However, as the NPV/MW ratio explains, the original value of the plant is retained in the Mirant offer. Avista receives a smaller portion of the project's benefits in exchange for investing less in the plant.

cc: w/attachments
Meyers, Groce, Lafferty, Storro

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# Coyote Springs 2 - UPDATE ANALYSIS

## Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Installed Cost | 187,867 | $000s | Fixed Charge | 0.00 | per kW-month | | | | | | |
| Project Capacity | 280.0 | MW | Fixed O&M | 1.75 | 2002$ per kW-month | | | | | | |
| Heat Rate | 7,090 | Btu/kWh | Escalation Rates | | | Insurance Cost | 563.6 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.8 | percent |
| Gas Usage Rate | 47.6 | 000s dth/day | Fixed O&M | 2.6 | percent | Gas Transport | 0.38760 | 2001 $/dth/day | Real Discount Rate | 5.0 | percent |
| | | | Variable O&M | 2.6 | percent | Electric Wheeling | 1,243 | $/MW-month thru 2006 | | | |
| | | | Transportation | 2.0 | percent | General Inflation | 2.6 | percent | | | |

**Fixed Costs**

| Year | | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 2 | 2002 | 1,161.7 | 15,446 | 0 | 15,446 | 13.3 | 2,948 | 3,438 | 2,088 | 1,302 | 289 | 10,065 | 8.7 |
| 3 | 2003 | 2,041.7 | 30,064 | 0 | 30,064 | 14.7 | 6,050 | 7,013 | 4,176 | 2,516 | 593 | 20,348 | 10.0 |
| 4 | 2004 | 2,047.8 | 28,989 | 0 | 28,989 | 14.2 | 6,207 | 7,153 | 4,176 | 2,428 | 609 | 20,573 | 10.0 |
| 5 | 2005 | 2,041.7 | 27,957 | 0 | 27,957 | 13.7 | 6,368 | 7,296 | 4,176 | 2,340 | 625 | 20,805 | 10.2 |
| 6 | 2006 | 2,041.7 | 26,965 | 0 | 26,965 | 13.2 | 6,534 | 7,442 | 4,176 | 2,251 | 641 | 21,044 | 10.3 |
| 7 | 2007 | 2,041.7 | 26,014 | 0 | 26,014 | 12.7 | 6,704 | 7,591 | 4,260 | 2,163 | 657 | 21,375 | 10.5 |
| 8 | 2008 | 2,047.8 | 25,097 | 0 | 25,097 | 12.3 | 6,878 | 7,742 | 4,345 | 2,075 | 675 | 21,715 | 10.6 |
| 9 | 2009 | 2,041.7 | 24,213 | 0 | 24,213 | 11.9 | 7,057 | 7,897 | 4,432 | 1,987 | 692 | 22,065 | 10.8 |
| 10 | 2010 | 2,041.7 | 23,346 | 0 | 23,346 | 11.4 | 7,240 | 8,055 | 4,521 | 1,898 | 710 | 22,425 | 11.0 |
| 11 | 2011 | 2,041.7 | 22,483 | 0 | 22,483 | 11.0 | 7,429 | 8,216 | 4,611 | 1,810 | 729 | 22,795 | 11.2 |
| 12 | 2012 | 2,047.8 | 21,620 | 0 | 21,620 | 10.6 | 7,622 | 8,381 | 4,703 | 1,722 | 747 | 23,175 | 11.3 |
| 13 | 2013 | 2,041.7 | 20,758 | 0 | 20,758 | 10.2 | 7,820 | 8,548 | 4,797 | 1,633 | 767 | 23,566 | 11.5 |
| 14 | 2014 | 2,041.7 | 19,896 | 0 | 19,896 | 9.7 | 8,023 | 8,719 | 4,893 | 1,545 | 787 | 23,968 | 11.7 |
| 15 | 2015 | 2,041.7 | 19,034 | 0 | 19,034 | 9.3 | 8,232 | 8,894 | 4,991 | 1,457 | 807 | 24,381 | 11.9 |
| 16 | 2016 | 2,047.8 | 18,174 | 0 | 18,174 | 8.9 | 8,446 | 9,072 | 5,091 | 1,369 | 828 | 24,805 | 12.1 |
| 17 | 2017 | 2,041.7 | 17,313 | 0 | 17,313 | 8.5 | 8,666 | 9,253 | 5,193 | 1,280 | 850 | 25,242 | 12.4 |
| 18 | 2018 | 2,041.7 | 16,454 | 0 | 16,454 | 8.1 | 8,891 | 9,438 | 5,297 | 1,192 | 872 | 25,690 | 12.6 |
| 19 | 2019 | 2,041.5 | 15,594 | 0 | 15,594 | 7.6 | 9,122 | 9,627 | 5,403 | 1,104 | 895 | 26,150 | 12.8 |
| 20 | 2020 | 2,047.8 | 14,736 | 0 | 14,736 | 7.2 | 9,359 | 9,819 | 5,511 | 1,015 | 918 | 26,623 | 13.0 |
| 21 | 2021 | 2,041.7 | 13,878 | 0 | 13,878 | 6.8 | 9,603 | 10,016 | 5,621 | 927 | 942 | 27,108 | 13.3 |
| 22 | 2022 | 2,041.7 | 13,113 | 0 | 13,113 | 6.4 | 9,852 | 10,216 | 5,733 | 839 | 966 | 27,607 | 13.5 |
| *2002$* | | | | | | | | | | | | | |
| Net Present Value | | | 214,636 | 0 | 214,636 | | 65,598 | 72,788 | 41,356 | 17,370 | 6,433 | 203,545 | |

| Year | | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 2 | 2002 | 25,511 | 25,511 | 22.0 | 16,031 | (9,480) | (8.2) | 24,638 | 546 | 25,184 | 21.7 | 50,695 | 43.6 |
| 3 | 2003 | 50,412 | 50,412 | 24.7 | 44,000 | (6,413) | (3.1) | 39,817 | 984 | 40,800 | 20.0 | 91,213 | 44.7 |
| 4 | 2004 | 49,562 | 49,562 | 24.2 | 46,763 | (2,799) | (1.4) | 36,365 | 1,011 | 37,376 | 18.3 | 86,938 | 42.5 |
| 5 | 2005 | 48,762 | 48,762 | 23.9 | 46,942 | (1,820) | (0.9) | 34,975 | 1,033 | 36,008 | 17.6 | 84,770 | 41.5 |
| 6 | 2006 | 48,009 | 48,009 | 23.5 | 49,712 | 1,703 | 0.8 | 37,494 | 1,059 | 38,553 | 18.9 | 86,563 | 42.4 |
| 7 | 2007 | 47,389 | 47,389 | 23.2 | 51,504 | 4,115 | 2.0 | 39,862 | 1,086 | 40,947 | 20.1 | 88,336 | 43.3 |
| 8 | 2008 | 46,813 | 46,813 | 22.9 | 53,177 | 6,364 | 3.1 | 41,953 | 1,116 | 43,069 | 21.0 | 89,882 | 43.9 |
| 9 | 2009 | 46,278 | 46,278 | 22.7 | 54,454 | 8,176 | 4.0 | 43,390 | 1,141 | 44,530 | 21.8 | 90,808 | 44.5 |
| 10 | 2010 | 45,771 | 45,771 | 22.4 | 56,851 | 11,079 | 5.4 | 44,984 | 1,169 | 46,153 | 22.6 | 91,925 | 45.0 |
| 11 | 2011 | 45,278 | 45,278 | 22.2 | 57,784 | 12,506 | 6.1 | 46,780 | 1,198 | 47,978 | 23.5 | 93,256 | 45.7 |
| 12 | 2012 | 44,795 | 44,795 | 21.9 | 64,253 | 19,458 | 9.5 | 48,830 | 1,232 | 50,062 | 24.4 | 94,857 | 46.3 |
| 13 | 2013 | 44,324 | 44,324 | 21.7 | 58,060 | 13,736 | 6.7 | 50,625 | 1,259 | 51,884 | 25.4 | 96,208 | 47.1 |
| 14 | 2014 | 43,864 | 43,864 | 21.5 | 59,562 | 15,698 | 7.7 | 52,827 | 1,291 | 54,117 | 26.5 | 97,981 | 48.0 |
| 15 | 2015 | 43,415 | 43,415 | 21.3 | 59,483 | 16,068 | 7.9 | 55,382 | 1,323 | 56,705 | 27.8 | 100,120 | 49.0 |
| 16 | 2016 | 42,979 | 42,979 | 21.0 | 59,678 | 16,699 | 8.2 | 58,049 | 1,360 | 59,409 | 29.0 | 102,388 | 50.0 |
| 17 | 2017 | 42,555 | 42,555 | 20.8 | 59,575 | 17,020 | 8.3 | 60,436 | 1,390 | 61,826 | 30.3 | 104,381 | 51.1 |
| 18 | 2018 | 42,143 | 42,143 | 20.6 | 59,857 | 17,713 | 8.7 | 62,694 | 1,425 | 64,119 | 31.4 | 106,262 | 52.0 |
| 19 | 2019 | 41,744 | 41,744 | 20.4 | 60,430 | 18,685 | 9.2 | 65,042 | 1,460 | 66,502 | 32.6 | 108,246 | 53.0 |
| 20 | 2020 | 41,358 | 41,358 | 20.2 | 68,973 | 27,615 | 13.5 | 68,004 | 1,501 | 69,506 | 33.9 | 110,864 | 54.1 |
| 21 | 2021 | 40,986 | 40,986 | 20.1 | 68,912 | 27,925 | 13.7 | 70,654 | 1,534 | 72,188 | 35.4 | 113,174 | 55.4 |
| 22 | 2022 | 40,719 | 40,719 | 19.9 | 68,995 | 28,275 | 13.8 | 73,616 | 1,572 | 75,189 | 36.8 | 115,908 | 56.8 |
| *2002$* | | | | | | | | | | | | | |
| Net Present Value | | 418,182 | 418,182 | | 483,713 | 70,623 | | 424,737 | 10,652 | 435,389 | | 853,571 | |

# CONFIDENTIAL

*DRAFT -- FOR DISCUS PURPOSES ONLY*

## Coyote Springs 2 - HALF OF PLANT TO MIRANT

### Avista Corporation

### Economic Analysis Detail

**Assumptions**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Installed Cost | 93,933 | $000s | Fixed Charge | 0.00 | per kW-month | Insurance Cost | 281.8 | 0.3% of installed cost ($000s) | Nominal Discount Rate | 7.8 | percent |
| Project Capacity | 140.0 | MW | Fixed O&M | 1.77 | 2002$ per kW-month | Gas Transport | 0.38760 | 2001 $/dth/day | Real Discount Rate | 5.0 | percent |
| Heat Rate | 7,090 | Btu/kWh | Escalation Rates | | | Electric Wheeling | 1,243 | $/MW-month thru 2006 | | | |
| Gas Usage Rate | 23.8 | 000s dth/day | Fixed O&M | 2.6 | percent | General Inflation | 2.6 | percent | | | |
| | | | Variable O&M | 2.6 | percent | | | | | | |
| | | | Transportation | 2.0 | percent | | | | | | |

**Fixed Costs**

| | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 2 | 2002 | 580.9 | 7,723 | 0 | 7,723 | 13.3 | 1,487 | 1,719 | 1,044 | 651 | 145 | 5,045 | 8.7 |
| 3 | 2003 | 1,020.9 | 15,033 | 0 | 15,033 | 14.7 | 3,051 | 3,506 | 2,088 | 1,258 | 297 | 10,200 | 10.0 |
| 4 | 2004 | 1,023.9 | 14,496 | 0 | 14,496 | 14.2 | 3,130 | 3,576 | 2,088 | 1,214 | 304 | 10,313 | 10.1 |
| 5 | 2005 | 1,020.9 | 13,980 | 0 | 13,980 | 13.7 | 3,211 | 3,648 | 2,088 | 1,170 | 312 | 10,430 | 10.2 |
| 6 | 2006 | 1,020.9 | 13,484 | 0 | 13,484 | 13.2 | 3,295 | 3,721 | 2,088 | 1,126 | 320 | 10,550 | 10.3 |
| 7 | 2007 | 1,020.9 | 13,008 | 0 | 13,008 | 12.7 | 3,380 | 3,795 | 2,130 | 1,082 | 329 | 10,716 | 10.5 |
| 8 | 2008 | 1,023.9 | 12,550 | 0 | 12,550 | 12.3 | 3,468 | 3,871 | 2,173 | 1,037 | 337 | 10,887 | 10.6 |
| 9 | 2009 | 1,020.9 | 12,108 | 0 | 12,108 | 11.9 | 3,558 | 3,949 | 2,216 | 993 | 346 | 11,062 | 10.8 |
| 10 | 2010 | 1,020.9 | 11,675 | 0 | 11,675 | 11.4 | 3,651 | 4,028 | 2,260 | 949 | 355 | 11,243 | 11.0 |
| 11 | 2011 | 1,020.9 | 11,243 | 0 | 11,243 | 11.0 | 3,746 | 4,108 | 2,306 | 905 | 364 | 11,429 | 11.2 |
| 12 | 2012 | 1,023.9 | 10,812 | 0 | 10,812 | 10.6 | 3,843 | 4,190 | 2,352 | 861 | 374 | 11,620 | 11.3 |
| 13 | 2013 | 1,020.9 | 10,380 | 0 | 10,380 | 10.2 | 3,943 | 4,274 | 2,399 | 817 | 383 | 11,816 | 11.6 |
| 14 | 2014 | 1,020.9 | 9,949 | 0 | 9,949 | 9.7 | 4,046 | 4,360 | 2,447 | 773 | 393 | 12,018 | 11.8 |
| 15 | 2015 | 1,020.9 | 9,519 | 0 | 9,519 | 9.3 | 4,151 | 4,447 | 2,496 | 728 | 404 | 12,225 | 12.0 |
| 16 | 2016 | 1,023.9 | 9,088 | 0 | 9,088 | 8.9 | 4,259 | 4,536 | 2,546 | 684 | 414 | 12,439 | 12.1 |
| 17 | 2017 | 1,020.9 | 8,658 | 0 | 8,658 | 8.5 | 4,370 | 4,626 | 2,596 | 640 | 425 | 12,657 | 12.4 |
| 18 | 2018 | 1,020.9 | 8,229 | 0 | 8,229 | 8.1 | 4,483 | 4,719 | 2,648 | 596 | 436 | 12,882 | 12.6 |
| 19 | 2019 | 1,020.7 | 7,799 | 0 | 7,799 | 7.6 | 4,600 | 4,813 | 2,701 | 552 | 447 | 13,114 | 12.8 |
| 20 | 2020 | 1,023.9 | 7,370 | 0 | 7,370 | 7.2 | 4,719 | 4,910 | 2,755 | 508 | 459 | 13,351 | 13.0 |
| 21 | 2021 | 1,020.9 | 6,941 | 0 | 6,941 | 6.8 | 4,842 | 5,008 | 2,810 | 464 | 471 | 13,595 | 13.3 |
| 22 | 2022 | 1,020.9 | 6,558 | 0 | 6,558 | 6.4 | 4,968 | 5,108 | 2,867 | 419 | 483 | 13,845 | 13.6 |
| *2002$* | | | | | | | | | | | | | |
| Net Present Value | | | 107,332 | 0 | 107,332 | | 33,077 | 36,394 | 20,678 | 8,685 | 3,217 | 102,051 | |

| | Year | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 2 | 2002 | 12,769 | 12,769 | 22.0 | 8,016 | (4,753) | (8.2) | 12,319 | 273 | 12,592 | 21.7 | 25,361 | 43.7 |
| 3 | 2003 | 25,233 | 25,233 | 24.7 | 22,000 | (3,233) | (3.2) | 19,908 | 492 | 20,400 | 20.0 | 45,633 | 44.7 |
| 4 | 2004 | 24,808 | 24,808 | 24.2 | 23,381 | (1,427) | (1.4) | 18,182 | 506 | 18,688 | 18.3 | 43,497 | 42.5 |
| 5 | 2005 | 24,409 | 24,409 | 23.9 | 23,471 | (938) | (0.9) | 17,487 | 517 | 18,004 | 17.6 | 42,413 | 41.5 |
| 6 | 2006 | 24,034 | 24,034 | 23.5 | 24,856 | 822 | 0.8 | 18,747 | 530 | 19,277 | 18.9 | 43,310 | 42.4 |
| 7 | 2007 | 23,724 | 23,724 | 23.2 | 25,752 | 2,028 | 2.0 | 19,931 | 543 | 20,474 | 20.1 | 44,198 | 43.3 |
| 8 | 2008 | 23,437 | 23,437 | 22.9 | 26,588 | 3,152 | 3.1 | 20,977 | 558 | 21,535 | 21.0 | 44,972 | 43.9 |
| 9 | 2009 | 23,170 | 23,170 | 22.7 | 27,227 | 4,057 | 4.0 | 21,695 | 570 | 22,265 | 21.8 | 45,436 | 44.5 |
| 10 | 2010 | 22,918 | 22,918 | 22.4 | 28,425 | 5,508 | 5.4 | 22,492 | 585 | 23,077 | 22.6 | 45,994 | 45.1 |
| 11 | 2011 | 22,672 | 22,672 | 22.2 | 28,892 | 6,220 | 6.1 | 23,390 | 599 | 23,989 | 23.5 | 46,661 | 45.7 |
| 12 | 2012 | 22,431 | 22,431 | 21.9 | 32,126 | 9,695 | 9.5 | 24,415 | 616 | 25,031 | 24.4 | 47,463 | 46.4 |
| 13 | 2013 | 22,197 | 22,197 | 21.7 | 29,030 | 6,833 | 6.7 | 25,312 | 630 | 25,942 | 25.4 | 48,139 | 47.2 |
| 14 | 2014 | 21,967 | 21,967 | 21.5 | 29,781 | 7,813 | 7.7 | 26,413 | 645 | 27,059 | 26.5 | 49,026 | 48.0 |
| 15 | 2015 | 21,744 | 21,744 | 21.3 | 29,742 | 7,997 | 7.8 | 27,691 | 661 | 28,352 | 27.8 | 50,097 | 49.1 |
| 16 | 2016 | 21,527 | 21,527 | 21.0 | 29,839 | 8,312 | 8.1 | 29,025 | 680 | 29,705 | 29.0 | 51,232 | 50.0 |
| 17 | 2017 | 21,316 | 21,316 | 20.9 | 29,787 | 8,471 | 8.3 | 30,218 | 695 | 30,913 | 30.3 | 52,229 | 51.2 |
| 18 | 2018 | 21,111 | 21,111 | 20.7 | 29,928 | 8,817 | 8.6 | 31,347 | 712 | 32,059 | 31.4 | 53,171 | 52.1 |
| 19 | 2019 | 20,913 | 20,913 | 20.5 | 30,215 | 9,302 | 9.1 | 32,521 | 730 | 33,251 | 32.6 | 54,164 | 53.1 |
| 20 | 2020 | 20,721 | 20,721 | 20.2 | 34,487 | 13,766 | 13.4 | 34,002 | 751 | 34,753 | 33.9 | 55,474 | 54.2 |
| 21 | 2021 | 20,536 | 20,536 | 20.1 | 34,456 | 13,920 | 13.6 | 35,327 | 767 | 36,094 | 35.4 | 56,630 | 55.5 |
| 22 | 2022 | 20,403 | 20,403 | 20.0 | 34,497 | 14,094 | 13.8 | 36,808 | 786 | 37,594 | 36.8 | 57,998 | 56.8 |
| *2002$* | | | | | | | | | | | | | |
| Net Present Value | | 209,382 | 209,382 | | 241,857 | 34,997 | | 212,368 | 5,326 | 217,695 | | 427,077 | |

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# Coyote Springs 2 — OCTOBER 8, 2001 ENRON TOLL OFFER

## Enron Toll Offer

## Economic Analysis Detail

**Assumptions**

| | | | | | | |
|---|---|---|---|---|---|---|
| Installed Cost | 0 | $000s | Fixed Charge | 8.15 | per kW-month (no escalation) | |
| Project Capacity | 280.0 | MW | Fixed O&M | 0.25 | 2002$ per kW-month (difference between $1.75 and Enron's assumed $1.50) | |
| Heat Rate | 7,345 | Btu/kWh | Escalation Rates | | Insurance Cost | 0.0 0.3% of installed cost ($000s) |
| Gas Usage Rate | 49.4 | 000s dth/day | Fixed O&M | 2.6 percent | Gas Transport | 0.38760 2001 $/dth/day |
| | | | Variable O&M | 2.6 percent | Electric Wheeling | 1,243 $/MW-month thru 2006 |
| | | | Transportation | 2.0 percent | General Inflation | 2.6 percent |

Nominal Discount Rate 7.8 percent
Real Discount Rate 5.0 percent

| Row | | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 19 | 2 | 2002 | 1,073.7 | 946 | 0 | 946 | 0.9 | 14,112 | 3,561 | 2,088 | 0 | 0 | 19,762 | 18.4 |
| 20 | 3 | 2003 | 2,004.6 | 1,901 | 0 | 1,901 | 0.9 | 28,246 | 7,265 | 4,176 | 0 | 0 | 39,687 | 19.8 |
| 21 | 4 | 2004 | 2,047.8 | 1,909 | 0 | 1,909 | 0.9 | 28,268 | 7,410 | 4,176 | 0 | 0 | 39,855 | 19.5 |
| 22 | 5 | 2005 | 2,041.7 | 1,917 | 0 | 1,917 | 0.9 | 28,291 | 7,559 | 4,176 | 0 | 0 | 40,026 | 19.6 |
| 23 | 6 | 2006 | 2,041.7 | 1,925 | 0 | 1,925 | 0.9 | 28,315 | 7,710 | 4,176 | 0 | 0 | 40,201 | 19.7 |
| 24 | 7 | 2007 | 2,041.7 | 1,938 | 0 | 1,938 | 0.9 | 28,339 | 7,864 | 4,260 | 0 | 0 | 40,463 | 19.8 |
| 25 | 8 | 2008 | 2,047.8 | 1,951 | 0 | 1,951 | 1.0 | 28,364 | 8,021 | 4,345 | 0 | 0 | 40,730 | 19.9 |
| 26 | 9 | 2009 | 2,041.7 | 1,964 | 0 | 1,964 | 1.0 | 28,389 | 8,182 | 4,432 | 0 | 0 | 41,003 | 20.1 |
| 27 | 10 | 2010 | 2,041.7 | 1,977 | 0 | 1,977 | 1.0 | 28,415 | 8,345 | 4,521 | 0 | 0 | 41,281 | 20.2 |
| 28 | 11 | 2011 | 2,041.7 | 1,991 | 0 | 1,991 | 1.0 | 28,442 | 8,512 | 4,611 | 0 | 0 | 41,566 | 20.4 |
| 29 | 12 | 2012 | 2,047.8 | 2,005 | 0 | 2,005 | 1.0 | 28,470 | 8,682 | 4,703 | 0 | 0 | 41,856 | 20.4 |
| 30 | 13 | 2013 | 2,041.7 | 2,019 | 0 | 2,019 | 1.0 | 28,498 | 8,856 | 4,797 | 0 | 0 | 42,152 | 20.6 |
| 31 | 14 | 2014 | 2,041.7 | 2,033 | 0 | 2,033 | 1.0 | 28,527 | 9,033 | 4,893 | 0 | 0 | 42,454 | 20.8 |
| 32 | 15 | 2015 | 2,041.7 | 2,048 | 0 | 2,048 | 1.0 | 28,557 | 9,214 | 4,991 | 0 | 0 | 42,762 | 20.9 |
| 33 | 16 | 2016 | 2,047.8 | 2,063 | 0 | 2,063 | 1.0 | 28,587 | 9,398 | 5,091 | 0 | 0 | 43,076 | 21.0 |
| 34 | 17 | 2017 | 2,041.7 | 2,078 | 0 | 2,078 | 1.0 | 28,618 | 9,586 | 5,193 | 0 | 0 | 43,398 | 21.3 |
| 35 | 18 | 2018 | 2,041.7 | 2,094 | 0 | 2,094 | 1.0 | 28,651 | 9,778 | 5,297 | 0 | 0 | 43,725 | 21.4 |
| 36 | 19 | 2019 | 2,041.5 | 2,110 | 0 | 2,110 | 1.0 | 28,684 | 9,973 | 5,403 | 0 | 0 | 44,060 | 21.6 |
| 37 | 20 | 2020 | 2,047.8 | 2,126 | 0 | 2,126 | 1.0 | 28,717 | 10,173 | 5,511 | 0 | 0 | 44,401 | 21.7 |
| 38 | 21 | 2021 | 2,041.7 | 2,143 | 0 | 2,143 | 1.0 | 28,752 | 10,376 | 5,621 | 0 | 0 | 44,749 | 21.9 |
| 39 | 22 | 2022 | 2,041.7 | 2,160 | 0 | 2,160 | 1.1 | 28,788 | 10,584 | 5,733 | 0 | 0 | 45,105 | 22.1 |
| 40 | | | | | | | | | | | | | | |
| 41 | 2002$ | | | | | | | | | | | | | |
| 42 | Net Present Value | | | 17,883 | 0 | 17,883 | | 256,639 | 75,409 | 41,356 | 0 | 0 | 373,404 | |

| Row | Year | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 19 | 2002 | 20,708 | 20,708 | 19.3 | 12,439 | (8,269) | (7.7) | 23,593 | 2,695 | 26,288 | 24.5 | 46,996 | 43.8 |
| 20 | 2003 | 41,588 | 41,588 | 20.7 | 37,775 | (3,813) | (1.9) | 41,076 | 5,157 | 46,234 | 23.1 | 87,822 | 43.8 |
| 21 | 2004 | 41,764 | 41,764 | 20.4 | 40,554 | (1,210) | (0.6) | 38,185 | 5,400 | 43,585 | 21.3 | 85,349 | 41.7 |
| 22 | 2005 | 41,943 | 41,943 | 20.5 | 40,706 | (1,237) | (0.6) | 36,725 | 5,519 | 42,244 | 20.7 | 84,187 | 41.2 |
| 23 | 2006 | 42,126 | 42,126 | 20.6 | 43,238 | 1,112 | 0.5 | 39,371 | 5,657 | 45,028 | 22.1 | 87,154 | 42.7 |
| 24 | 2007 | 42,401 | 42,401 | 20.8 | 44,796 | 2,395 | 1.2 | 41,857 | 5,798 | 47,655 | 23.3 | 90,056 | 44.1 |
| 25 | 2008 | 42,681 | 42,681 | 20.8 | 46,232 | 3,551 | 1.7 | 44,053 | 5,961 | 50,014 | 24.4 | 92,695 | 45.3 |
| 26 | 2009 | 42,967 | 42,967 | 21.0 | 47,331 | 4,364 | 2.1 | 45,561 | 6,092 | 51,653 | 25.3 | 94,620 | 46.3 |
| 27 | 2010 | 43,259 | 43,259 | 21.2 | 49,524 | 6,266 | 3.1 | 47,236 | 6,244 | 53,480 | 26.2 | 96,738 | 47.4 |
| 28 | 2011 | 43,556 | 43,556 | 21.3 | 50,241 | 6,685 | 3.3 | 49,121 | 6,400 | 55,521 | 27.2 | 99,078 | 48.5 |
| 29 | 2012 | 43,860 | 43,860 | 21.4 | 56,461 | 12,601 | 6.2 | 51,274 | 6,580 | 57,854 | 28.3 | 101,714 | 49.7 |
| 30 | 2013 | 44,170 | 44,170 | 21.6 | 50,061 | 5,891 | 2.9 | 53,159 | 6,724 | 59,883 | 29.3 | 104,053 | 51.0 |
| 31 | 2014 | 44,487 | 44,487 | 21.8 | 51,316 | 6,829 | 3.3 | 55,471 | 6,892 | 62,363 | 30.5 | 106,850 | 52.3 |
| 32 | 2015 | 44,810 | 44,810 | 21.9 | 50,970 | 6,160 | 3.0 | 58,154 | 7,065 | 65,218 | 31.9 | 110,028 | 53.9 |
| 33 | 2016 | 45,140 | 45,140 | 22.0 | 50,870 | 5,730 | 2.8 | 60,954 | 7,263 | 68,217 | 33.3 | 113,357 | 55.4 |
| 34 | 2017 | 45,476 | 45,476 | 22.3 | 50,517 | 5,041 | 2.5 | 63,461 | 7,422 | 70,884 | 34.7 | 116,359 | 57.0 |
| 35 | 2018 | 45,819 | 45,819 | 22.4 | 50,535 | 4,716 | 2.3 | 65,832 | 7,608 | 73,440 | 36.0 | 119,259 | 58.4 |
| 36 | 2019 | 46,170 | 46,170 | 22.6 | 50,837 | 4,667 | 2.3 | 68,297 | 7,797 | 76,095 | 37.3 | 122,264 | 59.9 |
| 37 | 2020 | 46,527 | 46,527 | 22.7 | 59,054 | 12,527 | 6.1 | 71,408 | 8,017 | 79,425 | 38.8 | 125,952 | 61.5 |
| 38 | 2021 | 46,892 | 46,892 | 23.0 | 58,717 | 11,824 | 5.8 | 74,190 | 8,193 | 82,383 | 40.3 | 129,275 | 63.3 |
| 39 | 2022 | 47,265 | 47,265 | 23.1 | 58,485 | 11,220 | 5.5 | 77,301 | 8,398 | 85,699 | 42.0 | 132,964 | 65.1 |
| 40 | | | | | | | | | | | | | |
| 41 | 2002$ | | | | | | | | | | | | |
| 42 | Net Present Value | 391,287 | 391,287 | | 416,259 | 26,912 | | 443,448 | 56,620 | 500,068 | | 891,355 | |

**CONFIDENTIAL**

# Coyote Springs 2 - PG&E TOLL OFFER

## Avista Corporation

### Economic Analysis Detail - PG&E NEG Purchase/Toll-Back

**Assumptions**

| | | | |
|---|---|---|---|
| Installed Cost | 0 | $000s | |
| Project Capacity | 280.0 | MW | |
| Heat Rate | 7,090 | Btu/kWh | |
| Gas Usage Rate | 47.6 | 000s dth/day | |
| Fixed Charge | 9.75 | per kW-month | |
| Fixed O&M | 1.75 | 2002$ per kW-month | |
| Escalation Rates | | | |
| Fixed O&M | 2.1 | percent | |
| Variable O&M | 2.6 | percent | |
| Transportation | 2.0 | percent | |
| Insurance Cost | 0.0 | 0.3% of installed cost ($000s) | |
| Gas Transport | 0.38760 | 2001 $/dth/day | |
| Electric Wheeling | 1,243 | $/MW-month thru 2006 | |
| General Inflation | 2.6 | percent | |
| Nominal Discount Rate | 7.8 | percent | |
| Real Discount Rate | 5.0 | percent | |

**Fixed Costs**

| Row | | Year | Energy (GWh) | Capital Recovery and Miscellaneous: Project ($000s) | Fixed Chrg. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) | Operations & Maintenance: Fixed ($000s) | Gtrans ($000s) | Etrans ($000s) | PrTax ($000s) | Insur. ($000s) | Total Costs ($000s) | Total Costs ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 1 | 2001 | 0.0 | 0 | 0 | 0 | #DIV/0! | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! |
| 19 | 2 | 2002 | 1,161.7 | 1,267 | 0 | 1,267 | 1.1 | 19,328 | 3,438 | 2,088 | 1,302 | 289 | 26,445 | 22.8 |
| 20 | 3 | 2003 | 2,041.7 | 2,575 | 0 | 2,575 | 1.3 | 39,465 | 7,013 | 4,176 | 2,516 | 593 | 53,764 | 26.3 |
| 21 | 4 | 2004 | 2,047.8 | 2,618 | 0 | 2,618 | 1.3 | 40,290 | 7,153 | 4,176 | 2,428 | 609 | 54,656 | 26.7 |
| 22 | 5 | 2005 | 2,041.7 | 2,661 | 0 | 2,661 | 1.3 | 41,133 | 7,296 | 4,176 | 2,340 | 625 | 55,570 | 27.2 |
| 23 | 6 | 2006 | 2,041.7 | 2,706 | 0 | 2,706 | 1.3 | 41,993 | 7,442 | 4,176 | 2,251 | 641 | 56,504 | 27.7 |
| 24 | 7 | 2007 | 2,041.7 | 2,756 | 0 | 2,756 | 1.3 | 42,872 | 7,591 | 4,260 | 2,163 | 657 | 57,543 | 28.2 |
| 25 | 8 | 2008 | 2,047.8 | 2,807 | 0 | 2,807 | 1.4 | 43,768 | 7,742 | 4,345 | 2,075 | 675 | 58,605 | 28.6 |
| 26 | 9 | 2009 | 2,041.7 | 2,859 | 0 | 2,859 | 1.4 | 44,684 | 7,897 | 4,432 | 1,987 | 692 | 59,692 | 29.2 |
| 27 | 10 | 2010 | 2,041.7 | 2,912 | 0 | 2,912 | 1.4 | 45,618 | 8,055 | 4,521 | 1,898 | 710 | 60,803 | 29.8 |
| 28 | 11 | 2011 | 2,041.7 | 2,966 | 0 | 2,966 | 1.5 | 46,572 | 8,216 | 4,611 | 1,810 | 729 | 61,938 | 30.3 |
| 29 | 12 | 2012 | 2,047.8 | 3,022 | 0 | 3,022 | 1.5 | 47,546 | 8,381 | 4,703 | 1,722 | 747 | 63,100 | 30.8 |
| 30 | 13 | 2013 | 2,041.7 | 3,079 | 0 | 3,079 | 1.5 | 48,541 | 8,548 | 4,797 | 1,633 | 767 | 64,287 | 31.5 |
| 31 | 14 | 2014 | 2,041.7 | 3,137 | 0 | 3,137 | 1.5 | 49,556 | 8,719 | 4,893 | 1,545 | 787 | 65,501 | 32.1 |
| 32 | 15 | 2015 | 2,041.7 | 3,196 | 0 | 3,196 | 1.6 | 50,593 | 8,894 | 4,991 | 1,457 | 807 | 66,742 | 32.7 |
| 33 | 16 | 2016 | 2,047.8 | 3,257 | 0 | 3,257 | 1.6 | 51,651 | 9,072 | 5,091 | 1,369 | 828 | 68,010 | 33.2 |
| 34 | 17 | 2017 | 2,041.7 | 3,319 | 0 | 3,319 | 1.6 | 52,731 | 9,253 | 5,193 | 1,280 | 850 | 69,307 | 33.9 |
| 35 | 18 | 2018 | 2,041.7 | 3,383 | 0 | 3,383 | 1.7 | 53,834 | 9,438 | 5,297 | 1,192 | 872 | 70,633 | 34.6 |
| 36 | 19 | 2019 | 2,041.5 | 3,448 | 0 | 3,448 | 1.7 | 54,960 | 9,627 | 5,403 | 1,104 | 895 | 71,988 | 35.3 |
| 37 | 20 | 2020 | 2,047.8 | 3,514 | 0 | 3,514 | 1.7 | 56,109 | 9,819 | 5,511 | 1,015 | 918 | 73,373 | 35.8 |
| 38 | 21 | 2021 | 2,041.7 | 3,582 | 0 | 3,582 | 1.8 | 57,283 | 10,016 | 5,621 | 927 | 942 | 74,788 | 36.6 |
| 39 | 22 | 2022 | 2,041.7 | 3,651 | 0 | 3,651 | 1.8 | 58,481 | 10,216 | 5,733 | 839 | 966 | 76,235 | 37.3 |
| 41 | 2002$ | | | | | | | | | | | | | |
| 42 | Net Present Value | | | 26,355 | 0 | 26,355 | | 412,346 | 72,788 | 41,356 | 17,370 | 6,433 | 550,294 | |

| Row | Year | Total Fixed Costs: Before 10% Credit ($000s) | After 10% Credit ($000s) | After 10% Credit ($/MWh) | Less Operating Margin ($000s) | Net Project Benefit ($000s) | Net Project Benefit ($/MWh) | Variable Costs: Gas ($000s) | O&M ($000s) | Total Variable ($000s) | Total Variable ($/MWh) | Total Project Cost after Credits ($000s) | Total Project Cost after Credits ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 2001 | 0 | 0 | #DIV/0! | 0 | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! | 0 | #DIV/0! |
| 19 | 2002 | 27,712 | 27,712 | 23.9 | 16,031 | (11,681) | (10.1) | 24,638 | 546 | 25,184 | 21.7 | 52,896 | 45.5 |
| 20 | 2003 | 56,338 | 56,338 | 27.6 | 43,999 | (12,340) | (6.0) | 39,817 | 984 | 40,801 | 20.0 | 97,139 | 47.6 |
| 21 | 2004 | 57,274 | 57,274 | 28.0 | 46,762 | (10,512) | (5.1) | 36,366 | 1,011 | 37,377 | 18.3 | 94,651 | 46.2 |
| 22 | 2005 | 58,231 | 58,231 | 28.5 | 46,941 | (11,290) | (5.5) | 34,975 | 1,033 | 36,009 | 17.6 | 94,240 | 46.2 |
| 23 | 2006 | 59,210 | 59,210 | 29.0 | 49,712 | (9,498) | (4.7) | 37,495 | 1,059 | 38,554 | 18.9 | 97,764 | 47.9 |
| 24 | 2007 | 60,299 | 60,299 | 29.5 | 51,503 | (8,796) | (4.3) | 39,862 | 1,086 | 40,948 | 20.1 | 101,247 | 49.6 |
| 25 | 2008 | 61,412 | 61,412 | 30.0 | 53,176 | (8,236) | (4.0) | 41,954 | 1,116 | 43,070 | 21.0 | 104,482 | 51.0 |
| 26 | 2009 | 62,551 | 62,551 | 30.6 | 54,453 | (8,098) | (4.0) | 43,390 | 1,141 | 44,531 | 21.8 | 107,082 | 52.4 |
| 27 | 2010 | 63,715 | 63,715 | 31.2 | 56,850 | (6,865) | (3.4) | 44,985 | 1,169 | 46,154 | 22.6 | 109,869 | 53.8 |
| 28 | 2011 | 64,905 | 64,905 | 31.8 | 57,783 | (7,122) | (3.5) | 46,781 | 1,198 | 47,979 | 23.5 | 112,884 | 55.3 |
| 29 | 2012 | 66,122 | 66,122 | 32.3 | 64,252 | (1,870) | (0.9) | 48,831 | 1,232 | 50,063 | 24.4 | 116,185 | 56.7 |
| 30 | 2013 | 67,366 | 67,366 | 33.0 | 58,059 | (9,307) | (4.6) | 50,626 | 1,259 | 51,885 | 25.4 | 119,251 | 58.4 |
| 31 | 2014 | 68,638 | 68,638 | 33.6 | 59,561 | (9,077) | (4.4) | 52,827 | 1,291 | 54,118 | 26.5 | 122,756 | 60.1 |
| 32 | 2015 | 69,938 | 69,938 | 34.3 | 59,482 | (10,456) | (5.1) | 55,383 | 1,323 | 56,706 | 27.8 | 126,644 | 62.0 |
| 33 | 2016 | 71,267 | 71,267 | 34.8 | 59,677 | (11,590) | (5.7) | 58,050 | 1,360 | 59,410 | 29.0 | 130,677 | 63.8 |
| 34 | 2017 | 72,626 | 72,626 | 35.6 | 59,574 | (13,053) | (6.4) | 60,437 | 1,390 | 61,827 | 30.3 | 134,453 | 65.9 |
| 35 | 2018 | 74,015 | 74,015 | 36.3 | 59,856 | (14,160) | (6.9) | 62,695 | 1,425 | 64,120 | 31.4 | 138,135 | 67.7 |
| 36 | 2019 | 75,435 | 75,435 | 37.0 | 60,429 | (15,007) | (7.4) | 65,043 | 1,460 | 66,503 | 32.6 | 141,938 | 69.5 |
| 37 | 2020 | 76,887 | 76,887 | 37.5 | 68,972 | (7,914) | (3.9) | 68,005 | 1,501 | 69,506 | 33.9 | 146,393 | 71.5 |
| 38 | 2021 | 78,370 | 78,370 | 38.4 | 68,911 | (9,460) | (4.6) | 70,655 | 1,534 | 72,189 | 35.4 | 150,559 | 73.7 |
| 39 | 2022 | 79,887 | 79,887 | 39.1 | 68,994 | (10,893) | (5.3) | 73,618 | 1,572 | 75,190 | 36.8 | 155,076 | 76.0 |
| 42 | Net Present Value | 576,649 | 576,649 | | 483,707 | (100,163) | | 424,743 | 10,652 | 435,395 | | 1,012,044 | |

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01________

EXHIBIT NO. __ (RJL-25)

## Coyote Springs II - O&M Costs

| | Total | Nov-02 | Dec-02 | Jan-03 | Feb-03 | Mar-03 | Apr-03 | May-03 | Jun-03 | Jul-03 | Aug-03 | Sep-03 | Oct-03 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Shared Fixed Costs | $815,509 | $66,517.86 | $66,517.86 | $68,247.32 | $68,247.32 | $68,247.32 | $68,247.32 | $68,247.32 | $68,247.32 | $68,247.32 | $68,247.32 | $68,247.32 | $68,247.32 |
| Unit Specific Fixed Costs | $139,589 | $11,385.71 | $11,385.71 | $11,681.74 | $11,681.74 | $11,681.74 | $11,681.74 | $11,681.74 | $11,681.74 | $11,681.74 | $11,681.74 | $11,681.74 | $11,681.74 |
| Port of Morrow Fees | $299,500 | $24,958.33 | $24,958.33 | $24,958.33 | $24,958.33 | $24,958.33 | $24,958.33 | $24,958.33 | $24,958.33 | $24,958.33 | $24,958.33 | $24,958.33 | $24,958.33 |
| Major Maint. - Fixed Costs | $375,000 | $31,250.00 | $31,250.00 | $31,250.00 | $31,250.00 | $31,250.00 | $31,250.00 | $31,250.00 | $31,250.00 | $31,250.00 | $31,250.00 | $31,250.00 | $31,250.00 |
| Sub-Total - Fixed Costs | $1,629,598 | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| Shared Variable Costs | $60,590 | $4,942.09 | $4,942.09 | $5,070.58 | $5,070.58 | $5,070.58 | $5,070.58 | $5,070.58 | $5,070.58 | $5,070.58 | $5,070.58 | $5,070.58 | $5,070.58 |
| Unit Specific Variable Costs | $110,136 | $8,983.40 | $8,983.40 | $9,216.97 | $9,216.97 | $9,216.97 | $9,216.97 | $9,216.97 | $9,216.97 | $9,216.97 | $9,216.97 | $9,216.97 | $9,216.97 |
| Major Maint. - Variable Costs | $1,027,808 | $85,650.69 | $85,650.69 | $85,650.69 | $85,650.69 | $85,650.69 | $85,650.69 | $85,650.69 | $85,650.69 | $85,650.69 | $85,650.69 | $85,650.69 | $85,650.69 |
| Sub-Total Variable Costs | $1,198,535 | $1.56 /MWh | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| Total | $2,828,133 | | | | | | | | | | | | |

Note: 1) Based on 5971 hours of operation. (776,131MWh/128.3MW=5971hrs)
2) 2003 PGE Operations Costs escallated at 2.6 %
3) Nov 2002 through Oct 2003 period

11-27-2001

## Boulder Park

| Item | Total | Nov-02 | Dec-02 | Jan-03 | Feb-03 | Mar-03 | Apr-03 | May-03 | Jun-03 | Jul-03 | Aug-03 | Sep-03 | Oct-03 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manpower | | | | | | | | | | | | | |
| Journeyman Plant Specialist | $ 79,249.01 | $ 6,464.03 | $ 6,464.03 | $ 6,632.09 | $ 6,632.09 | $ 6,632.09 | $ 6,632.09 | $ 6,632.09 | $ 6,632.09 | $ 6,632.09 | $ 6,632.09 | $ 6,632.09 | $ 6,632.09 |
| Journeyman Plant Specialist OT | $ 13,089.38 | $ 1,526.31 | $ 1,526.31 | $ 1,662.21 | $ 810.84 | $ 1,621.66 | $ 810.84 | $ 1,216.25 | $ 782.99 | $ 782.99 | $ 782.99 | $ 782.99 | $ 782.99 |
| Wartsila Contract? | $ - | | | | | | | | | | | | |
| Transportation | | | | | | | | | | | | | |
| Pick-Up Truck | $ 11,034.00 | $ 900.00 | $ 900.00 | $ 923.40 | $ 923.40 | $ 923.40 | $ 923.40 | $ 923.40 | $ 923.40 | $ 923.40 | $ 923.40 | $ 923.40 | $ 923.40 |
| Gas | $ 1,226.00 | $ 100.00 | $ 100.00 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 |
| Training | | | | | | | | | | | | | |
| Class/User Group | $ 8,208.00 | | | | | $ 4,104.00 | | | $ 4,104.00 | | | | |
| Operating | | | | | | | | | | | | | |
| Lube Oil | $ 18,981.00 | | | $ 3,591.00 | | | | | | | $ 5,130.00 | $ 5,130.00 | $ 5,130.00 |
| Miscellaneous | $ 9,808.00 | $ 800.00 | $ 800.00 | $ 820.80 | $ 820.80 | $ 820.80 | $ 820.80 | $ 820.80 | $ 820.80 | $ 820.80 | $ 820.80 | $ 820.80 | $ 820.80 |
| Light Bulbs | | | | | | | | | | | | | |
| Toilet Paper | | | | | | | | | | | | | |
| Rags/Linens | | | | | | | | | | | | | |
| Phone | | | | | | | | | | | | | |
| Office Supplies | | | | | | | | | | | | | |
| Computer Refresh | | | | | | | | | | | | | |
| Sewer | | | | | | | | | | | | | |
| Garbage/Waste | | | | | | | | | | | | | |
| Etc | | | | | | | | | | | | | |
| Anti-Freeze | $ 5,504.49 | | | $ 1,041.39 | | | | | | | $ 1,487.70 | $ 1,487.70 | $ 1,487.70 |
| Hazardous Waste Disposal | $ 12,260.00 | $ 1,000.00 | $ 1,000.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 |
| Lube Oil | | | | | | | | | | | | | |
| Anti-Freeze | | | | | | | | | | | | | |
| Etc | | | | | | | | | | | | | |
| Urea | $ 22,777.20 | | | $ 4,309.20 | | | | | | | $ 6,156.00 | $ 6,156.00 | $ 6,156.00 |
| Spark Plugs | $ 9,110.88 | | | $ 1,723.68 | | | | | | | $ 2,462.40 | $ 2,462.40 | $ 2,462.40 |
| Spark Plug Wires | $ 3,796.20 | | | $ 718.20 | | | | | | | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 |
| Spare Parts | $ 12,260.00 | $ 1,000.00 | $ 1,000.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 |
| Domestic Water | $ 1,226.00 | $ 100.00 | $ 100.00 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 | $ 102.60 |
| Weed Control | $ 4,104.00 | | | | | | $ 2,052.00 | | | $ 2,052.00 | | | |
| Landscaping | $ 5,130.00 | | | | | | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | | |
| Sprinkler System | $ 5,130.00 | | | | | | $ 5,130.00 | | | | | | |
| Communications (T1 line) | $ 7,969.00 | $ 650.00 | $ 650.00 | $ 666.90 | $ 666.90 | $ 666.90 | $ 666.90 | $ 666.90 | $ 666.90 | $ 666.90 | $ 666.90 | $ 666.90 | $ 666.90 |
| Tools | $ 12,260.00 | $ 1,000.00 | $ 1,000.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 |
| Misc. Parts, etc. | $ 12,260.00 | $ 1,000.00 | $ 1,000.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 | $ 1,026.00 |
| Computer | | | | | | | | | | | | | |
| Maintenance | | | | | | | | | | | | | |
| Misc. Maintenance - Fixed | $ 101,300.00 | | $ 25,000.00 | | | $ 25,000.00 | | | $ 25,650.00 | | | $ 25,650.00 | |
| Environmental | | | | | | | | | | | | | |
| Urea/Ammonia (See above) | | | | | | | | | | | | | |
| Total | $ 356,683.16 | | | | | | | | | | | | |

Note: 1) Based on 2700 hours of operation.
2) 2003 Costs escallated at 2.6%

11-27-2001