BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-05_____

DIRECT TESTIMONY OF

CLINT KALICH

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Clint Kalich. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. In what capacity are you employed?

A. I am the Manager of Resource Planning & Power Supply Analyses, in the Energy Resources Department of Avista Utilities.

Q. Please state your educational background and professional experience.

A. I am a 1991 graduate of Central Washington University with a Bachelor of Science Degree in Business Economics. Shortly after graduation, I accepted an analyst position with Economic and Engineering Services, Inc. (now EES Consulting, Inc.), a Northwest management-consulting firm located in Bellevue, Washington. While employed by EES, I worked primarily for municipalities, public utility districts, and cooperatives in the area of electric utility management. My specific areas of focus were economic analyses around new resource development, rate case proceedings involving the Bonneville Power Administration, integrated (least-cost) resource planning, and demand-side management program development. In late 1995, I left Economic and Engineering Services, Inc. to join Tacoma Power in Tacoma, Washington. I provided key analytical and policy support in the areas of resource development, procurement, and optimization, hydroelectric operations and re-licensing, unbundled power supply rate-making, contract negotiations, and system operations. I helped develop, and ultimately managed, Tacoma Power's industrial market access program serving one-quarter of the company's retail load. In mid-2000 I joined Avista Utilities as a Senior Power Resource Analyst. In 2001, I was promoted to my current position. I assist the Company in the areas of resource analysis, dispatch modeling, resource procurement, integrated resource planning, and rate case proceedings. Much of my career has involved resource dispatch modeling of the nature described in this testimony.

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

A. I will address the appropriate stream flow record to be used to normalize hydroelectric generation for ratemaking purposes. My testimony will also describe the Company's use of the AURORA dispatch model, hereinafter referred to as the "Dispatch Model." I will discuss key inputs, assumptions, and results. Below is a table of contents for my testimony:

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring two exhibits marked Exhibit No. ___(CGK-2) and Exhibit No. ___ (CGK-3). All information contained in the exhibits was prepared under my direction.

II. EXECUTIVE SUMMARY

Q. Please provide an overview of your direct testimony.

A. My testimony will demonstrate that the 60-year stream flow record should be used for ratemaking. Previous proforma power supply expense levels were based on a 40-year rolling average methodology developed during a case approximately 20 years ago. In the recent Puget Sound Energy ("PSE") case (Docket Nos. UG-040640 and UE-040641), the WUTC, in Order No. 06 dated February 18, 2005, approved the use of the 50-year stream flow data (1928-1978). I will show that the use of the entire 60-year record is superior to both the 40-year rolling average and the 50-year average.

I will also explain the key assumptions driving the Dispatch Model's market forecast of electricity prices. The discussion includes the variables of natural gas, Western Electricity Coordination Council ("WECC") loads and resources, and hydroelectric conditions. I will explain how the Company's generation resources and various contracts were modeled. I will describe how the model dispatches our resources and contracts in a manner that maximizes benefits to customers. Finally, I will explain the modeling results that are provided to Witness Johnson to complete his power supply proforma adjustment calculations.

III. 60-YEAR HYDROELECTRIC RECORD

Q. Please provide background to the hydroelectric normalization issue?

A. Avista's power supply costs for ratemaking purposes are established based on hydroelectric generation under "normal" precipitation and stream flow conditions. The estimate of normal traditionally has been developed using a set or subset of the historical stream flow data record run through the Northwest Power Pool's ("NWPP's") HyReg model.[1] In a mid-1980's Commission order, the WUTC ruled that the record used for hydro normalization would be a 40-year rolling average of the most recent stream flow data from the NWPP. In Avista's 1999 rate case filing (Docket No. UE-991606), the Company proposed the use of the full 60-year (1928-1988) data set available from the NWPP. A settlement stipulation in that case established normalized power supply expenses based on an average of the results from two different studies: 1) a study using the 60-year 1928-1988 record; and 2) a study using the 40-year 1948-1988 record. In the recent PSE case, the Commission approved the use of the first 50 years of the historical record, 1928-1978.

Q. Why is the hydroelectric issue so important to the Company's filing?

A. Avista is a hydro-based utility meeting approximately 50 percent of its customers' requirements from this renewable resource. Using the 60-year historical stream flow record through 1988, "normalized" hydroelectric generation is estimated at 504 average megawatts ("aMW"). A five percent difference in hydro generation, from the 504 aMW normalized level, would change proforma power supply expenses by more than $10 million (system basis), a significant amount for a company of our size.[2] Therefore, it is important that the stream flow record be based on the best estimate of normal stream flow conditions.

Q. Please describe the Company's hydroelectric projects and the historical stream flow data available for estimating historical generation levels.

A. Avista currently owns and operates two hydroelectric generating assets on the Clark Fork River, six projects on the Spokane River, and has contracts for generation from

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[1] HyReg stands for "Hydro Regulation."

four projects on the Columbia River ("Mid-C"). Our projects located on the Spokane River add 192 MW of capacity to the Company's system. The Clark Fork River projects provide about 788 MW of capacity. Finally, the Mid-C contracts can generate approximately 138 MW, bringing the Company's total hydroelectric capacity to 1,118 MW.[3]

Daily stream flow data is available back to 1891 for the Spokane River projects. Data for the Mid-C projects goes back to 1917. Our projects on the Clark Fork River, generating more than 60 percent of our hydroelectric output, only have data back to 1929. Page 1 of Exhibit No. ___(CGK-2) provides a graphical representation of annual stream flow levels for our hydro projects. I included data for The Dalles beginning in 1879 because this location on the lower Columbia River is often used as a reference, and it provides an illustration of the modest size of the stream flows on the Clark Fork and Spokane Rivers as compared to the Columbia River.

Stream flow levels can be useful for viewing possible trends in the historical data, but they do not by themselves provide the best data for estimating future hydroelectric generation. Historical stream flows must be adjusted for various sources of depletion. As the Northwest economy developed over the past 100 years, the Columbia River and its various tributaries were dammed for hydroelectric generation and flood control. Over time, environmental regulations changed how the river system was operated for power generation. Large storage reservoirs in both the United States and Canada altered the seasonal and even

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[2] $10 million = 504 aMW x 5% x $47/MWh (Average rate from AURORA model is $47/MWh).
[3] Historically, the Company's Mid-C allocation was approximately 196 MW. The expiration of our Priest Rapids contract with Grant County PUD on November 1, 2005 is responsible for the lower total in this case.

year-to-year variations in stream flow. Significant irrigation projects also were developed to divert water from the river system to raise crops.

Back-casting generation levels is therefore not simple. To complete the task, it is necessary to have data for all projects on the river system being evaluated so that good estimates may be obtained. Natural stream flows must be generated from the historical stream flow data by removing the effects described above. Natural stream flows represent the river as it would have operated absent man-made impacts. Because many locations on Northwest rivers were not measured until the 1928-29 period, it is only back to this time that regional models are able to estimate historical generation. All of the regional models developed by the U.S. Army Corps of Engineers, the Bonneville Power Administration ("BPA"), and the NWPP begin with the 1928-29 water year. The Company relies on the NWPP for its hydroelectric generation data.

Q. Please describe the variations in historical stream flow levels beginning with the 1928-29 water year.

A. To help illustrate the substantial variability in stream flows and ultimately hydroelectric generation, I've prepared a graphic included on page 2 of Exhibit No. ___(CGK-2). The bar chart shows historical stream flow for the period 1929 to 2004. Each year is expressed as a percentage of the average for the period.[4] The first decade-and-a-half of the historical record contains many water years that are well below the long-run average. The chart also shows a return, in the last decade, to multiple water years that are well below the average.

Q. What does the annual generation look like for the 60 years of available data from the NWPP model?

A. The bar chart on page 3 of Exhibit No. ___(CGK-2) shows the historical generation derived from the NWPP HyReg model for the period 1928-1988. The 60-year average generation level for Avista from the Mid-Columbia, Clark Fork and Spokane River projects is 503.7 aMW. At modeled proforma price levels (approximately $47/MWh), the estimated value for 60-year generation is $201.0 million over the proforma period.

For illustrative purposes, the following table provides comparison information related to other historical periods that will be addressed in my testimony. The 40-year average results in higher generation of over 22 aMW, because it inappropriately excludes all of the adverse hydro conditions from the period 1928-1948, and it also does not include the adverse conditions that Avista and the region experienced in the last decade, as shown on page 2 of Exhibit No._____ (CGK-2).

Comparison of Hydro Record in 2005 Case[5]

Period	Energy (aMW)	Value ($millions)	Diff. from 60-Yr. Avg. ($millions)	Diff. from 60-Yr. Avg. (percent)
NWPP 60-Year Average	503.7	$201.0	N/A	N/A
Recent 5-Year Average	464.8	$184.6	-$16.4	-8.2
40-Year Average 1948-1988	526.1	$210.1	$9.1	4.5
50-Year Average 1928-1978[6]	506.4	$202.1	$1.1	0.5

[4] The stream flow for each year reflects a weighted average of the stream flows from the Columbia River at The Dalles, the Clark Fork River and the Spokane River; weighted in proportion to the generation received from each river system.
[5] Statistics are based on the 2003-04 NWPP hydro record as described in this case, Avista's current mix of hydro resources, and market prices generated by AURORA.
[6] Period matching recent PSE Case (Docket Nos. UG-040640 and UE-040641), i.e., 1929-1978.

Although the 1928-1978 50-year average yields results that are only slightly higher than the 60-year average, it is not appropriate to selectively choose a subset of the complete record. I explain this later in my testimony.

For comparison, the five-year average hydroelectric generation level at company projects through 2004 has equaled 464.8 aMW.[7] During the last five years, the Company has experienced hydro conditions that are well below any of the long-term averages. The 2005 stream flow conditions will again challenge the Company financially. Avista expects approximately 80 percent of average generation levels for 2005, which will equate to a loss of around 100 aMW.

Q. Why does the NWPP HyReg model not develop hydroelectric generation data beyond 1988?

A. The NWPP HyReg model relies on stream flow datasets developed by BPA and other hydro-dependent Northwest utilities. Given the significant amount of work required to modify the data for use in the NWPP HyReg model, new data are made available only every 10 years. At the time the data set is updated to include an additional 10 years of data, each water year back to 1928 is adjusted to reflect irrigation levels occurring today, as well as to reflect other current uses and operations related to the river systems. At this time data are not available beyond 1988.

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[7] Historical Mid-C generation has been adjusted to reflect to reflect 2006 contract levels.

Q. Why is the Company proposing the use of the full 60-years of available stream flow data?

A. Ratemaking proceedings such as this one are intended to set base rates at a level that best approximates the future. At 50 percent reliance on hydro generation, Avista is nearly two and four times as dependent on hydroelectric generation as PSE and PacifiCorp, respectively. An error in correctly quantifying normal hydroelectric generation impacts the Company more significantly than our peers. With a heavier reliance on low-cost hydroelectric generation, it is imperative that the estimate for ratemaking purposes be as accurate as possible.

The full dataset is already in common use in the Northwest by others, and is consistent with generally accepted statistical theory. We use the full record for all of our internal analyses, from budgeting to integrated resource planning.

Using the entire record is based on sound statistical theory. For example, the Glivenko-Cantelli Theorem proves that a larger data set will better reflect the true nature of a distribution. This theorem states that as additional data is added to a distribution, there will be a convergence upon the true distribution. Put simply, more data is better than less data.

Q. Is the full 60-year data set used extensively in the Northwest?

A. Yes, Avista utilizes the full 60-year data set for all of its cost studies including: budgeting, flood control, headwater benefits, integrated resource planning, hydro investment analyses, and rate cases in Idaho. Other entities that have been surveyed in the Pacific Northwest concerning this issue also indicate that they use the full range of data available to them for planning, forecasting and marketing purposes. These entities include:

the U.S. Army Corps of Engineers (Corps), Grant County PUD, PacifiCorp, PSE, Seattle City Light, and Tacoma Power.

Q. In the recent PSE case the WUTC specifically rejected the use of a 40-year rolling average methodology. Do you agree that the 40-year rolling average should not be used?

A. Yes, we agree with the Commission's decision to move away from the 40-year rolling average. The original decision to use a 40-year rolling average was partially based on the thought that the extremely dry years of the late 1920's and 1930's may not reoccur. The recent record, as shown on page 2 of Exhibit No. ___(CGK-2), clearly shows, however, that multiple years with stream flows well below average can and will reoccur; therefore, these data should not be excluded from the record.

Furthermore, in the PSE case, Dr. Mariam (for Staff) and Dr. Dubin (for PSE) both concluded that the entire natural stream flow record was trendless, normally distributed, unable to be forecasted, and that stream flow and hydro generation are highly correlated. These points of agreement are critical to this issue because they show a consensus regarding the nature of the stream flow data. They strongly argue for the use of all available data.

Q. You mentioned earlier that the Commission adopted a 50-year study in the recently concluded PSE rate case. What was the concern with using the 60-year data set?

A. Dr. Mariam, on behalf of Staff, expressed concerns in the PSE case related to a model operated by the U.S. Army Corps of Engineers. Dr. Mariam was concerned that the hydro model was based on an assumed state of perfect foresight of future stream flow conditions that hydro operators do not in actuality benefit from. For example, the NWPP HyReg model "operates" Avista's Noxon plant in the 1988 water year knowing exactly when and how much water will flow into the reservoir. Because of this perfect stream flow information, the model is able to optimize plant operations in a way that river operators cannot; they do not have the benefit of perfect information. Operators instead have only estimates of future stream flows based on information like snow pack. Perfect information allows for the highest theoretical level of hydro generation. It is unreasonable to assume that the Company can achieve such a result.

The Commission accepted Dr. Mariam's argument for using a limited dataset, but included in its order additional language that appears to keep the door open for using the full 60-year record. The Commission, on page 51 of Order No. 06, states that "we are mindful of Dr. Dubin's testimony that all available data should be examined..."

Q. How has the Company addressed concerns with the 60-year data?

A. First, let me explain that the Company is not proposing to use the U.S. Army Corps of Engineers data set, upon which Dr. Mariam performed his analysis. The Company instead recommends the continued use of the NWPP HyReg model and its resulting data sets, as has been done for more than 20 years. We believe that because using 50 years excludes fully 20 percent of the available stream flow record, it is important to use the 60-year record. Excluding the last 10 years contradicts testimony in this and prior cases showing the importance of using all available data when forecasting hydroelectric conditions. PSE witness Dubin, in Docket Nos. UG-040640 and UE-040641 illustrated the importance of using all of the data by showing that the full 60-year dataset reduces the error of the hydro estimate by 18 percent relative to using a smaller subset of the record.

The Company concurs with Dr. Mariam that perfect foresight will allow any model to optimize its solution in a manner that is impossible in reality. However, the Company believes that the concerns raised by Dr. Mariam should be addressed without limiting the historical record, thereby enhancing the accuracy of the hydro estimate.

The NWPP HyReg model, like the U.S. Army Corps of Engineers' model, operates with perfect knowledge of actual historical stream flows. I have found that having perfect knowledge of stream flows causes generation to be overstated by 6.5 aMW on Avista's Spokane and Clark Fork River projects. To arrive at this estimate, I asked the BPA to run its similar hydro operations model with and without perfect foresight of future stream flows. I asked the federal agency to perform the study because it is the only entity in the Northwest that runs its hydroelectric model in a mode that approximates the process used by river system operators, i.e., based on what operators actually knew about stream flows at the time. Fortunately, BPA also has the ability to run its model in a mode that has perfect knowledge of future stream flows, as both the U.S. Army Corps of Engineers and the NWPP HyReg models do. Based on the two BPA datasets, I was able to calculate the generation differences on each of our river systems.

Using the full 60-year results from the NWPP HyReg model provides the best estimate of normalized hydroelectric generation levels. Using all years of the study is backed by statistical theory. As for concerns raised by WUTC staff with data from the last 10 years of the NWPP HyReg study, the Company believes that it has addressed them adequately using the results of the BPA study.

Q. Have additional adjustments have been made to the 60-year record of NWPP stream flow data, and why were those adjustments made?

A. Yes, certain adjustments are necessary to yield the proper estimate of generation from the model. These include changes to address the Model's tendency to overstate generation in high-flow periods, to account for recent upgrades at our projects, to maintain year-to-year consistency in project operations, and to allow for 2000 irrigation depletion levels.

Q. What is the cumulative impact of these adjustments?

A. The total change is a reduction in generation levels of approximately 7 aMW. A study performed by BorisMetrics identified a total net reduction in generation of 3.7 aMW for the Company's Clark Fork and Spokane River projects. Earlier Company estimates had reduced generation levels by as much as 13 aMW; however, the consultant's more comprehensive approach, combined with plant upgrade impacts, reduced the overall net impact of project spill significantly. Encroachment reduces the Company's overall Mid-Columbia output by approximately 3 aMW over the study period.[8] Although the Company

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[8] Encroachment is the impact that certain downstream hydroelectric projects' reservoirs have on the tailwater levels of upstream projects. In other words reservoir storage in a downstream project can "encroach" against the upstream project and reduce its net head and generation leveles. Encroachment impacts are accounted for through adjustments to the NWPP HyReg model results whereby upstream projects are compensated for the impacts to them created by downstream projects.

has not quantified the impact of using Continuous Mode, or 2000 irrigation depletion levels, earlier estimates indicate that the total generation change was less than one percent.[9]

IV. THE DISPATCH MODEL

Q. What modeling changes has the Company made in the calculation of normal power supply costs since from the prior general rate case?

A. In this case the Company has used the AURORA system dispatch model for the determination of power supply costs. The model optimizes the dispatch of Company-owned resources and contracts in each hour of the proforma year. Rather than using monthly average dispatch values, as was done with the model used in prior rate cases, the Dispatch Model more accurately reflects true system dispatch by evaluating future resource decisions on an hourly basis.

Q. What benefits does the Dispatch Model offer for this type of analysis?

A. There are two primary benefits. The Dispatch Model generates hourly electricity prices across the WECC, accounting for its specific mix of resources and loads. The WECC functionally operates as a single market. The Dispatch Model more accurately reflects the impact of regions outside the Northwest, limited by known transfer (transmission) capabilities. Ultimately, the Dispatch Model allows the Company to generate robust price forecasts in-house instead of relying on exogenous forecasts.

The second benefit is potentially more significant. The Company owns a number of resources, including hydroelectric plants and natural gas-fired peaking units, which have the

[9] Continuous Mode operation of the model assumes that the ending level of the reservoir for a given year is used

capability of serving customer loads during the more costly on-peak hours. By optimizing resource operation on an hourly basis, the Dispatch Model is able to more accurately value the capabilities of these assets. For example, actual 2004 on-peak prices were 14.6 percent greater than off-peak prices. By comparison, Dispatch Model on-peak prices for the proforma period averaged 14.4 percent higher than off-peak prices.

Q. Please briefly describe the Dispatch Model used to dispatch the Company's portfolio for the proforma period.

A. The AURORA Electric Market Model was developed by EPIS, Inc. of West Linn, Oregon. AURORA is a fundamentals-based tool that contains demand and resource data for all of the WECC, and employs multi-area, transmission-constrained dispatch logic to simulate real market conditions. Its true economic dispatch captures the dynamics and economics of electricity markets—both short-term (hourly, daily, monthly) and long-term. On an hourly basis the Dispatch Model develops an available resource stack, sorting resources from lowest cost to highest cost. It then compares this resource stack with forecasted load to arrive at the least-cost market-clearing price.

Q. What experience does the Company's have using AURORA?

A. The Company purchased a license to use AURORA in April of 2002. AURORA has been used for numerous studies, including the 2003 Integrated Resource Plan ("IRP") and our 2004 rate filing in the state of Idaho. AURORA will be used again for the Company's 2005 IRP.

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as the beginning reservoir level for the following year.

Q. What efforts has the Company made to make the AURORA model available to Commission Staff?

A. The license negotiated by the Company for AURORA was structured so that it is extended to Washington and Idaho Commission Staff. Members of both Commission Staffs attended the initial user training session with Company staff in 2002, and have attended AURORA conferences where modeling topics were discussed and additional training was provided. Each annual license renewal provides for an additional two days of on-site training, which is available to Commission Staff upon request.

Training on the latest version of AURORA was made available to Commission Staff from Washington and Idaho in March 2004. The two-day training session was held in Olympia at WUTC headquarters and was specifically focused on Avista's resources and loads. WUTC Staff members Hank McIntosh and Yohannes Mariam attended the training.

V. ASSUMPTIONS AND CALCULATIONS

Q. Are the assumptions utilized for the Dispatch Model in this proceeding similar to those used in the 2003 IRP filed with this Commission?

A. Yes, with a few exceptions. First, forward market natural gas prices change over time. Given the importance of this variable in setting wholesale electricity prices, the forecast has been updated to reflect more recent forward market prices. To ensure that AURORA forecasted electricity prices are similar to 2006 forward prices, the Company used AURORA bidding factors logic in the runs, which I will explain later in my testimony. Third, Colstrip fuel prices are modified to reflect actual mining budgets. The Kettle Falls fuel price is also modestly different from the IRP, and reflects updated calculations based on multiple contracts in place with fuel suppliers and existing inventory. Avista loads were updated to reflect weather-adjusted 2004 actual values, excluding Potlatch Corporation's 2004 net load. Finally, a few modifications were made to reflect changes in our resource portfolio since the time of the 2003 IRP. The changes were: 1) a synthetic contract to reflect Company obligations to provide third-party reserves, 2) the addition of our 35 MW wind contract with PPM, 3) the inclusion of one-hundred percent of the Coyote Springs 2 plant; and 4) the adjustments to the output of our hydroelectric plants described in the previous section.

Q. How does the Dispatch Model operate the Company's hydroelectric projects?

A. The model begins by "peak-shaving" loads using hydro resources. It determines which hours represent the highest loads and allocates to them as much hydroelectric energy as possible. Because the Company's hydroelectric projects have historically generated more of their energy during the on-peak hours relative to average hydroelectric projects across the Northwest, the Company uses a 5-year average dispatch shape through 2003 to ensure Company-owned projects are operated in a manner that reflects historical operations.[10] Over the proforma period, the Dispatch Model dispatches 68.4 percent of the Company's hydro generation during on-peak hours. Since on-peak hours

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[10] For each month, average generation is calculated across the period for each clock hour. This results in 12 sets of 24-hour data, one for each calendar month. The sets are then divided by the average generation during corresponding historical months. The resulting percentages are then used to dispatch Company-owned hydroelectric plants for the corresponding month of the proforma period. This method is applied to the Company's hydro basins separately (Clark Fork, Spokane, and Mid-C).

represent only 57 percent of the year, this demonstrates a substantial shift of hydro resources to the more expensive on-peak hours.

Q. How does the Dispatch Model's utilization of Company hydro resources compare to actual history at the plants?

A. As explained above, over the proforma period the Dispatch Model shapes 68.4 percent of available hydroelectric energy into the on-peak hours. This compares with a 5-year average through 2003 of 67.7 percent, and an average since 1989 of 68.1 percent.

Q. On a broader scale, what calculations is the Dispatch Model performing?

A. The Dispatch Model's goal is to minimize overall system operating costs across the WECC, including Avista's portfolio of loads and resources. The dispatch model generates a wholesale electric market price forecast by evaluating all resources in the WECC simultaneously in a least-cost equation to meet regional loads. As the Dispatch Model progresses from hour to hour, it "operates" those resources necessary to meet load. With respect to the Company's portfolio, the Dispatch Model tracks the hourly output and fuel costs associated with the Company's generation. It also calculates, on an hourly basis, energy quantities for the Company's contractual rights and obligations. In every hour the Company's loads and obligations are compared to determine a net position. This position is then balanced using the simulated wholesale electricity market. The cost of energy purchased from the market or the value of energy sold into the market are calculated based on the electric market-clearing price for the specified hour.

The thermal fuel costs and market transaction values from the Dispatch Model are provided to Witness Johnson, where he adds other resource and contract revenues and expenses to determine the net power supply expense.

Q. How does the Dispatch Model determine electric market prices, and how are they used to calculate market purchases and sales?

A. The Dispatch Model calculates electricity prices for the entire WECC, separated into various geographical areas such as the Northwest and Southern California. The load in each area is compared to available resources, including available transmission, to determine the price for each hour. Ultimately, the market price for the hour is set based on the last resource in the stack to be dispatched. This resource is referred to as the "marginal resource." Given the prominence of natural gas-fired resources on the margin, this fuel is a key variable in the determination of hourly wholesale electricity prices.

Q. What is the Company assuming for natural gas prices in the proforma period?

A. Natural gas prices are a function of average commodity cost, transportation, and taxes where applicable. For the proforma period, natural gas prices were set using an average of witnessed forward prices for calendar year 2006 during the six-month period ending February 10, 2005. Separate averages were calculated for each of the Company's natural gas-fired plants, as well as for Henry Hub. Although the Company doesn't dispatch any of its plants using gas indexed to Henry Hub, AURORA uses Henry Hub as a basis for dispatching other natural gas-fired resources in the WECC. Due to the varied locations of our plants, the average price for the period ranges from a low of $5.858 per decatherm at

Rathdrum, to a high of $6.143 per decatherm for Northeast, Boulder Park, and the Kettle Falls CT. The average price at Coyote Springs 2 is $5.938 per decatherm. For comparison, the average Henry Hub price for the period is $6.337 per decatherm. See Table 1 in the following section for a listing of the monthly natural gas prices assumed for each of the Company's gas-fired plants.

Q. Please describe bidding factors and explain why the Company chose to use them in the AURORA Model?

A. Bidding factors are a powerful capability within AURORA that can be used to address market abnormalities that are not otherwise captured in the optimization process. Bidding factors are used to increase or decrease the dispatch (variable) cost of a generator. A bidding factor can force a generator into the market without earning a profit or restrict it from entering the market by adding a profit margin. For example, a bidding factor of 5 percent will increase a generator's $30.00 dispatch price to $31.50. A bidding factor of –5 percent will decrease the same generator's dispatch price to $28.50.

Accurately forecasting market prices is important to ensure net power supply expense levels are reasonable. Overstating prices in a month where the Company is short will overstate power supply expenses. In the case where the Company is long, high prices will overstate the value of generation and artificially lower rates.

Based on preliminary runs, the Company found that AURORA was over-estimating forward electricity prices by approximately 4 percent over the proforma period, as compared to actual forward electric prices. Monthly discrepancies ranged between plus and minus 20 percent. The Company used bidding factors to align the AURORA forecast of monthly Mid-

Columbia electricity prices for 2006 with actual forward market prices for 2006. With the use of bidding factors, both natural gas and electricity prices were aligned with the forward marketplace prior to valuation of the Company's generating assets and contracts.

Q. How were bidding factors calculated and to which generators were they applied?

A. Bidding factor calculations were developed over several iterations of simulating the Western Interconnect in AURORA. The factors were applied equally to all generators in the WECC. Iterations were performed until modeled market prices came to within approximately $1.00 of the forward market each month. The following table shows AURORA market prices before and after the use of bidding factors, and compares them to forward market prices over the same period from which natural gas prices were obtained. The average price difference falls to less than 10 cents from the forward price under the bidding factor run compared to a difference of $1.71 without bidding factors.

AURORA Forecast Comparison

Month	Forward CSII Gas Prices ($/dth)	Forward NE/BP/ KFCT Gas Prices ($/dth)	Forward Rathdrum Gas Prices ($/dth)	Forward Electricity Prices ($/MWh)	AURORA Without Bidding Factors ($/MWh)	Difference From Forwards ($/MWh)	AURORA With Bidding Factors ($/MWh)	Difference From Forwards ($/MWh)
Jan-06	6.741	6.977	6.661	56.17	54.98	(1.20)	55.95	(0.22)
Feb-06	6.712	6.948	6.632	53.38	52.35	(1.03)	53.27	(0.11)
Mar-06	6.513	6.740	6.433	47.82	57.74	9.92	48.10	0.28
Apr-06	5.704	5.899	5.624	41.30	44.02	2.72	41.72	0.42
May-06	5.556	5.745	5.476	33.28	39.71	6.43	33.64	0.36
Jun-06	5.572	5.762	5.492	32.77	25.58	(7.18)	32.15	(0.62)
Jul-06	5.594	5.784	5.514	45.46	46.32	0.87	45.15	(0.30)
Aug-06	5.617	5.809	5.537	52.88	51.81	(1.07)	52.81	(0.07)
Sep-06	5.596	5.787	5.516	49.90	52.42	2.52	50.17	0.27
Oct-06	5.624	5.816	5.544	46.73	53.44	6.70	46.87	0.14
Nov-06	5.909	6.112	5.829	49.12	51.50	2.38	50.17	1.05
Dec-06	6.167	6.381	6.087	52.68	52.09	(0.59)	52.55	(0.14)
Average	5.938	6.143	5.858	46.79	48.50	1.71	46.88	0.09

VI. RESULTS

Q. What specific outputs from the Dispatch Model are used for ratemaking?

A. The Dispatch Model tracks the Company's portfolio during each hour of the proforma study. Fuel costs and generation for each resource are summarized by month. Total market sales and purchases, and their revenues and costs, are also determined. These values are provided to Witness Johnson for his calculations of total power supply expense; they are contained in Exhibit No. ___(CGK-3). Page 1 of the exhibit also contains a monthly summary of modeled energy for each of our contracts.

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

A. Yes, it does.