RECEIVED
2008 APR -3 PM 12:55
IDAHO PUBLIC
UTILITIES COMMISSION

DAVID J. MEYER
VICE PRESIDENT, GENERAL COUNSEL, REGULATORY &
GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO)	CASE NO. AVU-E-08-01 DIRECT TESTIMONY OF CLINT G. KALICH

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

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 graduated from Central Washington University in 1991 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 of 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 accepted my current position, assisting the Company in 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. My testimony will describe the Company's use of the $\text{AURORA}_{\text{XMP}}$ dispatch model, hereinafter referred to as the "Dispatch Model." I will explain the key assumptions driving the Dispatch Model's market forecast of electricity prices. The discussion includes the variables of natural gas, Western Interconnect loads and resources, and hydroelectric conditions. I will describe how the model dispatches our resources and contracts in a manner that maximizes benefits to customers and tracks their values for use in pro forma calculations. Finally, I will present the modeling results provided to Company Witness Mr. Johnson for his power supply pro forma adjustment calculations.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 5, Schedules 1 and 2. Schedule 1 provides a forecast of Company load and resource positions from 2009 through 2018. Schedule 2 provides summary output from the $\text{AURORA}_{\text{XMP}}$ dispatch model. All information contained in the exhibit was prepared under my direction.

II. THE DISPATCH MODEL

Q. What model is the Company using to dispatch its portfolio of resources and obligations?

A. The Company uses EPIS, Inc.'s $\text{AURORA}_{\text{XMP}}$ system dispatch model ("Dispatch Model") for determining power supply costs. The model optimizes dispatch of Company-owned resources and contracts in each hour of the pro forma year. The pro forma period is January 1, 2009 through December 31, 2009. It reflects true system operations by evaluating future resource decisions on an hourly basis.

Q. What AURORA version and database is the Company using for this case?

A. The Company is using AURORA$_{XMP}$ version 9.0., released in November 2007, and the latest available database for it (North_American_DB_2007-02).

Q. Please briefly describe the Dispatch Model.

A. The AURORA$_{XMP}$ electric market model was developed by EPIS, Inc. of Sandpoint, Idaho. AURORA$_{XMP}$ is a fundamentals-based tool containing demand and resource data for the entire Western Interconnect. It employs multi-area, transmission-constrained dispatch logic to simulate real market conditions. Its true economic dispatch captures the dynamics and economics of electricity markets. On an hourly basis the Dispatch Model develops an available resource stack, sorting resources from lowest to highest cost. It then compares this resource stack with load obligations in the same hour to arrive at the least-cost market-clearing price for the hour. Once resources are dispatched and market prices are determined, the Dispatch Model singles out Avista resources and loads and values them against the marketplace.

Q. What experience does the Company have using AURORA$_{XMP}$?

A. The Company purchased a license to use AURORA$_{XMP}$ in April 2002. AURORA$_{XMP}$ has been used for numerous studies, including the Company's 2003, 2005, and 2007 Integrated Resource Plans ("IRPs"), our 2004 general rate case filing in this state, and our 2005, 2007, and 2008 general rate case filings before the Washington Utilities and Transportation Commission ("WUTC"). The tool is also used for various resource evaluations, including requests for proposals.

Q. Who else uses AURORA$_{XMP}$?

A. AURORA$_{XMP}$ is used all across North America. In the Northwest specifically, AURORA$_{XMP}$ is used by the Bonneville Power Administration, the Northwest Power and Conservation Council, Puget Sound Energy, Idaho Power, Portland General Electric, Seattle City Light, Grant County PUD, and Tacoma Power, among others.

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

A. The Dispatch Model generates hourly electricity prices across the Western Interconnect, accounting for its specific mix of resources and loads. The Dispatch Model reflects the impact of regions outside the Northwest on Northwest market prices, limited by known transfer (transmission) capabilities. Ultimately, the Dispatch Model allows the Company to generate price forecasts in-house instead of relying on exogenous forecasts.

The Company owns a number of resources, including hydroelectric plants and natural gas-fired peaking units, which serve customer loads during more valuable on-peak hours. By optimizing resource operation on an hourly basis, the Dispatch Model is able to appropriately value the capabilities of these assets. For example, actual 2006 on-peak prices were 31.9% higher than off-peak prices. In 2007 the difference was 29.9%. For comparison, Dispatch Model on-peak prices for the pro forma period average 30% higher than off-peak prices. In summary, the Dispatch Model appropriately values the energy from Avista's resources during on-peak periods in a manner similar to that recently experienced in the Northwest region.

Q. On a broader scale, what calculations are being performed by the Dispatch Model?

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

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

A. The Dispatch Model calculates electricity prices for the entire Western Interconnect, separated into various geographical areas such as the Northwest and Northern and Southern California. The load in each area is compared to available resources, including resources available from other areas that are linked by transmission corridors, to determine the electricity price in each hour. Ultimately, the market price for an 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 wholesale electricity prices.

Q. How does the Dispatch Model operate regional hydroelectric projects?

A. The model begins by "peak shaving" loads using system hydro resources. When peak shaving, the Dispatch Model determines which hours contain the highest loads and allocates to them as much hydroelectric energy as possible. Remaining loads are then met with other available resources.

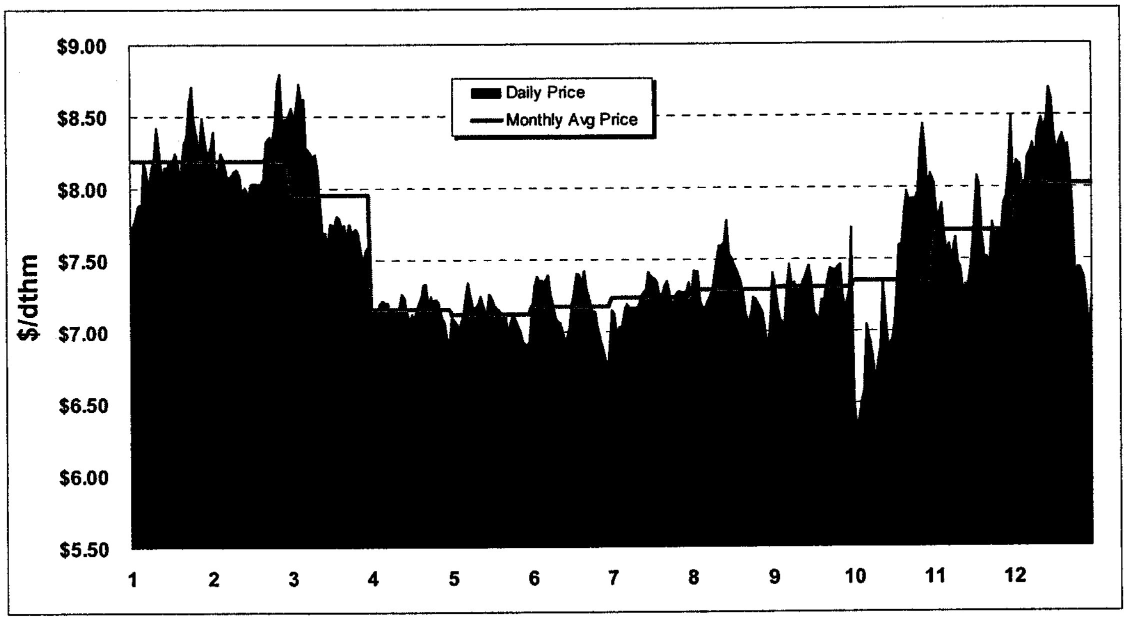
Q. Has the Company made any modifications to the database for this case?

A. Yes. Avista's portfolio of resources is modified to reflect actual operating characteristics, natural gas prices are modified to match projected forward prices over the pro-forma period, regional resources are modified where better information is known, and northwest hydro data is replaced with Northwest Power Pool data.

Q. Please describe your update to pro forma period natural gas prices.

A. Natural gas prices for this filing are based on a 3-month average of 2009 monthly forwards from October 1, 2007 to December 31, 2007. This method is consistent with our present case before the WUTC. Prices are fitted to a daily shape based on daily spot market prices at AECO between January 2003 and December 2007. Daily and monthly gas price shapes at AECO are shown in Chart No. 1. Other basins retain the same daily shape.

Chart No. 1 - Daily Natural Gas Price Shape at AECO



Natural gas prices are modified to ensure prices across the Western Interconnect are consistent with changes made to the Northwest. Annual average natural gas prices at the various trading hubs are presented below in Table No. 1.

Table No. 1 - Pro Forma Natural Gas Prices

Basin	Price ($/dth)	Basin	Price ($/dth)
AECO	7.55	Stanfield	7.92
Malin	7.99	Sumas	8.15
Spokane	8.28	Henry Hub	8.36
Rockies	7.02	Topock	7.97

Q. What hydro record is the Company using in this filing?

A. The Company bases this case on the 50-year hydrological record beginning in 1929. As with natural gas, this method is consistent with our present case before the WUTC. The Dispatch Model is run one time for each hydroelectric year, with the average of all 50 being used to set power supply expenses.

Data is sourced from the Northwest Power Pool's (NWPP) 2006-07 Headwater Benefits Study. This study is the latest available.

Q. How does Coyote Springs 2 dispatch relate to historical dispatch?

A. Coyote Springs 2 was modified from the default database to more accurately simulate actual plant operations. Chart No. 2 shows actual Coyote Springs 2 dispatch for calendar year 2007.

Chart No. 2 - CS2 Dispatch (Calendar Year 2007 Actual)

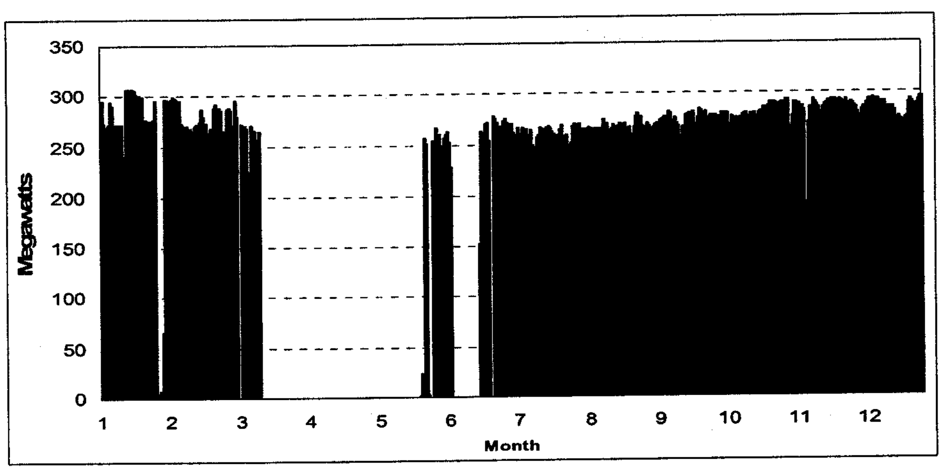
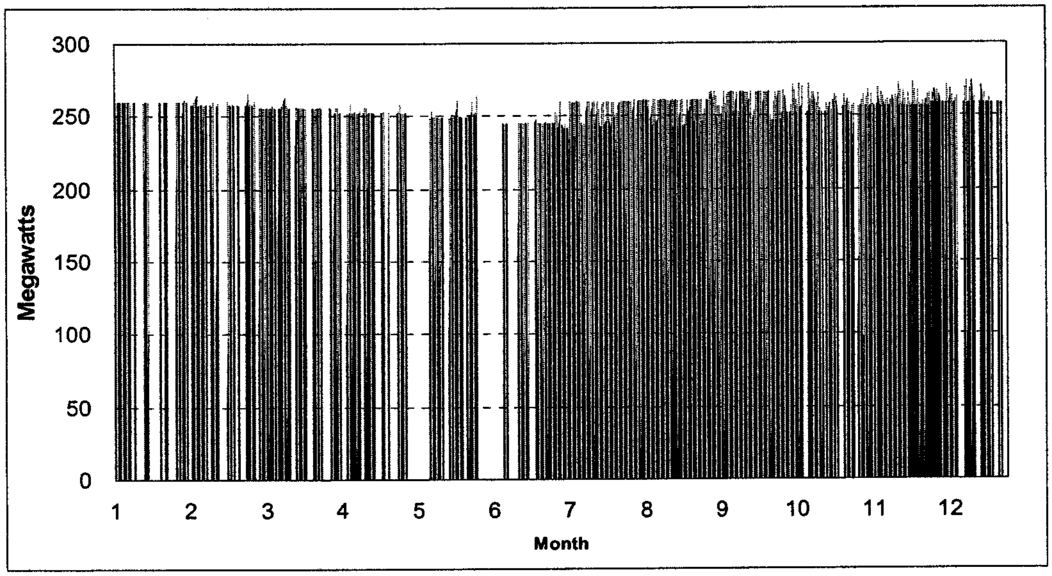


Chart No. 3 shows Coyote Springs 2 during the 2009 pro forma period prior to modifying database assumptions.

Chart No. 3 - CS2 Dispatch (2009 Pro Forma with AURORA$_{XMP}$ default logic)



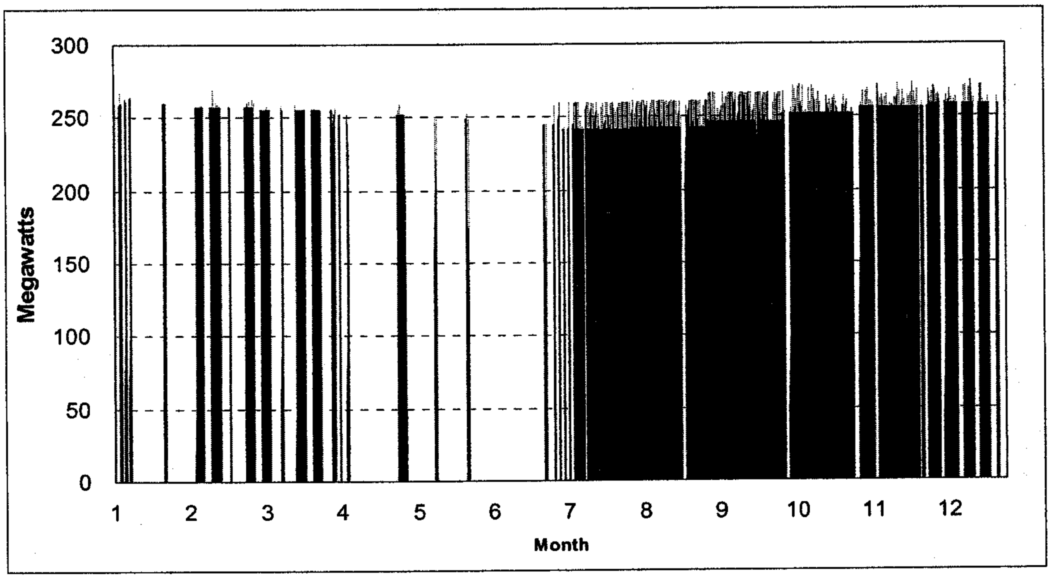
The Dispatch Model using EPIS' default database starts and shuts down Coyote Springs 2 nearly every day (269 starts), and the plant generates 121 aMW. This operational pattern is not realistic and is beyond the operational capability of Coyote Springs 2. To resolve this modeling challenge, the Company modified the start-up cost, start-up fuel, minimum up and minimum down times for the plant. This same methodology was tested for all Western Interconnect combined cycle plants, but such modification had an adverse effect on the overall on/off peak price spread, resulting in a much higher differential than witnessed historically or that is present in the forward markets. Avista continues to work with EPIS, the developer of $AURORA_{XMP}$, to address our concerns with overall CCCT plant dispatch across the Western Interconnect.

Start-up costs were identified as a key driver to the incorrect dispatch behavior of Coyote Springs 2. The EPIS default start-up cost for Coyote Springs 2 is $12.61 per MW start-up cost, or $3,429. Based on our experience, this cost is low by orders of magnitude. Based on Company experience each cold start at Coyote Springs 2 includes 1,891 decatherms of fuel and $10,000 of estimated O&M costs. Assuming the average annual Stanfield natural gas price of $7.92 per decatherm, the start up costs is estimated to be $24,977 (1,891 x $7.92 + $10,000).

The second modification made by the Company was to change the minimum up and minimum down times from 16 hours and 8 hours respectively, to 20 hours up an 20 hours down. Minimum up time, not only indicates how long the unit must stay on-line, but also is used to allocate start-up costs for commitment decisions.

These two changes, when taken together, provide for a much more reasonable dispatch of Coyote Springs 2, as shown in Chart No. 4.

Chart No. 4 - CS2 Dispatch (2009 Pro Forma Average Hydro)



Q. How does the Dispatch Model Operate Company-controlled hydroelectric generation resources?

A. The Dispatch Model treats all hydroelectric generation plants within a load area as a single large plant. The Company's hydroelectric plants are on average, however, more flexible than the average plant used in each load area. To account for this additional flexibility, the Company algebraically extracts its plants from the region and develops individual hydro operations logic for them. Company-controlled hydroelectric resources are separated into three river systems: the Spokane River, the Clark Fork River, and individually separate the Mid-Columbia projects. This separation ensures that the flexibility inherent in these resources is credited to customers in the pro forma exercise.

Q. Please compare the operating statistics from the Dispatch Model to recent historical hydroelectric plant operations.

A. Over the pro forma period the Dispatch Model generates 66.9% of the Company's hydro generation during on-peak hours (based on average water). Since on-peak hours represent only 57% of the year, this demonstrates a substantial shift of hydro resources to the more expensive on-peak hours. This is nearly identical to the 5-year average of on-peak hydroelectric generation through 2007: 66.4%.

Q. What is the Company assuming for natural gas prices in the pro forma period for Company-owned gas-fired resources?

A. Natural gas prices are a function of average commodity cost, transportation, and applicable taxes. Consistent with our last general rate case filing, natural gas prices were set using an average of witnessed forward prices, specifically the three-month period ending December 31, 2007. The average price for the pro forma year equals \$7.92 per decatherm at Rathdrum and CS2, and \$8.28 per decatherm for Northeast, Boulder Park, and the Kettle Falls CT.

Q. Please provide a summary of the monthly and average Northwest Forward natural gas and electricity prices?

A. Table No. 2 presents modeled natural gas and electricity prices.

Table No. 2 - Dispatch Model Prices Comparison

Month	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Mid-C ($/MWh)	Month	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Mid-C ($/MWh)
Jan-09	8.594	8.988	57.95	Jul-09	7.574	7.927	57.90
Feb-09	8.599	8.993	62.66	Aug-09	7.626	7.981	65.03
Mar-09	8.357	8.741	58.97	Sep-09	7.643	7.999	61.49
Apr-09	7.497	7.846	52.12	Oct-09	7.688	8.046	59.02
May-09	7.455	7.803	47.25	Nov-09	8.068	8.441	63.09
Jun-09	7.508	7.858	41.33	Dec-09	8.393	8.779	62.04
				Average	7.92	8.28	57.39

Q. Are Mid-Columbia electric prices from the Dispatch model the same as the Forward Market?

A. No, Mid-Columbia electric prices from the Dispatch Model differ from the forward market for a variety of reasons. The forward market prices are not only an expectation of future prices, but they contain an adjustment for risk or unknown future conditions, based on the premise you can "lock in" prices. The Dispatch Model is a spot market model that forecasts prices for a specific time in the future given load, hydro, and fuel price conditions. Average annual Mid-Columbia prices in the forward market are $68.38/MWh on-peak and $54.25/MWh off-peak (based on average forwards between 10/1/2007 and 12/31/2007). The average Mid-Columbia price from the Dispatch Model is $63.68/MWh on-peak and $48.99/MWh off-peak.

Q. You stated earlier in your testimony that you are using the NWPP hydro study as the basis for your hydro dataset. Does the NWPP study include the Cabinet Unit 4 or the Noxon Rapids 4 upgrade?

A. No, the NWPP study does not include the Cabinet Unit 4 or Noxon Rapids 4 upgrades. The data will be included in our next data submittal to the NWPP. I expect the upgrade to be reflected in the 2008 NWPP study.

Q. How have you accounted for the Cabinet Unit 4 and Noxon Rapids 4 upgrades in the pro forma?

A. The Cabinet Unit 4 upgrade is expected to generate 1.98 average megawatts and Noxon Rapids 4 is expected to generate 2.33 average megawatts of additional energy in an average water year. To account for this energy in the pro forma, the unit sizes are increased from 55.2 MW to 59.7 MW and 105 MW to 111.4 MW, respectively. The Dispatch Model then generates at the upgraded energy and capacity levels when the units are dispatched.

Q. Please explain how the upgrades to Colstrip Units 3 and 4 are reflected in the Dispatch Model.

A. The Company increased the generation capability of each unit from 740 MW to 768 MW. This change allows the Dispatch Model to correctly value the entirety of each plant in the wholesale marketplace. Our resource portfolio tracked in the Dispatch Model contains a 15% share of each unit. With the overall capacity of each resource increased, our 15% allocation increases proportionally and lowers the overall cost of our generation portfolio.

III. RATE PERIOD LOAD ADJUSTMENT

Q. Why is the company proposing using 2009 pro forma retail loads in this case?

A. The intent of each rate proceeding is to develop a reasonable projection of costs the company expects to incur during the period over which rates are set. Though historical data are used as the starting point, adjustments are made where that history does not provide accurate revenues and expenses for the period new rates will be in effect. For example, in the power supply category alone, pro forma adjustments are included to reflect expected conditions in 2009 for hydroelectric plant upgrades, fuel prices, and contracts that were not in the historical test year.

Q. Please explain the source used for 2009 pro forma loads?

A. Each year the Company develops a 25-year load forecast by rate class (residential, commercial, industrial, and street lighting). The load projection is used by many departments throughout the utility. It is the basis for power supply budgeting, revenue forecasting by our finance department, and for our Integrated Resource Plans (IRPs). During the natural gas and electric IRP processes the forecast is reviewed both internally by senior management as well as by external parties that include Idaho and Washington Commission staff members.

The rate period loads used in this case are taken from the Company's 2008 load forecast completed in July 2007. The 2009 load value is 1,061.2 aMW. As this load is generated using "normal weather," it eliminates the need for any weather-normalization adjustment.

Q. Are Avista's rate period loads based on quantitative methods?

A. Yes. For the residential, small and large general service, pumping and street light customers, the methodology is based on mathematical relationships between growth in the economy of the service area and the energy used by customers. Very large general service customer (e.g., hospitals, universities, manufacturers) forecasts rely on trends in these segments combined with regular discussion with the individual customers regarding expansion (or contraction) plans.

Q. How does Avista acquire service area economic forecasts?

A. Avista contracts with Global Insight, Inc., a national economic forecasting consulting company also used by agencies in the states of Idaho, Oregon and Washington to provide county-level projections of job, population, and personal income growth rates. These have been shown to be the primary drivers of electricity consumption. Global Insights, Inc. also provides projections for interest rates, oil prices, the consumer price index, and other factors used to project customer growth and customer consumption.

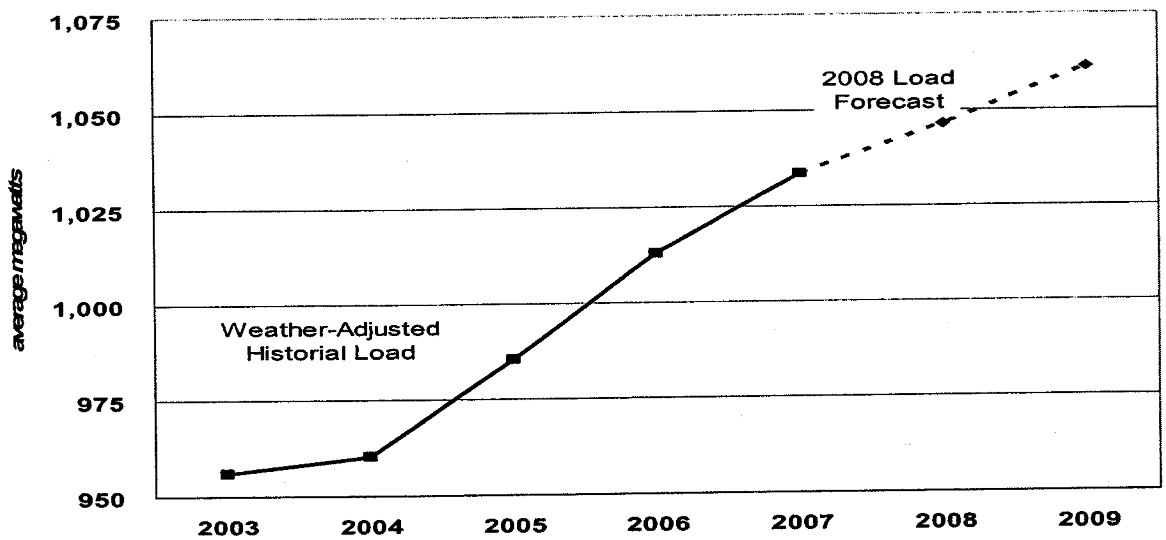
Q. Does Avista include the impact of conservation and electricity prices when projecting future electricity load?

A. Yes. The load forecast incorporates changes to mathematical relationships for conservation programs, changes in electricity prices, and other factors. As efficiency standards for building shells, motors, glazing, appliances and lighting have changed over time, they are incorporated in the forecast. Net growth in Avista's load occurs not only by newly constructed buildings, but also by increases and decreases in the amount of equipment or intensity of use of the existing customer base.

Q. How do 2009 pro forma period loads compare with recent results?

A. Chart No. 5 shows historical and forecast utility load changes. As the table illustrates, our 2008 forecast of retail load follows a trend line consistent with recent history.

Chart No. 5 - System Loads Absent Potlatch Cogeneration

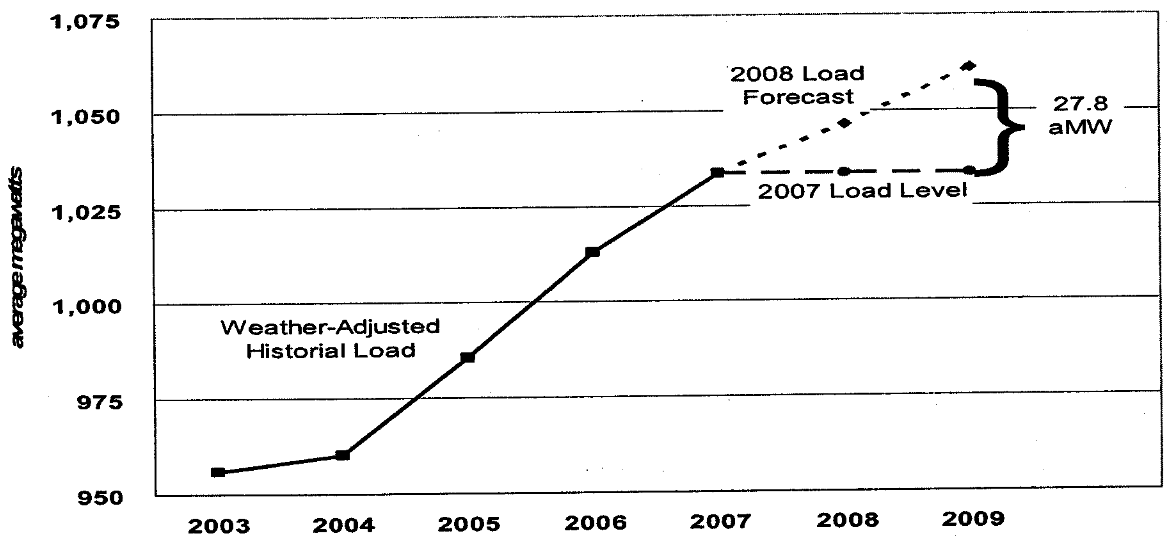


Q. What is the significance of using the forecasted pro forma load estimate for ratemaking purposes?

A. Chart No. 6 builds on information presented in Chart No. 5. It illustrates why 2007 load levels should not be used to set rates for calendar year 2009: using 2007 weather-adjusted actual loads would assume the Company will experience no load growth for two calendar years.

This would be at odds with recent history and any reasonable load growth assumption, especially given the continued growth in the economy in our Company's service area. Pro forma load levels will be approximately 28 aMW above 2007 historical loads.

Chart No. 6 -System Loads Absent Potlatch Cogeneration, with 2007 Load



Q. Does the difference between pro forma and actual loads get tracked through the Power Cost Adjustment (PCA) mechanism?

A. Yes. As explained more fully by Mr. Johnson, when actual 2009 loads differ from the pro forma, the difference between the two values is tracked through the PCA, with additional or reduced sales being adjusted through the Retail Revenue Credit.

The use of 2009 pro forma loads in this case, together with the production property adjustment (discussed by Company witness Ms. Knox), <u>provides a more accurate basis to set retail rates for the period that new retail rates will be in effect.</u>

Q. What is the Company's present loads and resources position?

A. The Company's latest energy and capacity loads and resources tabulations ("L&Rs") are attached in Exhibit No. 5, Schedule 1. As the L&Rs show, 2009 loads are expected to equal 1,118.5 aMW. For this filing the figure is reduced by the 5-year average of self-generation of the Potlatch Corporation. This adjustment lowers the pro forma load to 1,061.2 aMW.

Chart No. 7 below details the Company's load and resource energy position from 2009 through 2018. The chart excludes 57.3 aMW of Potlatch load, as well as its 57.3 aMW of PURPA generation.

Chart No. 7 - Avista 2009-2018 Load and Resource Energy Position (aMW)

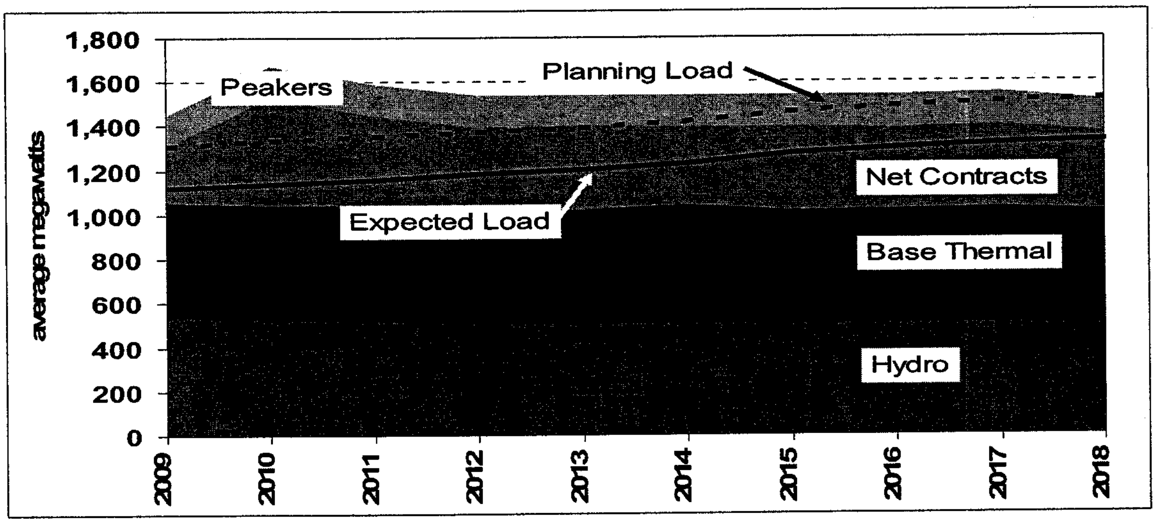
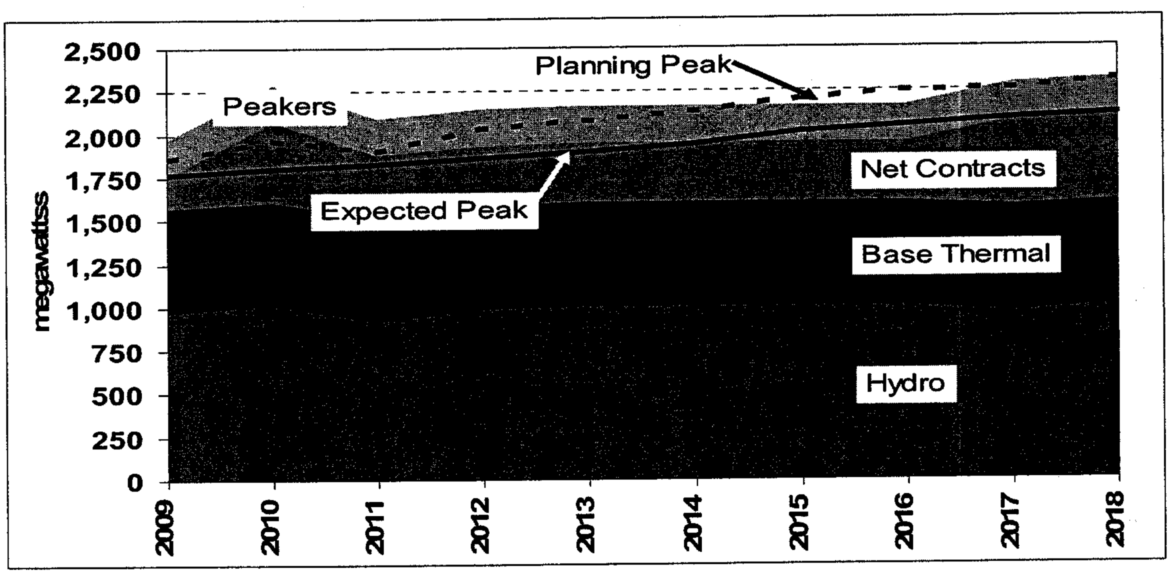


Chart No. 8 presents the Company's load and resource capacity position from 2009 through 2018. As with Chart No. 7, a 57.3-MW reduction is applied both to load and contracts to reflect Potlatch.

Chart No. 8 - Avista 2009-2018 Load and Resource Capacity Position (MW)



IV. RESULTS

Q. Please summarize the results from the Dispatch Model that are used for ratemaking.

A. The Dispatch Model tracks the Company's portfolio during each hour of the pro forma 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 and summarized by month. These values are contained in Exhibit No. 5, Schedule 2 and was provided to Mr. Johnson for use in his calculations. Mr. Johnson adds resource and contract revenues and expenses not accounted for in the Dispatch Model (e.g., fixed costs) to determine net power supply expense.

Q. Company witness Mr. Morris explains in his pre-filed testimony that the Company has included a special "rate mitigation adjustment" to power supply expenses. How did you account for this adjustment in your results?

A. As Mr. Morris explains in his testimony, the purpose of this adjustment is to reduce the overall rate increase resulting from this rate filing.

The "rate mitigation adjustment" is achieved through increasing the amount of hydroelectric energy available to the Company in the Dispatch Model during the proforma period. Exhibit No. 5, Schedule 2 contains an "Avista Hydro Adjustment" of 26.5 aMW, as can be seen on line 23 of the applicable page. This energy is included in the proforma at zero cost, thereby increasing the Company's energy sales into the wholesale marketplace. The total cost reduction is $12.8 million on a system basis.

During the period that new retail base rates will be in place from this general rate case, 90% of this mitigation adjustment will be tracked through the PCA, and the Company will absorb 10%.

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

A. Yes, it does.

DAVID J. MEYER
VICE PRESIDENT, GENERAL COUNSEL, REGULATORY &
GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851

RECEIVED
2008 APR -3 PM 12:55
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-08-01 EXHIBIT NO. 5 CLINT G. KALICH

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Exhibit 5

Avista Utilities Loads and Resources Position—Energy Tabulation

AVERAGE LOAD & HYDRO PLANNING

	REQUIREMENTS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	System Load	-1,118	-1,141	-1,161	-1,182	-1,202	-1,229	-1,274	-1,299	-1,316	-1,333
2	Contract Obligations	-141	-140	-140	-139	-139	-139	-64	-64	-12	-12
3	Total Requirements	-1,259	-1,281	-1,300	-1,322	-1,342	-1,369	-1,338	-1,364	-1,328	-1,345
	RESOURCES										
4	Contract Rights	387	625	542	508	516	495	441	431	389	366
5	Hydro	537	523	521	505	505	505	505	505	505	502
6	Thermal Resources	522	523	523	522	521	537	512	521	523	514
7	Total Resources	1,447	1,671	1,586	1,535	1,543	1,536	1,459	1,457	1,417	1,382
8	**POSITION**	**188**	**390**	**286**	**213**	**201**	**168**	**121**	**94**	**89**	**37**
	CONTINGENCY PLANNING										
9	Contingency Total	-191	-191	-191	-187	-187	-187	-187	-187	-187	-187
10	Peaking Resources	142	142	142	142	133	142	142	142	142	142
11	**CONTINGENCY NET POSITION**	**139**	**341**	**237**	**168**	**147**	**123**	**76**	**49**	**44**	**-8**
12	**POSITION EXCLUDING MAINT.**	**167**	**368**	**264**	**197**	**185**	**136**	**114**	**78**	**71**	**30**

Avista Utilities Loads and Resources Position—Capacity Tabulation

PEAK LOAD AND RESOURCE PLANNING

	REQUIREMENTS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	Native Load	-1,764	-1,800	-1,831	-1,865	-1,900	-1,944	-2,010	-2,052	-2,081	-2,109
2	Contracts Obligations	-242	-242	-242	-242	-242	-242	-167	-167	-17	-17
3	Total Requirements	-2,006	-2,042	-2,073	-2,107	-2,141	-2,186	-2,177	-2,218	-2,097	-2,125
	RESOURCES										
4	Contracts Rights	427	708	608	590	590	590	515	515	515	515
5	Hydro Resources	971	1,013	917	989	1,003	1,003	1,003	1,003	976	1,003
6	Base Load Thermals	602	597	602	602	602	602	602	602	602	602
7	Peaking Units	211	211	211	211	211	211	211	211	211	211
8	Total Resources	2,210	2,529	2,336	2,391	2,406	2,406	2,331	2,331	2,303	2,331
9	**PEAK POSITION**	**204**	**487**	**264**	**284**	**264**	**220**	**154**	**112**	**206**	**205**
	RESERVE PLANNING										
10	Planning Reserve Margin	-266	-270	-273	-277	-280	-284	-291	-295	-298	-301
11	**RESERVE PEAK POSITION**	**-63**	**217**	**-9**	**8**	**-16**	**-65**	**-137**	**-183**	**-92**	**-96**
12	**POSITION EXCLUDING MAINT.**	**112**	**324**	**198**	**115**	**84**	**35**	**-38**	**-83**	**35**	**4**

Exhibit 5

AURORA$_{XMP}$ Summary Output—Project Generation (GWh)

	Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hydro Projects													
Clark Fork	2,838.1	181.8	190.7	174.3	262.5	479.0	485.3	335.6	181.7	119.7	103.9	118.6	205.0
Cabinet Gorge	912.3	58.5	61.3	56.0	84.4	154.0	156.0	107.9	58.4	38.5	33.4	38.1	65.9
Noxon Rapids	1,925.8	123.4	129.4	118.3	178.1	325.0	329.3	227.7	123.3	81.2	70.5	80.4	139.1
TOTAL	*2,838.1*	*181.8*	*190.7*	*174.3*	*262.5*	*479.0*	*485.3*	*335.6*	*181.7*	*119.7*	*103.9*	*118.6*	*205.0*
Spokane River	1,113.0	104.1	97.5	120.1	123.6	127.6	113.8	73.8	41.0	56.1	71.5	86.3	97.6
Little Falls	223.7	20.9	19.6	24.1	24.8	25.6	22.9	14.8	8.2	11.3	14.4	17.3	19.6
Long Lake	445.5	41.7	39.0	48.1	49.5	51.1	45.5	29.5	16.4	22.5	28.6	34.5	39.1
Monroe Street	92.1	8.6	8.1	9.9	10.2	10.6	9.4	6.1	3.4	4.6	5.9	7.1	8.1
Nine Mile	176.5	16.5	15.5	19.0	19.6	20.2	18.0	11.7	6.5	8.9	11.3	13.7	15.5
Post Falls	111.8	10.5	9.8	12.1	12.4	12.8	11.4	7.4	4.1	5.6	7.2	8.7	9.8
Upper Falls	63.4	5.9	5.6	6.8	7.0	7.3	6.5	4.2	2.3	3.2	4.1	4.9	5.6
TOTAL	*1,113.0*	*104.1*	*97.5*	*120.1*	*123.6*	*127.6*	*113.8*	*73.8*	*41.0*	*56.1*	*71.5*	*86.3*	*97.6*
Mid-Columbia- Contracts	602.2	69.3	51.1	45.8	55.9	65.8	71.3	67.5	48.8	37.3	43.7	21.1	24.7
Priest Rapids	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rocky Reach	178.6	19.3	13.3	12.0	15.8	16.7	19.1	18.7	16.0	10.1	11.7	12.0	14.0
Wanapum	288.3	35.9	27.6	24.6	29.1	35.1	37.9	34.8	20.6	19.5	23.1	0.0	0.0
Wells	135.3	14.1	10.2	9.1	11.0	14.0	14.3	13.9	12.2	7.7	8.9	9.1	10.7
TOTAL	*602.2*	*69.3*	*51.1*	*45.8*	*55.9*	*65.8*	*71.3*	*67.5*	*48.8*	*37.3*	*43.7*	*21.1*	*24.7*
\vista Hydro Adjustment	232.3	18.3	17.3	17.3	22.3	33.5	33.5	24.1	13.8	10.9	11.3	12.3	17.6
TOTAL	*4,785.7*	*373.5*	*356.7*	*357.4*	*464.3*	*705.9*	*703.9*	*501.0*	*285.4*	*224.1*	*230.4*	*238.2*	*344.9*
Thermals													
Boulder Park	6.5	0.2	0.2	0.1	0.5	0.5	0.2	1.2	1.8	1.4	0.2	0.1	0.1
Colstrip	1,729.7	155.5	142.9	152.2	126.0	105.8	115.9	154.7	158.1	152.9	156.9	153.1	155.6
Coyote Springs 2	1,298.5	77.2	88.7	84.5	67.3	46.9	51.2	120.2	166.2	159.9	153.9	159.2	123.2
Kettle Falls	333.5	32.1	31.1	34.0	32.3	1.1	0.0	31.8	34.8	33.1	35.0	33.9	34.5
Kettle Falls CT	5.0	0.1	0.1	0.1	0.3	0.3	0.2	0.9	1.3	1.1	0.3	0.2	0.1
Northeast	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rathdrum	15.7	0.0	0.0	0.0	0.1	0.2	0.1	6.6	7.7	0.5	0.5	0.0	0.0
TOTAL	*3,388.9*	*265.2*	*263.2*	*271.0*	*226.4*	*154.9*	*167.6*	*315.3*	*369.9*	*348.8*	*346.6*	*346.6*	*313.5*
RESOURCE TOTAL	*7,942.2*	*620.4*	*602.5*	*611.1*	*668.5*	*827.3*	*837.9*	*792.2*	*641.5*	*561.9*	*565.7*	*572.5*	*640.8*
Contracts													
Black Creek	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0
DOPD	33.6	1.9	1.8	2.6	3.8	4.9	5.1	3.9	3.0	1.6	1.9	1.6	1.6
Market Contract 1	219.0	18.6	16.8	18.6	18.0	18.6	18.0	18.6	18.6	18.0	18.6	18.0	18.6
Can Ent Return	(35.9)	(3.1)	(2.8)	(3.0)	(3.0)	(3.0)	(3.0)	(3.1)	(3.0)	(3.0)	(3.1)	(2.9)	(3.1)
Grant County	155.6	16.0	12.0	10.0	8.9	6.7	9.4	10.7	10.4	8.9	10.3	23.7	28.5
Clark Fork LLC	1.4	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.1	0.1
Market Contract 2	657.0	55.8	50.4	55.8	54.0	55.8	54.0	55.8	55.8	54.0	55.8	54.0	55.8
Grant Displacement	194.1	13.0	11.8	13.1	18.8	23.7	22.8	20.5	14.6	13.7	13.9	13.9	14.3
Stimson Lumber	37.2	3.2	3.0	3.4	3.1	2.9	2.8	3.1	3.3	3.2	3.1	3.2	2.9
Jim Ford Creek	3.7	0.5	0.6	0.8	0.7	0.4	0.2	0.0	0.0	0.0	0.0	0.2	0.4
John Day Creek	2.0	0.1	0.0	0.1	0.1	0.4	0.4	0.3	0.2	0.1	0.1	0.1	0.1
Meyers Falls	7.8	0.7	0.8	0.9	0.9	1.0	0.8	0.5	0.2	0.3	0.4	0.6	0.6
Nichols Pumping	(67.9)	(5.8)	(5.2)	(5.8)	(5.6)	(5.8)	(5.6)	(5.8)	(5.8)	(5.6)	(5.8)	(5.6)	(5.8)
PGE CapExch	1.8	(0.3)	0.0	0.9	(0.3)	0.9	0.0	(0.6)	0.6	(0.3)	0.3	1.2	(0.6)
Phillips Ranch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Potlatch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Contract	69.3	6.2	4.6	6.6	5.8	6.1	6.9	6.1	6.2	5.6	6.0	6.4	2.7
Load Following Contracts	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sheep Creek	7.3	0.4	0.5	0.9	1.1	1.2	1.1	0.7	0.2	0.2	0.2	0.4	0.4
Upriver	52.2	5.6	6.3	7.3	7.6	7.7	5.8	1.9	(1.6)	0.6	2.3	3.1	5.6
WNP-3	368.7	76.1	68.8	37.6	36.4	0.0	0.0	0.0	0.0	0.0	0.0	73.7	76.1
ST Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SMUD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thompson River Co-Gen	92.2	8.4	7.7	8.4	7.0	6.9	5.4	8.3	8.5	8.2	7.6	7.4	8.5
TOTAL	*1,803.0*	*197.5*	*177.1*	*158.5*	*157.7*	*128.6*	*124.4*	*121.0*	*111.4*	*105.6*	*115.6*	*198.9*	*206.7*
Market Transactions													
Market Purchases	744.7	137.8	61.2	67.9	19.7	4.1	5.3	25.9	61.6	75.8	107.0	82.6	95.9
Market Sales	(1,426.5)	(37.6)	(57.5)	(81.8)	(179.0)	(300.3)	(300.0)	(174.9)	(69.0)	(62.9)	(49.8)	(66.3)	(47.3)
TOTAL	*(681.7)*	*100.2*	*3.7*	*(13.9)*	*(159.4)*	*(296.2)*	*(294.7)*	*(149.0)*	*(7.5)*	*12.9*	*57.2*	*16.3*	*48.6*
SYSTEM LOAD	*9,295.8*	*936.4*	*800.7*	*773.0*	*689.1*	*693.2*	*701.2*	*788.3*	*759.2*	*691.4*	*749.8*	*800.0*	*913.7*

Exhibit 5

AURORA$_{XMP}$ Summary Output—Project Generation (aMW)

	Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hydro Projects													
Clark Fork	324.0	244.4	283.9	234.3	364.6	643.8	674.0	451.1	244.3	166.3	139.6	164.7	275.5
Cabinet Gorge	104.1	78.6	91.2	75.3	117.2	206.9	216.7	145.0	78.5	53.4	44.9	52.9	88.6
Noxon Rapids	219.8	165.8	192.6	159.0	247.4	436.8	457.3	306.1	165.8	112.8	94.7	111.7	186.9
TOTAL (aMW)	*324.0*	*244.4*	*283.9*	*234.3*	*364.6*	*643.8*	*674.0*	*451.1*	*244.3*	*166.3*	*139.6*	*164.7*	*275.5*
Spokane River	127.1	139.9	145.1	161.4	171.7	171.5	158.0	99.2	55.1	78.0	96.1	119.8	131.2
Little Falls	25.5	28.1	29.2	32.4	34.5	34.5	31.8	19.9	11.1	15.7	19.3	24.1	26.4
Long Lake	50.9	56.0	58.1	64.6	68.7	68.7	63.2	39.7	22.1	31.2	38.5	48.0	52.5
Monroe Street	10.5	11.6	12.0	13.4	14.2	14.2	13.1	8.2	4.6	6.5	8.0	9.9	10.9
Nine Mile	20.1	22.2	23.0	25.6	27.2	27.2	25.1	15.7	8.7	12.4	15.2	19.0	20.8
Post Falls	12.8	14.1	14.6	16.2	17.3	17.2	15.9	10.0	5.5	7.8	9.7	12.0	13.2
Upper Falls	7.2	8.0	8.3	9.2	9.8	9.8	9.0	5.6	3.1	4.4	5.5	6.8	7.5
TOTAL (aMW)	*127.1*	*139.9*	*145.1*	*161.4*	*171.7*	*171.5*	*158.0*	*99.2*	*55.1*	*78.0*	*96.1*	*119.8*	*131.2*
Mid-Columbia- Contracts	68.7	93.1	76.0	61.5	77.6	88.4	99.1	90.7	65.6	51.8	58.7	29.3	33.2
Priest Rapids	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rocky Reach	20.4	25.9	19.8	16.1	21.9	22.5	26.6	25.2	21.5	14.0	15.7	16.6	18.8
Wanapum	32.9	48.3	41.1	33.1	40.4	47.2	52.7	46.8	27.7	27.1	31.0	0.0	0.0
Wells	15.4	18.9	15.2	12.3	15.3	18.8	19.8	18.7	16.4	10.7	12.0	12.7	14.4
TOTAL (aMW)	*68.7*	*93.1*	*76.0*	*61.5*	*77.6*	*88.4*	*99.1*	*90.7*	*65.6*	*51.8*	*58.7*	*29.3*	*33.2*
Avista Hydro Adjustment	26.5	24.6	25.8	23.2	30.9	45.0	46.6	32.4	18.6	15.2	15.2	17.1	23.6
TOTAL	*546.3*	*502.1*	*530.7*	*480.4*	*644.8*	*948.7*	*977.7*	*673.4*	*383.6*	*311.2*	*309.6*	*330.9*	*463.6*
Thermals													
Boulder Park	0.7	0.2	0.4	0.1	0.7	0.7	0.3	1.7	2.4	1.9	0.2	0.1	0.1
Colstrip	197.5	209.0	212.6	204.6	175.0	142.2	161.0	207.9	212.5	212.4	210.9	212.6	209.2
Coyote Springs 2	148.2	103.8	132.0	113.6	93.5	63.1	71.1	161.5	223.4	222.1	206.8	221.2	165.5
Kettle Falls	38.1	43.2	46.4	45.7	44.8	1.5	0.0	42.7	46.7	46.0	47.0	47.1	46.3
Kettle Falls CT	0.6	0.2	0.2	0.2	0.4	0.4	0.2	1.2	1.7	1.5	0.3	0.3	0.2
Northeast	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rathdrum	1.8	0.0	0.0	0.0	0.1	0.3	0.1	8.9	10.3	0.6	0.7	0.1	0.0
TOTAL	*386.9*	*356.4*	*391.6*	*364.2*	*314.5*	*208.2*	*232.7*	*423.8*	*497.1*	*484.5*	*465.9*	*481.3*	*421.3*
RESOURCE TOTAL	*906.6*	*833.8*	*896.6*	*821.4*	*928.4*	*1,111.9*	*1,163.8*	*1,064.8*	*862.2*	*780.5*	*760.3*	*795.1*	*861.3*
Contracts													
Black Creek	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	0.0	0.0
DOPD	3.8	2.6	2.6	3.5	5.3	6.6	7.1	5.2	4.1	2.2	2.5	2.2	2.1
Market Contract 1	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Can Ent Return	(4.1)	(4.2)	(4.1)	(4.0)	(4.1)	(4.0)	(4.1)	(4.2)	(4.0)	(4.1)	(4.2)	(4.0)	(4.2)
Grant County	17.8	21.6	17.9	13.5	12.4	9.0	13.1	14.4	13.9	12.4	13.9	32.9	38.3
Clark Fork LLC	0.2	0.1	0.2	0.1	0.3	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1
Market Contract 2	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Grant Displacement	22.2	17.5	17.5	17.6	26.2	31.8	31.6	27.6	19.7	19.0	18.7	19.3	19.2
Stimson Lumber	4.2	4.3	4.5	4.6	4.3	3.9	3.9	4.1	4.4	4.5	4.1	4.4	3.9
Jim Ford Creek	0.4	0.7	0.8	1.1	1.0	0.5	0.2	0.0	0.0	0.0	0.0	0.2	0.5
John Day Creek	0.2	0.1	0.0	0.1	0.1	0.5	0.6	0.4	0.2	0.2	0.2	0.2	0.1
Meyers Falls	0.9	1.0	1.2	1.3	1.3	1.3	1.2	0.6	0.3	0.4	0.6	0.9	0.8
Nichols Pumping	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)
PGE CapExch	0.2	(0.4)	0.0	1.2	(0.4)	1.2	0.0	(0.8)	0.8	(0.4)	0.4	1.7	(0.8)
Phillips Ranch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Potlatch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Contract	7.9	8.3	6.9	8.9	8.1	8.2	9.6	8.1	8.4	7.8	8.1	8.9	3.7
Load Following Contracts	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sheep Creek	0.8	0.5	0.7	1.2	1.6	1.6	1.6	1.0	0.3	0.2	0.3	0.5	0.5
Upriver	6.0	7.5	9.4	9.8	10.6	10.4	8.0	2.5	(2.1)	0.9	3.1	4.2	7.5
WNP-3	42.1	102.3	102.3	50.5	50.5	0.0	0.0	0.0	0.0	0.0	0.0	102.3	102.3
ST Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SMUD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thompson River Co-Gen	10.5	11.3	11.4	11.3	9.7	9.3	7.5	11.2	11.4	11.4	10.3	10.3	11.4
TOTAL	*205.8*	*265.4*	*263.6*	*213.0*	*219.0*	*172.9*	*172.8*	*162.7*	*149.7*	*146.7*	*155.4*	*276.2*	*277.9*
Market Transactions													
Market Purchases	85.0	185.2	91.0	91.2	27.3	5.6	7.4	34.8	82.7	105.3	143.8	114.8	128.9
Market Sales	(162.8)	(50.5)	(85.5)	(110.0)	(248.7)	(403.7)	(416.6)	(235.1)	(92.8)	(87.4)	(66.9)	(92.1)	(63.5)
TOTAL	*(77.8)*	*134.7*	*5.5*	*(18.7)*	*(221.3)*	*(398.1)*	*(409.3)*	*(200.3)*	*(10.0)*	*17.9*	*76.9*	*22.7*	*65.4*
System Load	*1,061.2*	*1,258.5*	*1,191.5*	*1,038.9*	*957.0*	*931.7*	*973.9*	*1,059.6*	*1,020.4*	*960.2*	*1,007.8*	*1,111.1*	*1,228.1*

Exhibit 5
AURORA$_{XMP}$ Summary Output—Project Costs ($000s)

	Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hydro Projects													
Clark Fork	0	0	0	0	0	0	0	0	0	0	0	0	0
Cabinet Gorge	0	0	0	0	0	0	0	0	0	0	0	0	0
Noxon Rapids	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Spokane River	0	0	0	0	0	0	0	0	0	0	0	0	0
Little Falls	0	0	0	0	0	0	0	0	0	0	0	0	0
Long Lake	0	0	0	0	0	0	0	0	0	0	0	0	0
Monroe Street	0	0	0	0	0	0	0	0	0	0	0	0	0
Nine Mile	0	0	0	0	0	0	0	0	0	0	0	0	0
Post Falls	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Falls	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Mid-Columbia- Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
Priest Rapids	0	0	0	0	0	0	0	0	0	0	0	0	0
Rocky Reach	0	0	0	0	0	0	0	0	0	0	0	0	0
Wanapum	0	0	0	0	0	0	0	0	0	0	0	0	0
Wells	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Avista Hydro Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Thermals													
Boulder Park	468	14	20	7	38	36	13	88	129	98	12	7	7
Colstrip	19,388	1,742	1,600	1,705	1,411	1,189	1,307	1,734	1,771	1,713	1,757	1,714	1,743
Coyote Springs 2	70,663	4,576	5,248	4,875	3,455	2,398	2,647	6,297	8,722	8,400	8,112	8,788	7,146
Kettle Falls	11,811	1,143	1,102	1,202	1,145	41	0	1,130	1,228	1,171	1,234	1,196	1,219
Kettle Falls CT	354	9	11	9	20	21	12	60	90	76	18	18	10
Northeast	0	0	0	0	0	0	0	0	0	0	0	0	0
Rathdrum	1,373	0	3	0	5	19	7	578	676	41	40	4	0
TOTAL	***104,056***	***7,485***	***7,984***	***7,798***	***6,074***	***3,705***	***3,986***	***9,887***	***12,617***	***11,498***	***11,173***	***11,727***	***10,125***
RESOURCE TOTAL	***104,056***	***7,485***	***7,984***	***7,798***	***6,074***	***3,705***	***3,986***	***9,887***	***12,617***	***11,498***	***11,173***	***11,727***	***10,125***
Contracts													
Black Creek	197	0	0	0	0	0	0	0	0	0	197	0	0
DOPD	737	42	38	57	83	108	111	85	66	35	42	35	35
Market Contract 1	7,556	642	580	642	621	642	621	642	642	621	642	621	642
Can Ent Return	0	0	0	0	0	0	0	0	0	0	0	0	0
Grant County	8,473	818	663	525	408	274	333	547	612	491	552	1,498	1,751
Clark Fork LLC	117	9	10	9	16	17	17	11	6	4	3	6	9
Market Contract 2	20,192	1,715	1,549	1,715	1,660	1,715	1,660	1,715	1,715	1,660	1,715	1,660	1,715
Grant Displacement	5,824	389	354	394	565	711	683	616	439	410	418	416	429
Stimson Lumber	2,079	194	182	159	145	136	131	186	196	195	185	193	177
Jim Ford Creek	234	44	49	37	32	18	7	0	0	0	1	15	32
John Day Creek	82	4	2	3	3	12	14	11	7	6	5	8	6
Meyers Falls	375	35	38	45	44	46	40	22	10	13	21	30	30
Nichols Pumping	(3,394)	(291)	(284)	(296)	(253)	(237)	(201)	(291)	(327)	(299)	(296)	(307)	(312)
PGE CapExch	0	0	0	0	0	0	0	0	0	0	0	0	0
Phillips Ranch	1	0	0	0	0	0	1	0	0	0	0	0	0
Potlatch	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind Contract	2,743	245	182	262	230	242	275	240	247	222	238	253	108
Load Following Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
Sheep Creek	426	27	34	51	54	51	45	43	23	19	22	30	29
Upriver	2,017	246	277	249	262	264	197	83	(68)	28	101	134	245
WNP-3	13,333	2,753	2,487	1,359	1,316	0	0	0	0	0	0	2,664	2,753
ST Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
SMUD	(8,561)	(737)	(574)	(652)	(658)	(836)	(987)	(828)	(688)	(666)	(661)	(609)	(664)
Thompson River Co-Gen	5,119	466	425	467	387	382	301	461	470	455	424	410	471
TOTAL	***57,553***	***6,602***	***6,012***	***5,025***	***4,915***	***3,545***	***3,247***	***3,543***	***3,350***	***3,194***	***3,610***	***7,056***	***7,456***
Market Transactions													
Market Purchases	51,397	8,817	4,175	4,464	1,274	296	334	2,134	5,110	5,586	7,105	5,625	6,476
Market Sales	(65,050)	(2,046)	(3,382)	(4,426)	(8,207)	(12,494)	(10,414)	(8,431)	(3,643)	(3,056)	(2,496)	(3,771)	(2,684)
TOTAL	***(13,653)***	***6,772***	***793***	***38***	***(6,933)***	***(12,198)***	***(10,079)***	***(6,297)***	***1,467***	***2,530***	***4,609***	***1,854***	***3,792***
Fuel and Market Only	**90,403**	**14,256**	**8,777**	**7,835**	**(859)**	**(8,493)**	**(6,093)**	**3,590**	**14,084**	**14,027**	**15,782**	**13,581**	**13,916**
Fuel Transport Adjustment	***(1,748)***	***(123)***	***(140)***	***(135)***	***(85)***	***(60)***	***(65)***	***(151)***	***(207)***	***(198)***	***(189)***	***(226)***	***(170)***
Startup Fuel Adustment	***482***	***52***	***36***	***41***	***37***	***23***	***39***	***75***	***52***	***23***	***46***	***37***	***21***
Total	***89,137***	***14,185***	***8,673***	***7,740***	***(906)***	***(8,530)***	***(6,119)***	***3,514***	***13,929***	***13,852***	***15,639***	***13,392***	***13,768***