

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-07 _____

DIRECT TESTIMONY OF

CLINT G. KALICH

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

1
2 **Q. Please state your name, the name of your employer, and your business**
3 **address.**

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

6 **Q. In what capacity are you employed?**

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

9 **Q. Please state your educational background and professional experience.**

10 A. I graduated from Central Washington University in 1991 with a Bachelor of
11 Science Degree in Business Economics. Shortly after graduation, I accepted an analyst
12 position with Economic and Engineering Services, Inc. (now EES Consulting, Inc.), a
13 Northwest management-consulting firm located in Bellevue, Washington. While employed
14 by EES, I worked primarily for municipalities, public utility districts, and cooperatives in the
15 area of electric utility management. My specific areas of focus were economic analyses of
16 new resource development, rate case proceedings involving the Bonneville Power
17 Administration, integrated (least-cost) resource planning, and demand-side management
18 program development. In late 1995, I left Economic and Engineering Services, Inc. to join
19 Tacoma Power in Tacoma, Washington. I provided key analytical and policy support in the
20 areas of resource development, procurement, and optimization, hydroelectric operations and
21 re-licensing, unbundled power supply rate-making, contract negotiations, and system
22 operations. I helped develop, and ultimately managed, Tacoma Power's industrial market

1 access program serving one-quarter of the company's retail load. In mid-2000 I joined Avista
2 Utilities as a Senior Power Resource Analyst.

3 In 2001, I accepted my current position, assisting the Company in resource analysis,
4 dispatch modeling, resource procurement, integrated resource planning, and rate case
5 proceedings. Much of my career has involved resource dispatch modeling of the nature
6 described in this testimony.

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

8 A. My testimony will describe the Company's use of the AURORA dispatch
9 model, hereinafter referred to as the "Dispatch Model." I will explain the key assumptions
10 driving the Dispatch Model's market forecast of electricity prices. The discussion includes
11 the variables of natural gas, Western Electricity Coordination Council ("WECC") loads and
12 resources, and hydroelectric conditions. I will describe how the model dispatches our
13 resources and contracts in a manner that maximizes benefits to customers and tracks their
14 values for use in pro forma calculations. Finally, I will present the modeling results provided
15 to Company Witness Mr. Johnson for his power supply pro forma adjustment calculations.

16 Below is a table of contents for my testimony:

	<u>Description</u>	<u>Pages</u>
17	I. Introduction	1-2
18	II. The Dispatch Model	3-14
19	III. Rate Period Loads	15-20
20	IV. Results	20
21		
22		

1 **Q. Are you sponsoring any exhibits in this proceeding?**

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

5 **II. THE DISPATCH MODEL**

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

8 A. The Company uses EPIS, Inc.’s AURORA_{XMP} system dispatch model
 9 (“Dispatch Model”) for determining power supply costs. The model optimizes dispatch of
 10 Company-owned resources and contracts in each hour of the pro forma year. The pro forma
 11 period is January 1, 2008 through December 31, 2008. It reflects true system operations by
 12 evaluating future resource decisions on an hourly basis.

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

15 A. The Company is using a February 6, 2007 version of AURORA_{XMP}
 16 (v.8.4.1022), and the latest available database version (released in December 2006).

17 **Q. Please briefly describe the Dispatch Model.**

18 A. The AURORA_{XMP} Electric Market Model was developed by EPIS, Inc. of
 19 West Linn, Oregon. AURORA_{XMP} is a fundamentals-based tool that contains demand and
 20 resource data for the entire WECC, and employs multi-area, transmission-constrained
 21 dispatch logic to simulate real market conditions. Its true economic dispatch captures the
 22 dynamics and economics of electricity markets—both short-term (hourly, daily, monthly) and

1 long-term. On an hourly basis the Dispatch Model develops an available resource stack,
2 sorting resources from lowest to highest cost. It then compares this resource stack with load
3 obligations in the same hour to arrive at the least-cost market-clearing price for the hour.
4 Once resources are dispatched and market prices are determined, the Dispatch Model singles
5 out Avista resources and loads and values them against the marketplace.

6 **Q. What experience does the Company have using AURORA_{XMP}?**

7 A. The Company purchased a license to use AURORA_{XMP} in April 2002.
8 AURORA_{XMP} has been used for numerous studies, including the Company's 2003 and 2005
9 Integrated Resource Plans ("IRPs"), our 2004 general rate case filing in the State of Idaho,
10 and our 2005 general rate case filing before this Commission. AURORA_{XMP} also is being
11 used in the Company's 2007 IRP.

12 **Q. Who else uses AURORA_{XMP}?**

13 A. AURORA_{XMP} is used all across North America. In the Northwest specifically,
14 AURORA_{XMP} is used by the Bonneville Power Administration, the Northwest Power and
15 Conservation Council, Puget Sound Energy, Idaho Power, Seattle City Light, and Tacoma
16 Power, among others.

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

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

1 The Company owns a number of resources, including hydroelectric plants and natural
2 gas-fired peaking units, which serve customer loads during more valuable on-peak hours. By
3 optimizing resource operation on an hourly basis, the Dispatch Model is able to appropriately
4 value the capabilities of these assets. For example, actual 2005 on-peak prices were 18.3%
5 higher than off-peak prices. In 2006 the difference was 28.0%. By comparison, Dispatch
6 Model on-peak prices for the pro forma period averaged 26.6% higher than off-peak prices.
7 In summary, the Dispatch Model appropriately values the energy from Avista's resources
8 during on-peak periods in a manner similar to that recently experienced in the Northwest
9 region.

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

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

1 into the market is determined based on the electric market-clearing price for the specified
2 hour and the amount of energy necessary to balance loads and resources.

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

5 A. The Dispatch Model calculates electricity prices for the entire WECC,
6 separated into various geographical areas such as the Northwest, and Northern and Southern
7 California. The load in each area is compared to available resources, including resources
8 available from other areas that are linked by transmission corridors, to determine the
9 electricity price in each hour. Ultimately, the market price for an hour is set based on the last
10 resource in the stack to be dispatched. This resource is referred to as the “marginal resource.”
11 Given the prominence of natural gas-fired resources on the margin, this fuel is a key variable
12 in the determination of wholesale electricity prices.

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

14 A. The model begins by lowering hourly regional loads by forecasted wind
15 energy and must-run generators. It then “peak shaves” remaining loads using system hydro
16 resources. When peak shaving, the Dispatch Model determines which hours contain the
17 highest loads and allocates to them as much hydroelectric energy as possible.

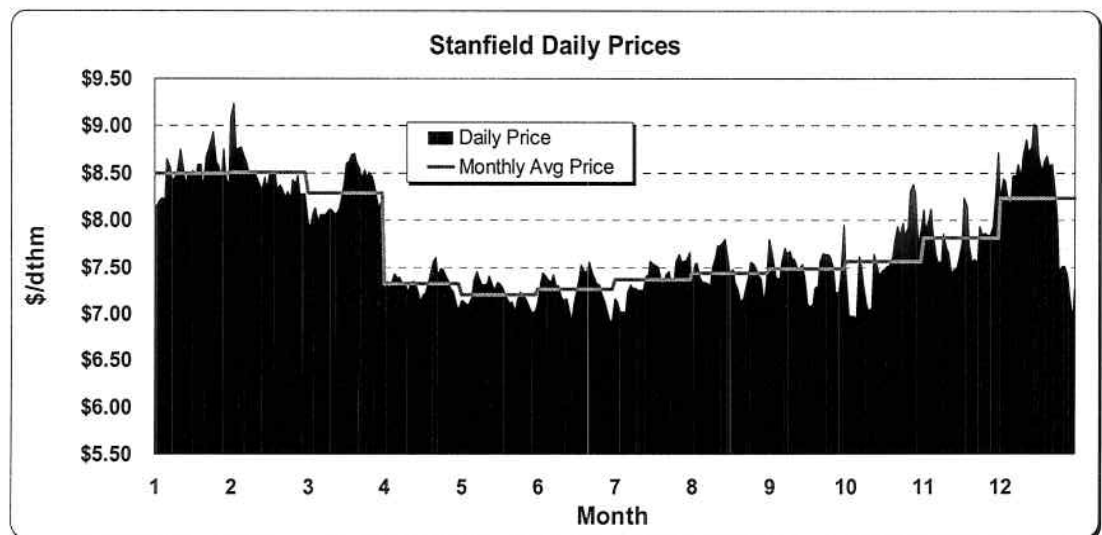
18 **Q. Has the Company made any modifications to the database for this case?**

19 A. Yes. In addition to updating assumptions around the Company’s portfolio of
20 resources the Company has modified pro forma period natural gas prices, northwest hydro
21 data, and start-up and minimum up and minimum down times for all Western Interconnect
22 combined-cycle gas-fired combustion turbines (CCCTs).

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

2 A. Natural gas prices for this filing are based on a 3-month average of 2008
3 monthly forwards from November 23, 2006 to February 22, 2007. This method is consistent
4 with what was previously ordered by the commission in Puget Sound Energy order No. UE-
5 040641 and in our last proceeding (Order No. UE-050482). Prices are fitted to a daily shape
6 based on daily spot market prices at AECO between January 2003 and December 2006
7 (excluding February and March 2003 and October 2006 where daily price volatility was very
8 high). The daily and monthly average gas price shapes at Stanfield is shown in Chart No. 1.
9 Other basins retain the same daily shape.

10 **Chart No. 1 – Daily Natural Gas Price Shape**



11
12 Natural gas prices were modified to ensure prices across the Western Interconnect
13 were consistent with changes made to the Northwest. Annual average natural gas prices are
14 presented below in Table No 1.

15

16

1 **Table No. 1 – Pro Forma Natural Gas Prices**

Basin	Price (\$/dth)	Basin	Price (\$/dth)
AECO	7.39	Stanfield	7.78
Malin	7.83	Sumas	7.76
Spokane	8.11	Henry Hub	8.22
Rockies	6.79	Topock	7.36

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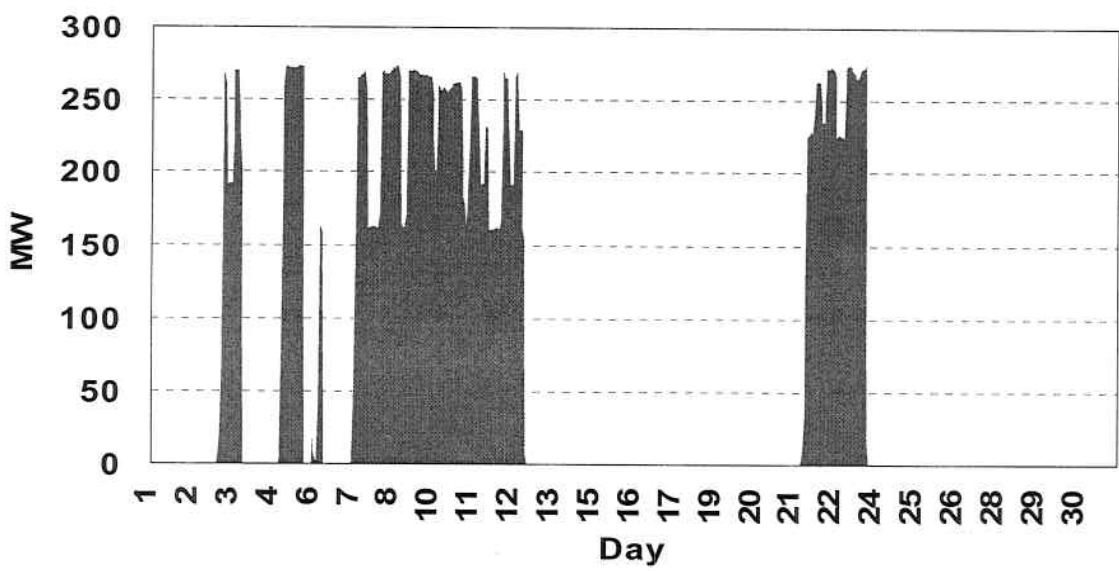
3 **Q. What hydro record is the Company using in this filing?**

4 A. The Company bases this case on the 50-year hydrological record beginning in
5 1929. This period is the same as adopted in the Company's 2005 general rate case (See
6 Commission Order No. UE-050482). Data are sourced from the Northwest Power Pool's
7 (NWPP) 2004-05 Headwater Benefits Study.

8 **Q. What changes did the Company make to Western Interconnect
9 combined-cycle gas-fired turbines (CCCTs)?**

10 A. When reviewing the operating profiles of CCCT plants, it became apparent
11 that the model was not properly dispatching these resources. CCCT plants are very important
12 to forecasting electricity prices; they set the hourly marginal electricity prices in many hours.
13 CCCT plants, in the unmodified AURORA_{XMP} database, cycled on average every two days
14 when in fact neither operational and cost limitations nor history support this generation
15 profile. This concern is described in Chart Nos. 2 through 4. Chart No. 2 provides the actual
16 dispatch profile of Coyote Springs 2 during January 2006.

1 Chart No. 2 – CS2 Dispatch (January 2006 Actual)

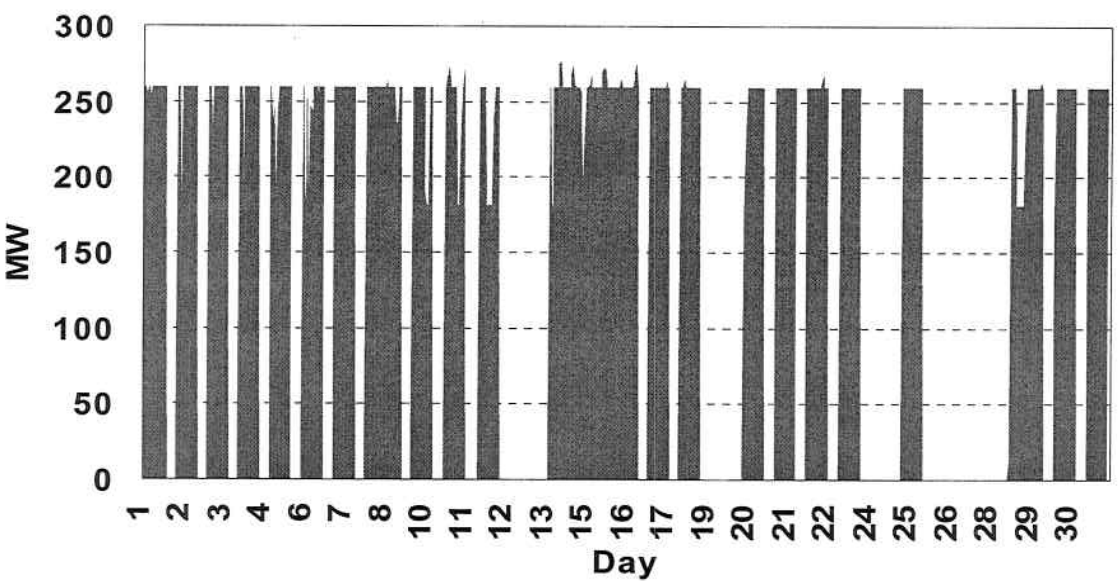


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3 Chart 3 shows Coyote Springs 2 during the January 2008 pro forma period prior to

4 modifying database assumptions for CCCT plants.

5 Chart No. 3 – CS2 Dispatch (January 2008 Pro Forma "Out of the Box Logic")



6

7 The AURORA_{XMP} database starts up and shuts down Coyote Springs 2 nearly every

8 day. This operational pattern is consistent throughout the year and is not realistic. To resolve

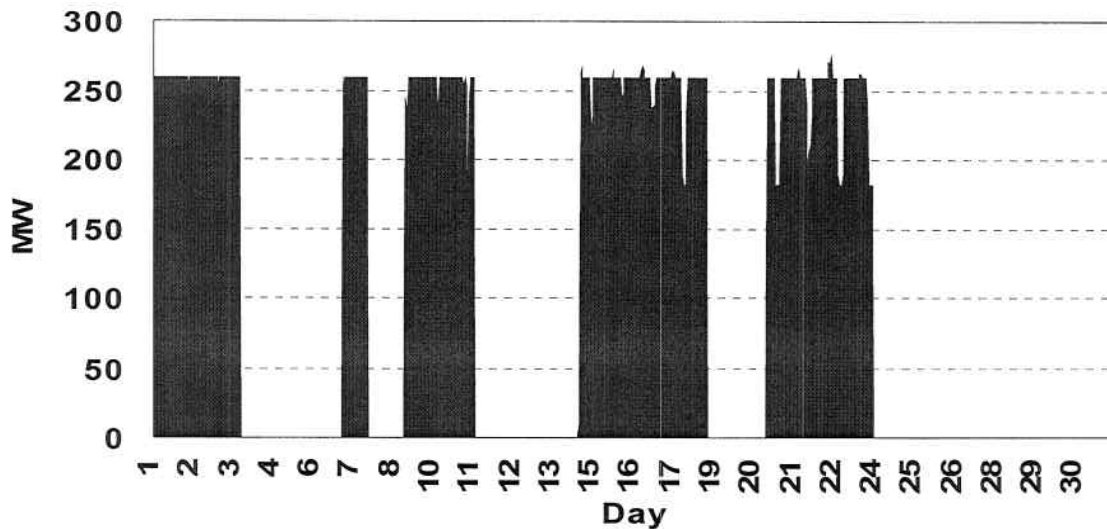
1 this modeling problem, the Company modified the start-up cost and minimum up and
2 minimum down times to achieve a more reasonable CCCT dispatch profile for the Western
3 Interconnect and is presently working with EPIS, the developer of AURORA_{XMP}, to address
4 our concerns with CCCT plant dispatch.

5 Start-up costs were identified as a key driver to the incorrect dispatch behavior of
6 CCCT plants. In most cases, CCCT plant start-up costs in the AURORA_{XMP} database were
7 between \$11 and \$15 per MW. A \$15 per MW start-up cost on a 250 MW CCCT plant
8 equates to only \$3,750. Based on our experience, this cost is too low by orders of magnitude.
9 The Company changed start-up costs for all CCCT plants in the AURORA_{XMP} database to
10 \$85 per MW per start. This number was derived by using estimates from Coyote Springs 2,
11 which included 1,808 decatherms of fuel per cold start, \$10,000 of estimated O&M costs, and
12 \$7.75 as the average gas price. $(1,808 \times \$7.75 = \$14,012 + \$10,000 = \$24,012 / 287 \text{ MW} =$
13 $\$83.67 \text{ per MW, rounded up to an } \$85 \text{ estimate.})$

14 The second modification made by the Company was to change the minimum up and
15 minimum down times from 16 hours and 8 hours respectively, to 20 hours.

16 These two changes, when taken together, provide for a much more reasonable
17 dispatch of CCCT plants in the Western Interconnect, as shown in Chart No. 4.

1 Chart No. 4 – CS2 Dispatch (January 2008 Pro Forma “Filed Method”)



2

3 Q. How does the Dispatch Model operate Company-controlled hydroelectric
4 generation resources?

5 A. The Dispatch Model treats all hydroelectric generation plants within a load
6 area as a single large plant. The Company’s hydroelectric plants are on average, however,
7 more flexible than the average plant used in each load area. For example Noxon Rapids is
8 able to shift a substantially higher percentage of its electricity generation into higher-value
9 on-peak hours relative to other plants in the region. To account for this additional flexibility,
10 the Company algebraically extracts its plants from the region and develops individual hydro
11 operations logic for them. Company-controlled hydroelectric resources are separated into
12 three river systems: the Mid-Columbia, the Spokane River, and the Clark Fork River
13 projects. This separation ensures that the flexibility inherent in these resources is credited to
14 customers in the pro forma exercise.

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

3 A. Over the pro forma period the Dispatch Model dispatches 67.6% of the
4 Company's hydro generation during on-peak hours. Since on-peak hours represent only 57%
5 of the year, this demonstrates a substantial shift of hydro resources to the more expensive on-
6 peak hours. This is nearly identical to the 5-year average of on-peak hydroelectric generation
7 through 2006: 67.7%.

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

10 A. Natural gas prices are a function of average commodity cost, transportation,
11 and applicable taxes. Consistent with our last general rate case filing, natural gas prices were
12 set using an average of witnessed forward prices for calendar year 2008 during the three-
13 month period ending February 22, 2007. The average price for the year equals \$7.78 per
14 decatherm at Rathdrum and CS2, and \$8.11 per decatherm for Northeast, Boulder Park, and
15 the Kettle Falls CT. For comparison, the average Henry Hub price for the period is \$8.22 per
16 decatherm. See Table 2 on page 14 of my testimony for a listing of monthly natural gas
17 prices for the Company's gas-fired plants.

18 **Q. The Company used bidding factors in its last general rate case filing to**
19 **align modeling results with then-current forward market conditions. Is the Company**
20 **using bidding factors in this filing?**

21 A. No, the Company is not using bidding factors for this case. In the 2005 rate
22 case the Company found in pre-filing runs that AURORA_{XMP} was over-estimating forward

1 electricity prices when compared to then-forward electric prices. The Company used bidding
2 factors to align the AURORA_{XMP} forecast of Mid-Columbia electricity prices for 2006 with
3 forward market prices for that year. AURORA_{XMP}'s ability to forecast market prices is
4 highly dependent on the underlying database of resources, their assumptions, and forecasted
5 loads. At the time our last general case was prepared, the Company was concerned that the
6 latest database provided by EPIS with the AURORA_{XMP} model contained assumptions that
7 adversely affected its market forecast. Given the limited time available to modify the
8 database, bidding factors were found to provide an efficient means to correct the model's
9 behavior.

10 There was significant concern over the Company's use of bidding factors in the last
11 case. Therefore, the Company increased its efforts to address problems in the underlying
12 AURORA_{XMP} database for this filing. Our concerns were voiced to EPIS, the vendor of
13 AURORA_{XMP}. The latest database does a much better job of forecasting market prices than
14 the version used for the last general rate case.

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

17 A. Table No. 2 presents modeled natural gas and electricity prices in the Dispatch
18 Model.

1 **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-08	8.502	8.892	58.31	Jul-08	7.373	7.718	50.55
Feb-08	8.505	8.895	62.05	Aug-08	7.431	7.778	57.60
Mar-08	8.289	8.671	58.72	Sep-08	7.484	7.833	59.94
Apr-08	7.325	7.668	49.40	Oct-08	7.569	7.921	58.83
May-08	7.207	7.546	43.77	Nov-08	7.821	8.184	61.41
Jun-08	7.264	7.605	37.80	Dec-08	8.237	8.617	61.50
				Average	7.780	8.111	55.02

2

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

6 A. No, the NWPP study does not include the Cabinet Unit 4 upgrade. As was in
7 April of this year, and will not be included in our next data submittal to the NWPP. I expect
8 the upgrade to be reflected in the 2008 NWPP study.

9 **Q. How have you accounted for the Cabinet Unit 4 upgrade in the pro**
10 **forma?**

11 A. The Cabinet Unit 4 upgrade is expected to generate 1.1 average megawatts of
12 additional energy in an average water year. To account for this energy amount in the pro
13 forma, the unit size is increased from 59.4 MW to 69.4 MW. The Dispatch Model then
14 generates at the upgraded energy and capacity levels when it dispatches Cabinet Unit 4.

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

17 A. The Company increased the generation capability of each unit from 740 MW
18 to 768 MW. This change allows the Dispatch Model to correctly value the entirety of each

1 plant in the wholesale marketplace. Our resource portfolio tracked in the Dispatch Model
2 contains a 15% share of each unit. With the overall capacity of each resource increased, our
3 15% allocation increases proportionally and lowers the overall cost of our generation
4 portfolio.

5 III. RATE PERIOD LOADS

6 **Q. Company witness Mr. Norwood explains in his testimony that the**
7 **Company is modeling net power supply expenses based on 2008 rate period loads. Will**
8 **you please explain the source for this data?**

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

16 The rate period loads used in this case are taken from the Company's 2007 load
17 forecast completed in July 2006. The 2008 load value is 1,065 aMW. As this load is
18 generated using "normal weather," it eliminates the need for a weather-normalization
19 adjustment.

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

21 A. Yes. For the residential, small and large general service, pumping and street
22 light customers, the methodology is based on mathematical relationships between growth in

1 the economy of the service area and the energy used by customers. Very large general service
2 customer (e.g., hospitals, universities, manufacturers) forecasts rely on trends in these
3 segments combined with regular discussion with the individual customers regarding
4 expansion (or contraction) plans.

5 **Q. How does Avista acquire service area economic forecasts?**

6 A. Avista contracts with Global Insight, Inc., a national economic forecasting
7 consulting company also used by several agencies in the State of Washington (including the
8 Office of the Forecast Council), to provide county-level projections of job growth, population
9 growth and personal income growth. These are the primary drivers of electricity
10 consumption. Global Insights, Inc. also provides projections for interest rates, oil prices, the
11 consumer price index and other factors used to project customer growth and customer
12 consumption.

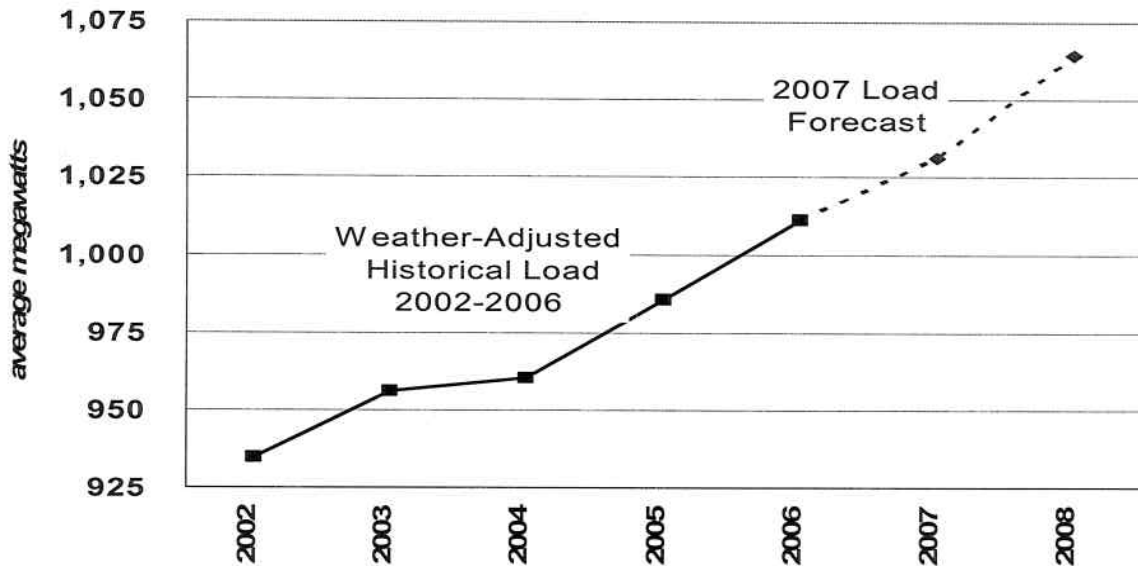
13 **Q. Does Avista include the impact of conservation and electricity prices**
14 **when projecting future electricity load?**

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

21 **Q. How do 2008 pro forma period loads compare with recent results?**

1 A. Chart No. 5 shows historical and forecast utility load changes. As the table
2 illustrates, our 2007 forecast of retail load follows a trend line consistent with recent history.

3 **Chart No. 5 – System Loads Absent Potlatch Cogeneration**



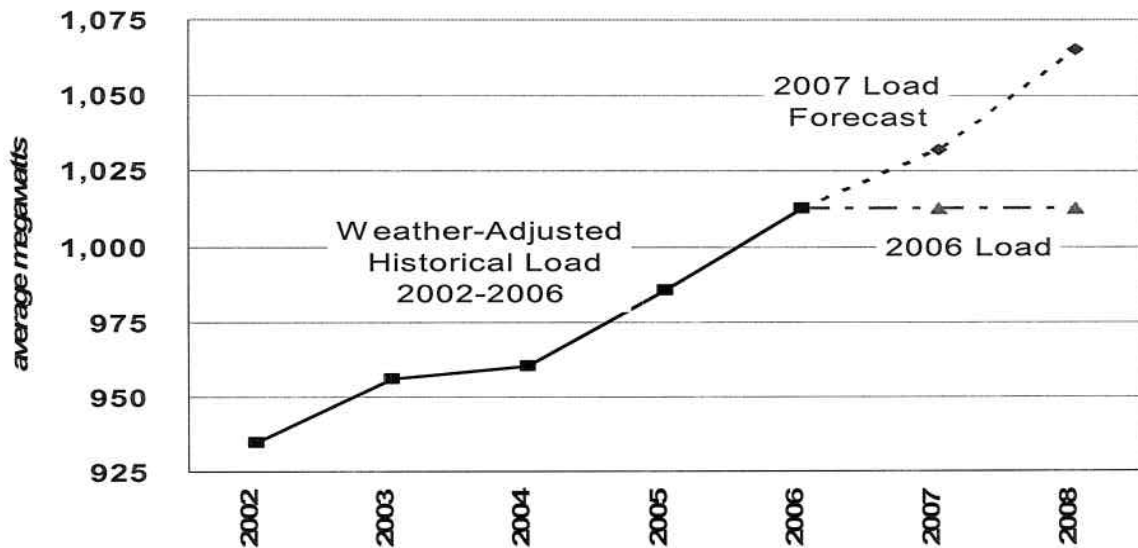
4
5 **Q. What is the significance of using the forecasted pro forma load estimate**
6 **for ratemaking purposes?**

7 A. Mr. Norwood explained in his testimony how the use of pro forma 2008 retail
8 loads, together with a “Production Property Adjustment,” provide an appropriate matching of
9 revenues and expenses during the period that new rates will be in effect (2008). The
10 Production Property Adjustment reduces pro forma fixed and variable production and
11 transmission costs to account for higher anticipated 2008 retail loads.

12 Chart No. 6 builds on information presented in Chart No. 5. It illustrates why 2006
13 load levels should not be used to set rates for calendar year 2008: using 2006 weather-
14 adjusted actual loads would assume the Company will experience no load growth for two
15 calendar years. This would be at odds with recent history and any reasonable load growth

1 assumption, especially given the robust economy in our Company's service area. Pro forma
2 load levels will be approximately 53 aMW above 2006 historical loads.

3 **Chart No. 6 –System Loads Absent Potlatch Cogeneration, with 2006 Load**



4
5 **Q. Does the difference between pro forma and actual loads get tracked**
6 **through the ERM?**

7 A. As explained more fully by Mr. Johnson, when actual 2008 loads differ from
8 the pro forma, the difference between the two values is tracked through the ERM, with
9 additional or reduced sales being adjusted through the Retail Revenue Credit.

10 The use of 2008 pro forma loads in this case, together with the production property
11 adjustment, provides a more accurate basis to project rates from.

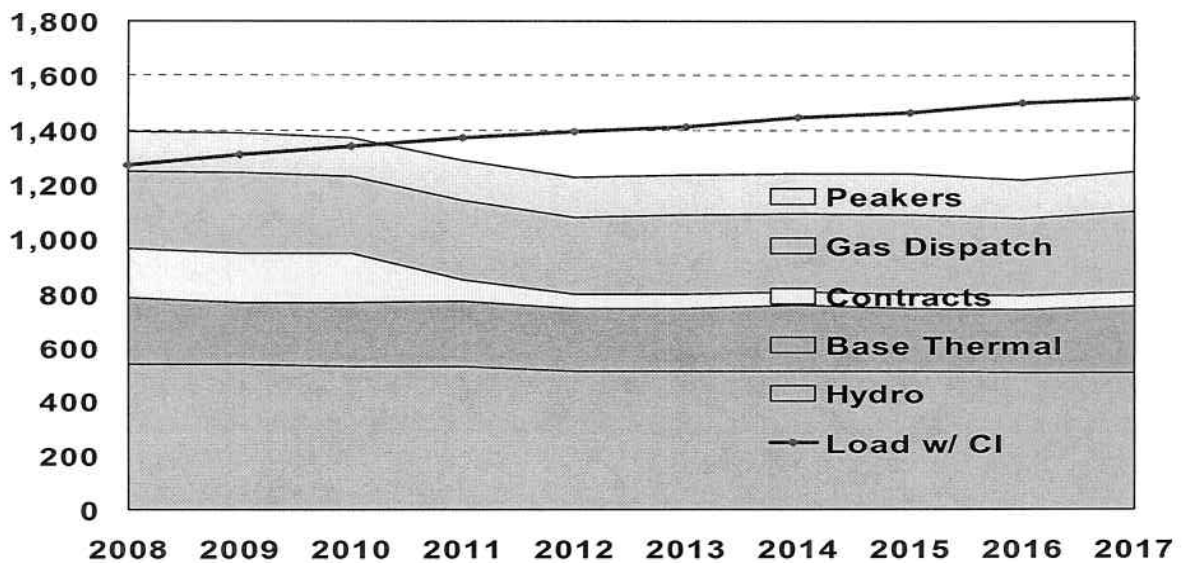
12 **Q. What is the Company's present loads and resources position?**

13 A. The Company's latest energy and capacity loads and resources tabulations
14 (L&Rs) are attached in Exhibit No. ___(CGK-2). As the L&Rs show, 2008 loads are
15 expected to equal 1,125 aMW. For this filing the figure is reduced by 60 aMW of self-

1 generation by the Potlatch Corporation, a large industrial customer load located in Idaho.
 2 This adjustment lowers the pro forma load to 1,065 aMW.

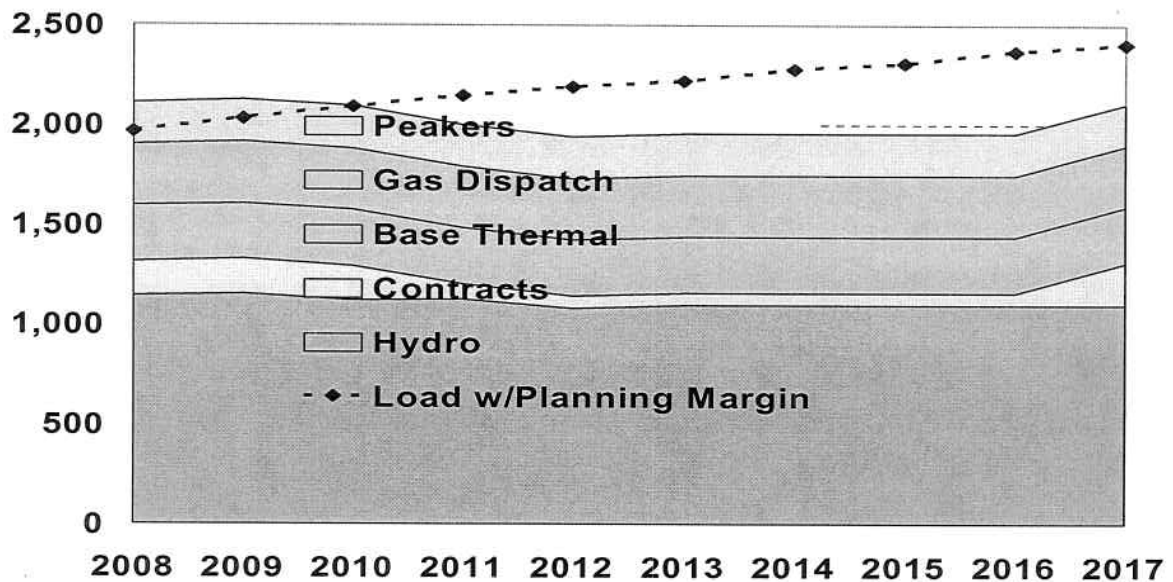
3 Chart No. 7 below details the Company’s energy and resources position from 2008
 4 through 2017. The chart excludes 60 aMW of Potlatch load, as well as its 60 aMW of
 5 PURPA generation.

6 **Chart No. 7 – Avista 2008-2017 Load and Resource Energy Position (aMW)**



7
 8 Chart No. 8 presents the Company’s capacity and resources position from 2008
 9 through 2017. As with Chart No. 7, a 60-MW reduction is applied both to load and contracts
 10 to reflect Potlatch.

1 **Chart No. 8 – Avista 2008-2017 Load and Resource Capacity Position (MW)**



2
3
4 **IV. RESULTS**

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

7 A. The Dispatch Model tracks the Company's portfolio during each hour of the
8 pro forma study. Fuel costs and generation for each resource are summarized by month.
9 Total market sales and purchases, and their revenues and costs, are also determined and
10 summarized by month. These values are contained in Exhibit No. ___(CGK-3) and were
11 provided to Mr. Johnson for use in his calculations. Mr. Johnson adds resource and contract
12 revenues and expenses not accounted for in the Dispatch Model (e.g., fixed costs) to
13 determine net power supply expense.

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

15 A. Yes, it does.