Exhibit No. ___(CGK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-10______

DIRECT TESTIMONY OF

CLINT G. 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 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 the Company and accepted my current position assisting 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, or "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 discuss why Hydro Biasing, as suggested in previous cases by some parties, leads to under-recovery of costs and is unnecessary because of recent modifications to the Energy Recovery Mechanism (ERM). 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. I will then present the modeling results provided to Company witness Mr. Johnson for his power supply pro forma adjustment calculations. Additionally, in support of Company witness Ms. Knox, I detail the Company's demand classification calculations.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring three exhibits marked Exhibit No. ___(CGK-2), Exhibit No. ___(CGK-3), and Confidential Exhibit No. ___(CGK-4C). Exhibit No. ___(CGK-2) provides a forecast of Company load and resource positions from 2011 through 2020. Exhibit No. ___(CGK-3) is the spreadsheet used to calculate the demand classification. Confidential Exhibit No. ___(CGK-4C) provides summary output from the Dispatch Model. All information contained in the exhibits was prepared by me or 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 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, 2011 through December 31, 2011. 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 $\text{AURORA}_{\text{XMP}}$ version 9.6.1033, and its associated database (North_American_DB_2009-02).

Q. Please briefly describe the Dispatch Model.

A. The Dispatch Model was developed by EPIS, Inc. of Sandpoint, Idaho. It 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—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 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 the Dispatch Model in April 2002. AURORA$_{XMP}$ has been used for numerous studies, including all of our integrated resource plans and rate filings after 2001. The tool is also used for various resource evaluations, market forecasting, and requests-for-proposal evaluations.

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

A. AURORA$_{XMP}$ is used all across North America and in Europe. 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, Snohomish County PUD, and Tacoma Power.

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 2008 and 2009 on-peak prices were 23 percent higher than off-peak prices. 2007 on-peak prices were 25 percent higher. Forward on-peak prices for 2011 were 27 percent higher than off-peak prices at the time this case was prepared. For comparison, Dispatch Model on-peak prices for the pro forma period average 28 percent 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 available resources to determine a net position. This 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?

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.

III. HYDRO MODELING ASSUMPTIONS

Q. How has the Company modeled hydroelectric generation for this case?

A. As in the past, Avista uses historical stream flow data from the Northwest Power Pool (NWPP) to determine hydroelectric generation for its Clark Fork and Spokane River systems. Certain adjustments to the NWPP data are necessary to yield a proper estimate of generation from the model. These adjustments include changes to address the NWPP's tendency to overstate generation in high-flow periods, to account for recent upgrades at our hydroelectric projects, to maintain year-to-year consistency in project operations, to account for encroachment on our Mid-Columbia project shares, and to allow for 2000 irrigation depletion levels.

Q. Why does the NWPP overstate generation on the Company's hydroelectric facilities?

A. The NWPP's regional hydroelectric model is in many ways simplified and therefore does not account for various project operating characteristics. The NWPP model is not granular enough to account for intra-month flow changes. This impact is most significant during the spring months. For example, the Noxon Rapids project has a maximum turbine flow capability of approximately 50,000 cubic feet per second (cfs). The NWPP model will use all water up to 50,000 cfs in a given month to generate power. However, a 50,000 cfs month is not comprised of 28, 29, 30 or 31 days of 50,000 cfs. Instead it is made up of flows that range below and above 50,000 cfs. For example, where flows are 20,000 cfs for the first half of the month and 80,000 cfs the second half, the average flow for the period is 50,000 cfs. The NWPP would assume all of this water went through the generation turbines and made power. In fact, the project would in the first half of the month generate with 20,000 cfs and in the second half of the month it would generate with 50,000 cfs. The additional 30,000 cfs in the second half of the month (80,000 – 50,000 = 30,000), or nearly 30 percent of the monthly total, would be spilled in the actual operation of the project.

Q. Does Noxon Rapids have storage capability to account for such variations in flows?

A. Noxon does have some storage, but not near enough to convert all of the intra-month variability of flows into electric energy. A study completed by BorisMetrics explained that on average our hydroelectric dams on the Spokane and Clark Fork Rivers generate 3.7 aMW less than the NWPP estimates. This study was reviewed and accepted in the 2005 rate case (UE-050482). Its results have been used in the Company's rate filings since that time.

Q. Is the Company now experiencing an even greater difference between actual hydroelectric generation and generation from the NWPP model, than that quantified by BorisMetrics?

A. Yes. Relative to the NWPP data used in previous cases, hydro generation on the Clark Fork projects has been overstated by a significant amount on average. Over the past 20 years actual hydroelectric generation has been 319.72 aMW, 3.2 percent (10 aMW) below the NWPP model results for the 50-year period used in rate modeling. Over the past 10 years generation has been 299.08 aMW, or 10.3 percent (31 aMW) below the NWPP modeled results. Lower results in the past 10 years have been driven primarily by lower-than-average stream flows; however, not all of the reduction is driven by lower stream flows. A portion of the overstatement is caused by the design limitations of the model itself.

Q. Please provide additional detail as to why the 10- and 20-year averages were below the 50-year NWPP study period average?

A. There are a number of reasons. Flows in the 1990s were high relative to history, whereas flows in the most recent 10 years have been low relative to average. Also, half of the 20-year average is affected by the use of operating assumptions from our old Clark Fork operating license. New licensing requirements implemented in 2001 have negatively affected power production on the Clark Fork projects. Poor hydroelectric conditions also have played a role in a number of recent years. Additionally, the Company continues to shift reserve obligations to the Clark Fork as we lose Mid-Columbia generation capacity, and as we respond to a marketplace greatly affected by new variable generation resources (i.e., wind). Upgrades at

Cabinet Gorge and Noxon Rapids have helped to offset these losses, but the statistics explain that generation levels continue to fall over time.

Q. How is hydro generation calculated in this proceeding?

A. For our Mid-Columbia shares, and for the Spokane River, there is no change from previous filings. Generation data are taken from the NWPP Headwater Benefits Study, adjusted downward by the results of the BorisMetrics study for the Spokane River and Encroachment for the Mid-Columbia projects. For the Clark Fork River projects we continue to use NWPP data for the historical record (1929-1978). However, instead of using energy levels calculated by their model, and adjusted by the BorisMetrics study for overstated generation, the NWPP flow data is used as an input in a new model: the Clark Fork Optimization Package.

Q. Please describe the Clark Fork Optimization Package.

A. The Clark Fork Optimization Package is a mixed-integer linear programming-based system emulating the operation of the Company's Clark Fork projects. It was developed in support of the Company's system operations, financial forecasting, and hydro upgrade efforts. Operating on an hourly time-step, it accurately represents individual turbine and reservoir operations. License constraints (e.g., minimum flows, elevation limits) are honored in all periods. The Clark Fork Optimization Package is comprised of four components which are described below.

Q. In what programming language was the model developed?

A. The Clark Fork Optimization Package is a suite of database (Microsoft Access) and spreadsheet (Microsoft Excel) programs. The Excel programs benefit from WhatsBEST!, an Excel Add-In for Linear, Nonlinear, and Integer Modeling and Optimization. WhatsBEST! was developed by Lindo Systems of Chicago, Illinois in 1979.

Q. What is the first component of the Clark Fork Optimization Package?

A. The first component is the Clark Fork Water Budget Model. It looks over the long-term record and optimizes water flow through the projects to maximize generation values. This step is necessary to recognize the storage capabilities inherent in a hydro project. The long-term optimization is simplified to provide present-day computers with the ability to efficiently solve the equations. Each project is represented by one power curve instead of multiple curves representing individual turbines. Model granularity is daily instead of hourly. Project elevation and flow constraints are retained.

Outputs of the Clark Fork Water Budget Model are weekly beginning and ending project elevations for the Noxon Rapids and Cabinet Gorge projects. These elevations are exported to the second module of the Clark Fork Optimization Package—the Clark Fork Optimization Model Input Database. It is discussed below.

Q. What is the source for hydroelectric flows in the Clark Fork Water Budget Model?

A. The source is the 2007-08 NWPP Headwater Benefits Study. To shape the monthly NWPP data Avista used a daily study obtained from the Bonneville Power Administration (BPA). The BPA data were from the U.S. Army Corp of Engineers study re-creating daily historical flows on the Clark Fork River back to 1929 based on today's river system.

Because of the need for daily inflow values that the NWPP does not provide, and the fact that the BPA data is daily, Avista elected to shape the NWPP monthly data using the daily shapes of the BPA study in each month.

Q. What data does the Clark Fork Optimization Model Input Database contain?

A. The Clark Fork Optimization Model Input Database contains the daily inflows and side flows into the Company's Clark Fork River projects described above. It also contains representative hourly market prices enabling the model to maximize generation levels in the higher-valued on-peak periods.

Q. What is the third element of the Clark Fork Optimization Package?

A. The third element is the Clark Fork Optimization Model itself. This hourly model uses a mixed-integer optimization routine to maximize the value of the Clark Fork projects over time. Each project is represented in detail, including individual turbine efficiency curves, physical and license-constrained reservoir elevations, tailrace elevations, and minimum and maximum flow constraints.

The Clark Fork Optimization Model shapes generation into the most economically beneficial time periods using the projects' storage reservoirs. It also maximizes the value of generation by flowing water through the turbines at their most economically efficient points on the power curves.

Q. What is the fourth element of the Clark Fork Optimization Package?

A. The fourth element is the Clark Fork Optimization Model Output Database. This database contains results from the Clark Fork Optimization Model, including hourly turbine discharge and spill flows, hourly generation levels, hourly generation values, and hourly reservoir elevations.

Q. How did the Company ensure the Clark Fork Optimization Package accurately reflects the operations and value of the Clark Fork projects?

A. Once the Clark Fork Optimization Package models were completed, it was benchmarked against the Company's 2000-2009 actual results at the Clark Fork projects to ensure its accuracy.

Q. How did the results compare?

A. The Clark Fork Optimization Package initially over-estimated generation relative to the 2000-2009 periods by approximately 6 percent. This result was expected, as Avista does not operate its projects in isolation. Instead the Company uses the Clark Fork projects to meet its load and reserve needs. There are also times where units are down for maintenance or forced outage. To reconcile the Clark Fork Optimization Package with actual operating history, the power curves for each project were therefore reduced by the 6 percent difference. After the benchmarking process, the model generated just over 100 percent of actual generation levels during the 2000-2009 period.

Q. How is the generation then used for ratemaking purposes?

A. The generation levels for each project (Mid-Columbia, Spokane River, and Clark Fork) are input into the dispatch model (AURORAxmp) where Avista's portfolio value is quantified for ratemaking purposes.

Q. Are the models included in the Company's filing?

A. Yes. All four components of the Clark Fork Optimization Package are included in my workpapers, including all input and output data.

Q. Does the Clark Fork Optimization Package account for recent upgrades at the Noxon Rapids project?

A. Yes. Once the original model was benchmarked against recent generation years that did not benefit from upgrades at Noxon, the three newly upgraded units (1, 2, and 3) were input into the model to reflect the higher anticipated generation levels. As Unit 2 will not enter service until April 1, 2011, all proforma periods prior to April 2011 include upgrades only to Units 1 and 3.

Q. How much additional generation did the new units provide based on your modeling?

A. The Company evaluated generation levels with the old Noxon units 1 through 3, and the newly upgraded units over the 50-year period for this case. Generation levels from the upgrades increased by a total of 35,778 MWh (4.08 aMW), or 1.3 percent.

Q. How much additional generation does the new Unit 2 provide?

A. On an annual basis the new Unit 2 included in this case generates 10,326 MWh on average over the 50-year period, or 1.18 aMW.

Q. Why did the Company not use similar models in this case for the Spokane River and Mid-Columbia projects?

A. The Clark Fork Optimization Package is the product of several years of work by Avista. The Company has not yet attempted to build a model for the Mid-Columbia due to those projects' significant reliance on upstream (e.g., Grand Coulee Dam) projects that greatly affect their output. A model for the Spokane River projects is under development but is not yet ready for use. The Company hopes to have a working version for the Spokane River system prior to its next rate proceeding. We will subsequently examine a model for the Mid-Columbia projects.

Q. Please explain why the Company developed the Clark Fork Optimization Package.

A. The Clark Fork Optimization Package is the culmination of nearly ten years of work by the Company to bring in-house a tool to enable true optimization of our hydro facilities. In

2002 the Company acquired the Vista suite from Synexus Global. This tool was used to evaluate system operations and support upgrades at our Noxon Rapids and Cabinet Gorge projects. It also was used to evaluate various Spokane River project upgrades. Because of some problems inherent to the Vista model, and very slow solution times, it was retired in the middle of the last decade. We then evaluated other options in the marketplace, and the Company acquired Riverware from the University of Colorado at Boulder. After working with this tool over a number of years it became apparent that it cannot meet our need for efficient unit-level dispatch modeling.

Due to the apparent lack of a strong package for hydro modeling in the marketplace, the Company began developing the Clark Fork Optimization Package in the middle of 2009.

Q. How is the Company using the new Clark Fork Optimization Package in its business operations, and how does it intend to use the tool into the future?

A. The Clark Fork Optimization Package is an essential tool to assist the Company with optimizing hydro system operations, both in short- and long-term planning. Its results are also used for Company budgets, hydro project market valuation studies, and upgrade studies. Given its solution efficiency, it is possible to run large hydro-flow records through it, as is necessary for rate filings such this.

The Company anticipates using its new model to analyze opportunities to increase the value of the Clark Fork projects and lower overall system costs to customers. With this model there is now a potential to analyze a coordination agreement between Clark Fork River project operators that would be similar to the Pacific Northwest Coordination Agreement. Initiation of discussions on this a potential agreement between the various parties with projects on the river has been hampered to a large extent by the lack of a good means to model the values of coordination.

Q. How does the AURORAxmp 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 69 percent of Clark Fork hydro generation during on-peak hours (based on the average of the 50 year hydro record). Since on-peak hours represent only 57 percent of the year, this demonstrates a substantial shift of hydro resources to the more valuable on-peak hours. This is identical to the 5-year average of on-peak hydroelectric generation at the Clark Fork through 2009. Similar performance is achieved for the Spokane and Mid-Columbia projects.

IV. HYDRO BIASING

Q. What is Hydro Biasing, and what is the Company's position on it?

A. In recent cases certain parties have proposed selectively removing portions of the full stream flow record if those portions exceed certain criteria, hereinafter referred to as "Hydro Biasing." With recent modifications to incorporate asymmetry in the sharing bands of the Energy Recovery Mechanism, Hydro Biasing is a solution to a problem that no longer exists. Further, Hydro Biasing creates a continuing under-representation of our expected future costs, and it thereby prevents the Company from a reasonable opportunity to earn a fair return on its investments.

Q. What is the nature of the recent Hydro Biasing proposals?

A. Two approaches have been previously suggested. The first approach is a simple removal of all water years in the hydroelectric record that fall outside of some specified range. The second approach is removing specific months from the hydroelectric record where they fall outside of a given range.

Once an approach has been identified, the level of biasing has to be decided. For example, using annual Hydro Biasing at "one standard deviation" would eliminate nearly half (23 years, or 46 percent) of the 50-year hydroelectric record accepted by this Commission.[1] Hydro Biasing at the same level on a monthly basis eliminates between 16 percent and 44 percent of the 50-year hydrological record, depending upon the month. In total, nearly a third of the months are removed when looked at from a monthly Hydro Biasing basis at one standard deviation.

[1] A standard deviation describes the underlying variability of population's data set. One standard deviation from the mean, or average, contains approximately 2/3 of the population.

Q. Does the Company believe it makes sense to eliminate as much as 46 percent of the historical record in setting rates?

A. No. Hard bargaining in recent cases has resulted in settlements that use a water-year record from 1929 through 1978. This period excludes a substantial percentage of the historical record after 1978, or 38 percent (31 years) of available data. Eliminating another 46 percent through Hydro Biasing as described above would mean that the Commission would be setting rates for the Company based on one one-third (27 years) of the 81-year historical record. We believe this is not reasonable or statistically supportable for ratemaking purposes. It also has adverse economic consequences for the Company that I will explain later in my testimony. Further, the present Energy Recovery Mechanism (ERM) already addresses the concerns that these parties believe are corrected by using a Hydro Biasing concept.

Q. What are the concerns that have been remedied by the ERM?

A. The Company is aware of two primary concerns related to the over-collection of revenue relative to proforma expenses. The first concern is that, without a Hydro Biasing method in place, the Company would have the opportunity to benefit from near-average hydro in most years, but then approach the Commission for additional recovery in the worst hydro years. The second concern is that the ERM mechanism itself causes over-collection to occur.

Parties have argued that additional cost recovery during extremely adverse hydro conditions represents a second bite at the apple for Avista. In other words, the Company recovers costs based on the average of the historical record in most years, but in an extremely adverse condition the Company comes back for additional recovery instead of bearing the bad year that helped set the average revenue requirement. Absent the ERM this additional recovery would mean that over a longer period of time the Company would over-collect. This concept is best conveyed in an example. Please refer to Table 1 below.

Table No. 1 – Revenue Requirement Illustration 1

Year	Author-ized	Actual Costs	Diff-erence	Addl. Recovery	Net Difference
1	130	95	-35	0	-35
2	130	110	-20	0	-20
3	130	140	10	0	10
4	130	105	-25	0	-25
5	130	200	70	-70	0
Avg	130	130	0	-14	-14

This table shows a 5-year historical hydro record with an average revenue requirement of $130. Actual costs year to year vary from a low of $95 (Company incurs costs $35 below the authorized revenue level) to a high of $200 (Company incurs costs $70 above the authorized level), but on average the revenue requirement is equal to the authorized level. Assuming that the Company does not request additional compensation in Year 5 where costs are greatly above other years, customers are made whole over the five-year period. However, if the Commission provided additional recovery in Year 5 equal to the difference between the authorized level and actual costs, the Company would over-collect $70 in that year, or an amount equal to $14 if averaged over the 5 years of the example.

However, the ERM is designed to address the full range of the variability of costs reflected in the Dispatch Model. The Dispatch Model calculates average net power cost in this case as $97.6 million (WA share), and under the most adverse hydroelectric condition, the net cost is $135.5 million (WA share). If this extreme adverse condition were to occur, the additional costs would flow through the ERM, with the Company absorbing $9.8 million. The remaining $28.1 million would be deferred with an opportunity for rate recovery.

A proposal to arbitrarily throw out a portion of the hydroelectric record that the Company could reasonably expect to reoccur over time would inappropriately bias the determination of the average. Furthermore, references to power supply costs incurred during the 2000-01 Energy Crisis should not be used to modify modeled costs in this case; the unique circumstances of the Energy Crisis are well beyond anything modeled here. The 50-year record used in this case reflects normal variation that would be expected to occur in the marketplace when fundamentals are in balance (i.e., loads and resources are similarly matched, as was not the case during the energy crisis).

Q. Please explain the second concern.

A. The second concern that some parties have is the perception that the ERM mechanism creates an opportunity for the Company to over-collect its costs relative to authorized levels, even where the Company does not request additional recovery in bad water years. As I will illustrate and explain below, this is simply not true. Table 2 below illustrates three scenarios based on our filing.

Table No. 2 – ERM Scenarios (Washington Share Only)

Scenario	50-Year Average	Filtered Average	Diff-erence	No Biasing	With Biasing
No ERM	97,571	96,180	1,391	0	1,391
50/50	97,571	96,180	1,391	(414)	1,551
50/75	97,571	96,180	1,391	125	1,830

The 50-year average power supply expense is $97.571 million (WA share). Absent an ERM mechanism the average revenue requirement over the 50-year study period is exactly $97.571 million; in this scenario the Company earns exactly what its average costs are (see “No Biasing” column). However, in the scenario where the original symmetrical ERM sharing bands were in place (i.e., a 50/50 split of costs in the second band), the Company would incur expenses equal to $414,000 less than the modeled power supply expenses that base rates were set upon. In other words, the Company would recover $414,000 more than authorized on average over time with 50/50 symmetrical sharing bands.

Through a settlement agreement approved by the Commission in Docket No. UE-080416, however, Avista agreed to <u>asymmetrical</u> sharing bands to address this specific issue. Under this scenario, the sharing in years with higher costs remain at 50 percent for customers and the Company, but in years where the Company has lower than average costs due to higher hydro or other events, customers retain 75 percent of the value and the Company only retain 25 percent. The revised ERM sharing mechanism reversed the over-recovery and, in fact, now has a modest bias against the utility of $125,000 per year, as shown in Table 2 above. In other words, the initial over-collection with the symmetrical sharing bands has been changed to an under-collection as a result of the application of the asymmetrical bands.

Therefore, the following conclusions can be drawn from Table 2 above where Hydro Biasing is <u>not adopted</u> for the 50-year hydro study:

1. Without the ERM, the Company would recover its costs over time using the 50-year average;
2. The ERM, with 50/50 symmetrical sharing bands would allow the Company, on average over time, to over-recover its costs by $414,000 per year; and
3. The current asymmetrical sharing bands (50/50 customer/Company for higher costs, and 75/25 customer/Company for lower costs) will cause the Company, on average over time, to under-recover its costs by $125,000 per year.

The asymmetrical sharing bands, <u>plus</u> a Hydro Biasing adjustment, would further compound the under-recovery of costs for the Company and cause the Company, on average, to under-recover its costs by $1.830 million per year (see Column 6 of Table No. 2). This is explained further below.

Q. How does Hydro Biasing negatively affect the Company?

A. Hydro Biasing on a <u>monthly</u> basis at the one standard deviation level, the preferred method of Commission Staff and ICNU in our previous two rate proceedings, would increase generation by 1.5 aMW, and lower filed costs by approximately $614,000 on a system basis. Under a biasing approach, the Company would expect to under-collect its costs over time by this amount.

<u>Annual Hydro Biasing</u>, as illustrated in Table No. 2 above, is even more costly to the Company because of the times of the year where hydroelectric generation is reduced. As shown in Table 2, the impact of Hydro Biasing alone (i.e., before application of the ERM) is a $1.391 million lower annual Washington revenue requirement, reflecting the difference between the 50-year average and the average where periods with hydroelectric conditions above or below one standard deviation are removed (refer to Column 4 of Table No. 2). Generation is increased by 3.7 aMW from the 50-year average. Lowering the average revenue requirement for Washington by $1.391 million per year compounds the under-recovery of costs. It is important to note that this level of under-recovery falls entirely within the dead band where the Company absorbs all of the $1.391 million impact. The Company would have no means to recover all of its power supply expenses. Applying the ERM magnifies the impact from $1.391 million to $1.830 million of under-recovery under the present sharing methodology.

Q. Should the Commission adopt Hydro Biasing?

A. No. First, the ERM is designed to address all of the variability modeled in the 50-year hydro study included in the Dispatch Model. And with the recent adoption of the asymmetrical sharing band, the Company already under-recovers its costs. Therefore, the only result of Hydro Biasing will be a further under-collection of costs by the Company. As the impact falls within the dead band, where the Company absorbs the entire impact of Hydro Biasing, the net impact of Hydro Biasing is continuing under-recovery.

Q. Did this Commission previously address the use of Hydro Biasing in the context of a power cost adjustment mechanism?

A. Yes. In its Order 08, dated June 21, 2007, in PacifiCorp's rate case (Docket No.(s) UE-061546/UE-060817), the Commission commented on the use of Hydro Biasing, then termed "water-year filtering", in the context of a power cost adjustment mechanism:

> We find that filtering water years is appropriate in the context of a PCAM, but that such filtering must reflect whether the distribution of variability in power costs is symmetrical or skewed as well as how the dead band and sharing bands are designed to reflect asymmetry in the risks and benefits that may accrue to both customers and Company. (Order 08, para. 101)

It went on to conclude that "any water-year adjustment for power cost normalization must be consistent with the way the PCAM design reflects the asymmetric power cost distribution." (Id., para. 111) With the recent adoption of <u>asymmetrical</u> sharing bands in Avista's ERM (Docket No. UE-080416), the additional use of Hydro Biasing (i.e., filtering of water years) would only compound the Company's under-recovery of costs.

V. OTHER KEY MODELING ASSUMPTIONS

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 from October 1, 2009 to December 31, 2009 of calendar-year 2011 monthly forward prices. Natural gas prices used in the Dispatch Model are presented below in Table No 3.

Table No. 3 – Pro Forma Natural Gas Prices

Basin	2011 $/dth	Basin	2011 $/dth
AECO	6.060	PG&E CITY	6.820
CHICAGO	6.623	RATHDRUM	6.381
CIG	5.968	SJUAN BASIN	6.086
EL PASO	6.166	SOCAL	6.379
MALIN	6.461	STANFIELD	6.381
NECT	6.686	SUMAS	6.479
NWPC RM	5.989	HENRY HUB	6.546

Q. What is the Company's assumption for rate period loads?

A. Rate period loads (January 2011 through December 2011) used in this case are taken from the Company's load forecast completed in July 2009. As this load is generated using "normal weather," it eliminates the need for a weather-normalization adjustment. The Company's latest energy and capacity loads and resources tabulations (L&Rs) are attached in Exhibit No.___(CGK-2). As the L&Rs show, system loads are expected to equal 1,130 aMW in 2011. Removing the 2009 actual (test year) generation from the Clearwater (previously known as Potlatch) cogeneration facility, system loads are 1,077.9 aMW as filed in this proceeding.

Q. Please discuss the availability assumptions for your thermal and gas generating facilities.

A. For baseload generating facilities such as Coyote Springs 2, Kettle Falls Generating Station, and Colstrip, we use a 5-year average through 2009 to estimate long-run operating performance. The following table summarizes the average forced outage rates for each of the Company's thermal and gas generation facilities.

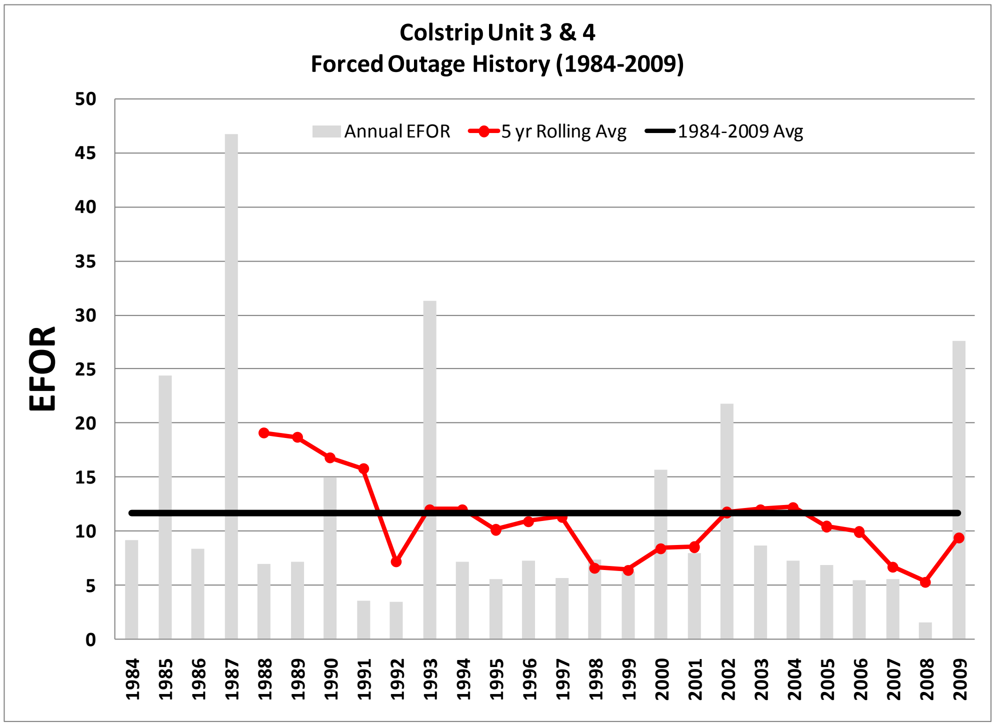
Table No. 4 – Equivalent Forced Outage Rates (EFOR) Of Avista Thermal and Gas Plants

Plant	EFOR	Plant	EFOR
Colstrip	9.36%	Rathdrum	5.00%
Coyote Springs	5.07%	Northeast	5.00%
Lancaster	3.00%	Kettle Falls	1.58%
Boulder Park	15.00%	Kettle Falls CT	5.00%

Q. Colstrip had an extended outage in 2009. Would it be reasonable to exclude this single year from the average?

A. No. In the past, various parties have advocated elimination of years where the Colstrip plant had a high forced outage rate, assuming that such years were abnormal and should not be expected to re-occur. This is in fact not the case. The 5-year average of 9.36 percent falls well below the 11.6 percent lifetime plant average. In the 25-year history of Colstrip operations there have been seven years (one event every 3.7 years) where forced outage rates exceed 10 percent. It is therefore not uncommon for some years to have outages like the one experienced in 2009. See Chart No. 1 for a history of forced outages at Colstrip.

Chart No. 1 – Colstrip Forced Outage History



Q. Please provide a summary of the monthly and average Northwest forward natural gas and electricity prices that directly affect proforma costs.

A. Table No. 5 presents monthly modeled natural gas and electricity prices for this case.

Table No. 5 – Dispatch Model Prices Summary

Month	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Flat 7x24 Mid-C ($/MWh)	Month	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Flat 7x24 Mid-C ($/MWh)
Jan-11	6.70	7.02	56.56	Jul-11	6.14	6.44	47.13
Feb-11	6.70	7.02	55.92	Aug-11	6.21	6.50	56.66
Mar-11	6.53	6.84	50.94	Sep-11	6.24	6.54	54.61
Apr-11	6.05	6.34	40.84	Oct-11	6.34	6.64	50.23
May-11	6.01	6.30	32.57	Nov-11	6.64	6.95	56.16
Jun-11	6.07	6.36	32.27	Dec-11	6.98	7.30	62.13
				Average	**6.38**	**6.69**	**49.66**

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. This being said, they generally are very close as in this filing. 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 $54.90/MWh on-peak and $43.11/MWh off-peak (based on average forwards between 10/1/2009 and 12/31/2009). The average Mid-Columbia price from the Dispatch Model is $54.76/MWh on-peak and $42.83/MWh off-peak.

VI. DEMAND CLASSIFICATION

Q. Witness Knox explains that the Company is changing its methodology for allocating production costs between capacity and energy based on your work. Please explain your concerns with the present methodology and what you propose as a better way to allocate production costs.

A. The historical method to allocate production costs goes through the various FERC accounts and attempts to determine which costs are for demand and which are for energy. As an example, all thermal fuel in FERC account 501 is allocated to energy production, and all "Other" production costs are allocated to demand. Unfortunately, the problem is not this simple. Some of the "Other" costs are almost certainly related to the production of energy and, possibly more surprising to some, various fuel costs can be related to providing capacity (demand).

Q. How can some of the costs in your example be considered energy?

A. To produce energy it is necessary to maintain a generation plant in a ready state to do so. The "Other" category is an excellent example of a somewhat arbitrary allocation to demand that is done for lack of any better approach. The "Other" category for both production plant (300 series) and O&M (500 series) includes our gas-fired plants and the Lancaster agreement. The "Other" category is allocated 100 percent demand. Because of this the Company has historically removed our Coyote Springs 2 gas-fired CCCT plant from the "Other" category and instead allocated its costs based on the overall Thermal Peak Credit figure. But other plants are not broken out this way. Boulder Park, Rathdrum and Northeast are all allocated 100 percent to demand by being in the "Other" category, yet clearly a portion of their plant and O&M costs are attributable to energy production. It is likely that a portion of "Other" expenses are indeed to the benefit of energy production, yet the old allocation method assumed all such costs are attributable to demand.

Q. How can a fuel cost be classified as demand?

A. Demand, or capacity, is really the production of energy at the time of system peak. Fuel is consumed during periods of peak operation. It would be unreasonable to not consider this fact. And simply because the majority of a fuel expense is incurred outside of peak operating periods does not mean that no fuel should be allocated to demand.

Q. Do you have any other concerns about the present demand allocation methodology?

A. Yes. Presently all of our generation assets are melded together to create an allocation. Further, a simple accounting methodology is employed to estimate what it might cost to construct our older facilities today. But it is not realistic to assume that historical investments represent our present costs of capacity (demand). Such allocations should be based on the decisions we are making today, and on the costs we incur today when customers consume electrical energy during times of system peak. Instead of trying to create an incremental demand cost through a complicated and potentially inaccurate escalation of historical expenses, we should instead use present information for plants we are building to meet new customer demands.

Q. Please explain the Company's recommended method for classifying electricity production costs between energy and demand.

A. The Company believes we should link the classification methodology to the Integrated Resource Plan (IRP). The IRP process is an exercise to meet customer load growth in a least-cost fashion. Central to the equation is the level of our customers' coincident peak demand. We construct a least-cost mix of resources providing both the energy and capacity.

Q. What resource does the Company propose be used for splitting demand and energy costs from overall production expenses?

A. We believe that we should use the incremental capacity resource from our latest IRP—a gas-fired CCCT. The Company, using its IRP models, calculated the costs of capacity and energy from this resource, and used that figure to allocate overall production costs.

Q. How did the Company determine a split between energy and capacity for the incremental resource?

A. For the IRP the Company models the Western Interconnect wholesale power marketplace using AURORAxmp. AURORAxmp dispatches available resources against electricity loads on an hourly basis. The IRP uses AURORAxmp to look at costs out 20 years and "mark-to-market" (MTM) each potential resource option reasonably available to the

Company in the future. The dispatched value of the CCCT (i.e., market sales price less fuel and variable maintenance and operation costs) is tracked hourly over the 20-year IRP timeframe. Additionally, for the IRP the Company models the 20-year future over 250 Monte Carlo iterations to reflect volatility created by various factors including natural gas prices, load variability and forced outage rates. In other words, for each of the 20 years evaluated for the IRP there are 250 MTM values for the CCCT. The annual average MTM figures represent the energy value generated by the plant. Remaining costs not recovered in the wholesale marketplace are defined as capacity. The ratio of those costs remaining after dispatch into the wholesale marketplace (MTM values) relative to the entire cost of the CCCT plant equals the share of production costs then attributed to demand in the cost of service models.

Q. What were the results of your analysis?

A. The analysis allocates 38.1 percent of production costs to demand. Company witness Knox discusses how this demand allocator compares with that derived from the prior peak-credit methodology.

Q. Where are the calculations referenced above contained?

A. The calculations are contained in my work papers in an Excel file called "Demand_Classification_Final." A summary of the results is presented in Exhibit No. ___(CGK-3)

Q. How should the demand allocation be applied to production costs?

A. Because the analysis does not differentiate between fixed and variable costs, but instead evaluates all such costs, it should be applied across the board to all production costs.

VII. 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 Confidential Exhibit No. ___(CGK-4C) and were 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. Does this conclude your pre-filed direct testimony?

A. Yes, it does.