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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-09-01 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 and 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, 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 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 2019. Schedule 2 provides summary output from the Dispatch Model. All information contained in the exhibits 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 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 July 1, 2009 through June 30, 2010. 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 9.3.1004, and the latest available database for it (North_American_DB_2008-03).

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 the Company's 2003, 2005, 2007, 2009 Integrated Resource Plans ("IRPs"), our 2005, 2007, and 2008 rate filings in the State of Washington and our 2004 and 2008 general rate case filings before this Commission. The tool is also used for various resource evaluations, market forecasting, and requests for proposals.

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

A. $\text{AURORA}_{\text{XMP}}$ is used all across North America. In the Northwest specifically, $\text{AURORA}_{\text{XMP}}$ 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, 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 2008 on-peak prices through mid-December were 23% higher than off-peak prices. In 2007 the difference was 25%. Forward prices for 2010 were 28% at the time this case was prepared. For comparison, Dispatch Model on-peak prices for the pro forma period average 28% 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 with available resources 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 from September 1, 2008 to November 30, 2008 of July 2009 through June 2010 monthly forward prices.

Natural gas prices used in the Dispatch Model are presented below in Table No 1.

Table No. 1 - Pro Forma Natural Gas Prices

Basin	Price ($/dth)	Basin	Price ($/dth)
AECO	7.31	Stanfield	7.67
Malin	7.75	Sumas	7.83
Spokane	8.03	Henry Hub	8.08
Rockies	5.59	Topock	7.49

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

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

A. Rate period loads (July 2009 through June 2010) used in this case are taken from the Company's 2009 load forecast completed in July 2008. 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. 5, Schedule 1. As the L&Rs show, system loads are expected to equal 1,134 aMW including a large co-generator's entire load. For this filing, system loads are reduced by 49 aMW of co-generation by the large industrial customer load located in Idaho. This adjustment lowers the rate period loads to 1,085 aMW.

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 70% of Clark Fork 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 identical to the 5-year average of on-peak hydroelectric generation at the Clark Fork through

2008. Similar performance is achieved for the Spokane and Mid-Columbia projects.

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 Summary

Month	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Flat (7 x 24) Mid-C ($/MWh)	Month	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Flat (7 x 24) Mid-C ($/MWh)
Jul-09	7.18	7.51	57.01	Jan-10	8.38	8.76	67.51
Aug-09	7.29	7.63	63.09	Feb-10	8.36	8.74	62.47
Sep-09	7.29	7.64	60.64	Mar-10	8.12	8.50	57.69
Oct-09	7.34	7.68	55.47	Apr-10	7.41	7.76	49.74
Nov-09	7.75	8.11	59.58	May-10	7.36	7.70	39.36
Dec-09	8.13	8.50	71.66	Jun-10	7.44	7.79	34.74
				Average	**7.67**	**8.03**	**56.59**

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 $63.01/MWh on-peak and $49.26/MWh off-peak (based on average forwards between 9/1/2008 and 11/30/2008). The average Mid-Columbia price from the Dispatch Model is $62.52/MWh on-peak and $48.68/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 any of the recent Noxon Rapids upgrades?

A. No, the NWPP study does not include the Cabinet Unit 4 or the Noxon Rapids 1 and 3 upgrades. The data will be included in our next data submittal to the NWPP. I expect the upgrade to be reflected in the 2009 NWPP study.

Q. How have you accounted for the upgrades in the pro forma?

A. The Cabinet Unit 4 upgrade is expected to generate an additional 1.98 aMW in an average water year; Noxon Rapids Units 1 and 2 are expected to generate 3.3 average megawatts of additional energy in an average water year. To account for this energy in the pro forma, the unit sizes are increased to reflect the corrected amount of energy. The Dispatch Model then generates at the upgraded energy and capacity levels when the units are dispatched.

Q. Company witness Storro discusses a new generation resource that will enter Avista's supply portfolio in 2010. Is this resource included in the Dispatch Model and the Proforma?

A. The 270-MW gas-fired combined-cycle generation resource you are referring to entered commercial service in 2001, though it was not owned or operated by the utility arm of Avista Corporation. It has been in our Dispatch Model since we began using the tool in 2002. However, we have never included the resource in our portfolio of resources that are tracked for ratemaking purposes. Though we assume operational control over the facility in January 2010, we have not elected to include it in this filing because the resource doesn't become available to us until the midpoint of the proforma period. As Company witness Johnson explains in more detail in his testimony, the Company is proposing to track the costs and benefits of this resource through the PCA mechanism when it enters our resource portfolio in January 2010.

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 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.

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FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Load and Resource Balance (aMW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy Position											
REQUIREMENTS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Native Load	-1,119	-1,148	-1,171	-1,189	-1,202	-1,222	-1,252	-1,270	-1,289	-1,311	-1,329
2 Contract Obligations	-140	-139	-139	-139	-139	-139	-64	-64	-12	-11	-11
3 Total Requirements	-1,259	-1,287	-1,310	-1,328	-1,341	-1,361	-1,315	-1,334	-1,301	-1,322	-1,339
RESOURCES											
4 Contract Rights	367	604	521	487	495	473	420	410	368	346	347
5 Hydro	555	538	520	509	511	511	511	511	511	507	496
6 Thermal Resources	527	528	528	527	526	542	517	526	528	519	520
7 Total Resources	1,449	1,670	1,569	1,522	1,532	1,526	1,448	1,446	1,407	1,371	1,363
8 **POSITION**	**191**	**382**	**259**	**194**	**191**	**165**	**133**	**112**	**106**	**49**	**24**
CONTINGENCY PLANNING											
9 Contingency Total	-226	-227	-228	-224	-225	-226	-227	-227	-228	-229	-212
10 Peaking Resources	153	153	153	153	144	153	153	153	153	153	153
11 **CONTINGENCY NET POSITION**	**118**	**309**	**185**	**123**	**110**	**93**	**59**	**38**	**31**	**-27**	**-35**

Exhibit No. 5
Case No. AVU-E-09-01
C. Kalich, Avista
Schedule 1, p. 1 of 1

Dispatch Model Proforma Costs ($000s)

1		Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	**Hydro Projects**													
3	Clark Fork	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Cabinet Gorge	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Noxon Rapids	0	0	0	0	0	0	0	0	0	0	0	0	0
6	*TOTAL*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
7														
8	Spokane River	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Little Falls	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Long Lake	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Monroe Street	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Nine Mile	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Post Falls	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Upper Falls	0	0	0	0	0	0	0	0	0	0	0	0	0
15	*TOTAL*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
16														
17	Mid-Columbia- Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Priest Rapids	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Rocky Reach	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Wanapum	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Wells	0	0	0	0	0	0	0	0	0	0	0	0	0
22	*TOTAL*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
23														
24	**Thermals**													
25	Boulder Park	37	0	0	0	0	5	0	15	16	0	0	0	0
26	Colstrip	18,106	1,719	1,573	1,727	1,551	1,028	1,063	1,582	1,601	1,549	1,588	1,549	1,575
27	Coyote Springs 2	70,099	7,260	6,781	6,895	3,724	1,672	2,171	6,176	7,154	6,740	6,641	7,131	7,754
28	Kettle Falls	11,075	1,279	1,206	1,318	305	0	0	1,166	1,175	1,138	1,176	1,138	1,175
29	Kettle Falls CT	76	2	5	1	4	13	4	23	21	1	0	1	0
30	Lancaster	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Northeast	40	0	0	0	0	0	0	17	23	0	0	0	0
32	Rathdrum	249	0	0	0	0	20	3	108	118	0	0	0	0
33	*TOTAL*	*99,682*	*10,261*	*9,565*	*9,941*	*5,584*	*2,739*	*3,241*	*9,087*	*10,107*	*9,428*	*9,404*	*9,820*	*10,505*
34														
35	***RESOURCE TOTAL***	***99,682***	***10,261***	***9,565***	***9,941***	***5,584***	***2,739***	***3,241***	***9,087***	***10,107***	***9,428***	***9,404***	***9,820***	***10,505***
36														
37	**Contracts**													
38	Black Creek	162	0	0	0	0	0	0	0	0	0	162	0	0
39	DOPD	783	45	41	62	82	119	126	92	66	37	44	34	35
40	Market Contract 1	7,556	642	580	642	621	642	621	642	642	621	642	621	642
41	Can Ent Return	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Grant County	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Clark Fork LLC	101	8	8	8	13	16	15	11	6	3	3	5	7
44	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
45	Grant Displacement	5,449	397	385	384	504	522	431	516	438	434	454	473	510
46	Stimson Lumber	2,084	191	182	161	148	144	139	181	198	187	178	193	182
47	Jim Ford Creek	228	39	49	38	33	19	9	0	0	0	1	11	30
48	John Day Creek	81	4	2	2	3	11	14	12	8	6	5	8	6
49	Meyers Falls	409	36	41	50	49	51	46	24	12	14	23	30	32
50	Nichols Pumping	(3,346)	(339)	(283)	(290)	(242)	(198)	(169)	(286)	(317)	(295)	(279)	(290)	(360)
51	Colstrip Start Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
52	PGE CapExch	0	0	0	0	0	0	0	0	0	0	0	0	0
53	Phillips Ranch	1	0	0	0	0	0	0	1	0	0	0	0	0
54	Potlatch	0	0	0	0	0	0	0	0	0	0	0	0	0
55	Wind Contract	2,933	258	201	302	265	256	304	245	246	206	229	236	185
56	Load Following Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
57	Sheep Creek	396	28	30	44	50	45	40	42	22	19	21	26	28
58	Upriver	2,090	271	266	265	255	250	191	66	(40)	28	105	169	263
59	WNP-3	14,347	2,963	2,676	1,463	1,415	0	0	0	0	0	0	2,867	2,963
60	ST Purchases	30,994	0	0	0	0	0	0	6,010	5,943	5,807	4,472	4,290	4,472
61	ST Sales	(12,721)	0	0	0	0	0	0	(3,573)	(3,492)	(3,447)	(755)	(699)	(755)
62	SMUD	(5,818)	(179)	(130)	(163)	(173)	(560)	(746)	(752)	(682)	(642)	(619)	(587)	(585)
63	Thompson River Co-Gen	0	0	0	0	0	0	0	0	0	0	0	0	0
64	*TOTAL*	*65,919*	*6,077*	*5,596*	*4,683*	*4,684*	*3,032*	*2,680*	*4,944*	*4,765*	*4,638*	*6,402*	*9,049*	*9,369*
65														
66	**Market Transactions**													
67	Market Purchases	51,202	8,765	5,690	4,443	2,640	732	582	1,763	6,521	4,646	5,563	4,588	5,269
68	Market Sales	(53,641)	(2,242)	(2,309)	(4,341)	(5,065)	(5,736)	(6,962)	(9,794)	(2,504)	(2,817)	(2,664)	(4,475)	(4,731)
69	*TOTAL*	*(2,439)*	*6,523*	*3,381*	*102*	*(2,426)*	*(5,004)*	*(6,380)*	*(8,031)*	*4,017*	*1,828*	*2,899*	*113*	*538*
70														
71	***Fuel and Market Only***	**97,243**	**16,785**	**12,946**	**10,043**	**3,158**	**(2,265)**	**(3,139)**	**1,056**	**14,124**	**11,257**	**12,303**	**9,932**	**11,043**
72														
73	**Adjustments**													
74	Coyote Springs 2 Start Fuel	125	13	10	4	5	21	54	12	2	0	1	3	1
75	Rathdrum Start Fuel	26	0	0	0	0	2	1	11	11	0	0	0	0
76	Lancaster Start Fuel	0	0	0	0	0	0	0	0	0	0	0	0	0
77	Northeast Lost Margin	21	1	5	0	1	4	1	0	6	0	1	2	1
78	Coyote Springs 2 Fuel Cost	(1,810)	(174)	(149)	(127)	(101)	(46)	(60)	(193)	(251)	(214)	(159)	(155)	(181)
79	Lancaster Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
80	**Total Adjustments**	**(1,639)**	**(161)**	**(134)**	**(123)**	**(95)**	**(19)**	**(5)**	**(170)**	**(231)**	**(214)**	**(157)**	**(151)**	**(179)**
81														
82	**Adjusted Fuel & Market**	**95,604**	**16,624**	**12,812**	**9,920**	**3,063**	**-2,284**	**-3,143**	**886**	**13,893**	**11,043**	**12,146**	**9,782**	**10,863**

Exhibit No. 5
Case No. AVU-E-09-01
C. Kalich, Avista
Schedule 2, p. 1 of 3

Dispatch Model Proforma Generation (aMW)

1		Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	**Hydro Projects**													
3	Clark Fork	325.9	246.0	284.9	236.2	367.2	648.5	681.2	450.7	244.4	166.9	140.8	166.3	275.8
4	Cabinet Gorge	125.3	100.4	118.0	98.2	148.7	226.3	228.3	178.1	99.9	67.9	58.0	68.2	111.3
5	Noxon Rapids	200.6	145.6	167.0	137.9	218.5	422.2	452.9	272.7	144.4	99.0	82.8	98.1	164.6
6	*TOTAL (aMW)*	*325.9*	*246.0*	*284.9*	*236.2*	*367.2*	*648.5*	*681.2*	*450.7*	*244.4*	*166.9*	*140.8*	*166.3*	*275.8*
7														
8	Spokane River	125.6	138.4	143.5	158.7	169.1	167.9	155.6	98.8	55.0	77.3	95.9	119.0	130.4
9	Little Falls	23.5	27.4	27.9	30.6	32.4	32.2	29.6	17.5	9.7	13.0	16.3	21.5	24.0
10	Long Lake	58.7	66.5	67.1	75.4	82.7	83.3	74.7	43.9	25.4	33.2	40.9	52.8	59.5
11	Monroe Street	11.7	11.9	12.6	13.4	13.6	13.6	13.2	10.6	5.9	9.4	11.2	12.2	12.6
12	Nine Mile	13.3	13.7	15.4	16.7	17.7	16.6	16.2	11.2	5.8	8.3	10.9	13.2	14.5
13	Post Falls	9.8	10.3	11.5	13.4	13.7	13.5	12.9	7.1	2.8	5.3	7.3	9.9	10.4
14	Upper Falls	8.6	8.7	9.0	9.2	8.9	8.7	9.0	8.5	5.4	8.2	9.2	9.3	9.4
15	*TOTAL (aMW)*	*125.6*	*138.4*	*143.5*	*158.7*	*169.1*	*167.9*	*155.6*	*98.8*	*55.0*	*77.3*	*95.9*	*119.0*	*130.4*
16														
17	Mid-Columbia- Contracts	101.7	126.1	102.3	81.5	96.5	104.0	119.3	128.2	99.8	77.4	87.5	91.7	105.6
18	Priest Rapids	19.2	30.6	25.3	19.1	17.5	12.7	18.5	14.4	13.9	12.4	13.9	24.5	28.4
19	Rocky Reach	20.3	25.8	19.7	16.1	21.8	22.4	26.5	25.1	21.5	14.0	15.7	16.6	18.8
20	Wanapum	27.5	27.4	23.3	18.8	22.9	26.7	29.9	46.8	27.7	27.1	31.0	22.2	26.1
21	Wells	34.6	42.3	33.9	27.4	34.2	42.1	44.5	41.9	36.7	23.9	26.9	28.4	32.3
22	*TOTAL (aMW)*	*101.7*	*126.1*	*102.3*	*81.5*	*96.5*	*104.0*	*119.3*	*128.2*	*99.8*	*77.4*	*87.5*	*91.7*	*105.6*
23														
24	*TOTAL*	*553.2*	*510.5*	*530.7*	*476.3*	*632.8*	*920.4*	*956.1*	*677.8*	*399.1*	*321.6*	*324.2*	*377.0*	*511.8*
25														
26	**Thermals**													
27	Boulder Park	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.3	0.3	0.0	0.0	0.0	0.0
28	Colstrip	190.5	203.6	206.3	204.6	189.9	121.7	130.2	203.9	206.3	206.3	204.6	206.3	203.0
29	Coyote Springs 2	148.7	163.0	170.2	161.6	99.6	43.8	58.0	166.1	189.7	185.0	177.3	185.0	185.4
30	Kettle Falls	34.9	42.4	44.4	43.8	10.5	0.0	0.0	46.0	46.4	46.4	46.4	46.4	46.4
31	Kettle Falls CT	0.1	0.0	0.1	0.0	0.1	0.3	0.1	0.5	0.4	0.0	0.0	0.0	0.0
32	Lancaster	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
33	Northeast	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.0	0.0	0.0	0.0
34	Rathdrum	0.3	0.0	0.0	0.0	0.0	0.3	0.0	1.8	1.9	0.0	0.0	0.0	0.0
35	*TOTAL*	*374.7*	*409.1*	*421.0*	*410.0*	*300.0*	*166.3*	*188.3*	*418.7*	*445.2*	*437.7*	*428.3*	*437.7*	*434.7*
36														
37	*RESOURCE TOTAL*	*927.9*	*919.6*	*951.7*	*886.3*	*932.8*	*1,086.7*	*1,144.4*	*1,096.5*	*844.4*	*759.3*	*752.5*	*814.7*	*946.5*
38														
39	**Contracts**													
40	Black Creek	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.4	0.0	0.0
41	DOPD	3.7	2.4	2.4	3.3	4.8	6.7	7.3	5.3	3.8	2.0	2.4	2.0	1.8
42	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
43	Can Ent Return	(3.9)	(3.5)	(3.6)	(3.7)	(3.6)	(3.5)	(3.6)	(4.2)	(4.0)	(4.1)	(4.2)	(4.0)	(4.2)
44	Grant County	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
45	Clark Fork LLC	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.2	0.1	0.1	0.0	0.1	0.1
46	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
47	Grant Displacement	22.2	17.4	17.6	17.7	26.2	31.8	31.6	27.6	19.7	19.0	18.7	19.3	19.2
48	Stimson Lumber	4.2	4.2	4.4	4.5	4.3	4.0	4.0	4.0	4.4	4.3	4.0	4.5	4.0
49	Jim Ford Creek	0.4	0.6	0.8	1.2	1.0	0.6	0.3	0.0	0.0	0.0	0.0	0.2	0.4
50	John Day Creek	0.2	0.1	0.0	0.1	0.1	0.4	0.6	0.4	0.3	0.2	0.2	0.1	0.1
51	Meyers Falls	1.0	1.0	1.2	1.4	1.4	1.4	1.3	0.7	0.3	0.4	0.6	0.9	0.9
52	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)
53	Colstrip Start Energy	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
54	PGE CapExch	0.1	2.4	0.0	(2.8)	(0.4)	1.2	0.0	(0.8)	0.8	(0.4)	0.4	1.7	(0.8)
55	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
56	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
57	Wind Contract	8.4	8.6	7.4	10.0	9.1	8.5	10.4	8.3	8.3	7.2	7.8	8.3	6.3
58	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
59	Sheep Creek	0.8	0.4	0.6	1.1	1.5	1.6	1.6	1.0	0.3	0.2	0.3	0.5	0.4
60	Upriver	6.1	8.3	9.0	10.4	10.3	9.8	7.8	2.0	(1.2)	0.9	3.2	5.4	8.0
61	WNP-3	43.8	106.6	106.6	52.6	52.6	0.0	0.0	0.0	0.0	0.0	0.0	106.6	106.6
62	ST Purchases	51.3	0.0	0.0	0.0	0.0	0.0	0.0	114.5	114.0	114.4	89.5	88.9	89.5
63	ST Sales	(17.1)	0.0	0.0	0.0	0.0	0.0	0.0	(54.0)	(53.0)	(53.9)	(14.5)	(13.9)	(14.5)
64	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
65	Thompson River Co-Gen	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
66	*TOTAL*	*214.0*	*240.8*	*238.9*	*188.1*	*199.8*	*155.2*	*153.7*	*197.3*	*186.1*	*182.5*	*205.1*	*312.6*	*310.3*
67														
68	**Market Transactions**													
69	Market Purchases	83.7	156.8	122.2	93.3	61.2	15.5	15.5	31.6	113.3	90.4	121.3	95.4	89.5
70	Market Sales	(141.8)	(49.6)	(60.1)	(109.8)	(161.1)	(263.9)	(347.0)	(267.1)	(64.0)	(83.8)	(74.3)	(118.3)	(99.1)
71	*TOTAL*	*(58.0)*	*107.3*	*62.1*	*(16.5)*	*(99.9)*	*(248.4)*	*(331.5)*	*(235.5)*	*49.3*	*6.6*	*47.1*	*(22.9)*	*(9.5)*
72														
73	*System Load*	*1,083.9*	*1,267.7*	*1,252.7*	*1,057.9*	*1,032.7*	*993.4*	*966.6*	*1,058.3*	*1,079.8*	*948.4*	*1,004.7*	*1,104.4*	*1,247.3*

Exhibit No. 5
Case No. AVU-E-09-01
C. Kalich, Avista
Schedule 2, p. 2 of 3

Dispatch Model Proforma Generation (GWh)

#		Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1		**Ann**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2	**Hydro Projects**													
3	Clark Fork	2,854.5	183.0	191.5	175.7	264.4	482.5	490.5	335.4	181.8	120.1	104.8	119.7	205.2
4	Cabinet Gorge	1,097.6	74.7	79.3	73.1	107.1	168.4	164.4	132.5	74.4	48.9	43.2	49.1	82.8
5	Noxon Rapids	1,756.9	108.3	112.2	102.6	157.3	314.1	326.1	202.9	107.4	71.2	61.6	70.6	122.4
6	***TOTAL***	***2,854.5***	***183.0***	***191.5***	***175.7***	***264.4***	***482.5***	***490.5***	***335.4***	***181.8***	***120.1***	***104.8***	***119.7***	***205.2***
7														
8	Spokane River	1,100.3	103.0	96.4	118.1	121.7	125.0	112.0	73.5	40.9	55.7	71.3	85.7	97.0
9	Little Falls	205.4	20.4	18.7	22.7	23.3	24.0	21.3	13.0	7.2	9.3	12.1	15.4	17.9
10	Long Lake	514.2	49.4	45.1	56.1	59.6	62.0	53.8	32.7	18.9	23.9	30.4	38.0	44.3
11	Monroe Street	102.3	8.8	8.5	10.0	9.8	10.1	9.5	7.9	4.4	6.7	8.3	8.8	9.4
12	Nine Mile	116.8	10.2	10.4	12.4	12.8	12.4	11.7	8.3	4.3	6.0	8.1	9.5	10.8
13	Post Falls	86.0	7.7	7.7	10.0	9.9	10.0	9.3	5.3	2.0	3.8	5.4	7.2	7.7
14	Upper Falls	75.5	6.5	6.1	6.9	6.4	6.5	6.5	6.3	4.0	5.9	6.9	6.7	7.0
15	***TOTAL***	***1,100.3***	***103.0***	***96.4***	***118.1***	***121.7***	***125.0***	***112.0***	***73.5***	***40.9***	***55.7***	***71.3***	***85.7***	***97.0***
16														
17	Mid-Columbia- Contracts	890.9	93.8	68.7	60.6	69.5	77.4	85.9	95.4	74.3	55.7	65.1	66.0	78.5
18	Priest Rapids	168.6	22.7	17.0	14.2	12.6	9.5	13.3	10.7	10.4	8.9	10.3	17.7	21.1
19	Rocky Reach	178.1	19.2	13.3	12.0	15.7	16.7	19.1	18.7	16.0	10.1	11.6	11.9	14.0
20	Wanapum	241.3	20.4	15.7	14.0	16.5	19.9	21.5	34.8	20.6	19.5	23.1	16.0	19.4
21	Wells	303.0	31.5	22.8	20.4	24.6	31.3	32.0	31.2	27.3	17.2	20.0	20.5	24.0
22	***TOTAL***	***890.9***	***93.8***	***68.7***	***60.6***	***69.5***	***77.4***	***85.9***	***95.4***	***74.3***	***55.7***	***65.1***	***66.0***	***78.5***
23														
24	***TOTAL***	***4,845.8***	***379.8***	***356.6***	***354.4***	***455.6***	***684.8***	***688.4***	***504.3***	***297.0***	***231.5***	***241.2***	***271.4***	***380.8***
25														
26	**Thermals**													
27	Boulder Park	0.5	0.0	0.0	0.0	0.0	0.1	0.0	0.2	0.2	0.0	0.0	0.0	0.0
28	Colstrip	1,668.7	151.5	138.6	152.2	136.7	90.6	93.7	151.7	153.5	148.5	152.2	148.5	151.0
29	Coyote Springs 2	1,302.9	121.3	114.4	120.2	71.7	32.6	41.8	123.5	141.1	133.2	131.9	133.2	137.9
30	Kettle Falls	306.1	31.6	29.8	32.6	7.5	0.0	0.0	34.2	34.5	33.4	34.5	33.4	34.5
31	Kettle Falls CT	1.1	0.0	0.1	0.0	0.1	0.2	0.1	0.4	0.3	0.0	0.0	0.0	0.0
32	Lancaster	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
33	Northeast	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0
34	Rathdrum	3.0	0.0	0.0	0.0	0.0	0.2	0.0	1.3	1.4	0.0	0.0	0.0	0.0
35	***TOTAL***	***3,282.8***	***304.4***	***282.9***	***305.0***	***216.0***	***123.7***	***135.6***	***311.5***	***331.3***	***315.2***	***318.7***	***315.2***	***323.4***
36														
37	***RESOURCE TOTAL***	***8,128.6***	***684.2***	***639.5***	***659.4***	***671.6***	***808.5***	***824.0***	***815.8***	***628.2***	***546.7***	***559.9***	***586.6***	***704.2***
38														
39	**Contracts**													
40	Black Creek	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	0.0	0.0
41	DOPD	32.3	1.8	1.6	2.4	3.5	5.0	5.3	3.9	2.8	1.5	1.8	1.4	1.4
42	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
43	Can Ent Return	(33.8)	(2.6)	(2.4)	(2.7)	(2.6)	(2.6)	(2.6)	(3.1)	(3.0)	(3.0)	(3.1)	(2.9)	(3.1)
44	Grant County	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
45	Clark Fork LLC	1.2	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.1
46	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
47	Grant Displacement	194.2	13.0	11.8	13.1	18.8	23.7	22.8	20.5	14.6	13.7	13.9	13.9	14.3
48	Stimson Lumber	37.0	3.1	2.9	3.4	3.1	3.0	2.9	3.0	3.3	3.1	3.0	3.2	3.0
49	Jim Ford Creek	3.7	0.4	0.5	0.9	0.8	0.4	0.2	0.0	0.0	0.0	0.0	0.1	0.3
50	John Day Creek	1.9	0.1	0.0	0.1	0.1	0.3	0.4	0.3	0.2	0.1	0.1	0.1	0.1
51	Meyers Falls	8.4	0.7	0.8	1.0	1.0	1.0	0.9	0.5	0.2	0.3	0.5	0.6	0.7
52	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)
53	Colstrip Start Energy	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
54	PGE CapExch	0.9	1.8	0.0	(2.1)	(0.3)	0.9	0.0	(0.6)	0.6	(0.3)	0.3	1.2	(0.6)
55	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
56	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
57	Wind Contract	73.2	6.4	5.0	7.5	6.6	6.3	7.5	6.2	6.2	5.2	5.8	6.0	4.7
58	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
59	Sheep Creek	6.9	0.3	0.4	0.8	1.1	1.2	1.1	0.7	0.2	0.2	0.2	0.3	0.3
60	Upriver	53.8	6.2	6.1	7.8	7.4	7.3	5.6	1.5	(0.9)	0.6	2.4	3.9	6.0
61	WNP-3	384.0	79.3	71.6	39.1	37.9	0.0	0.0	0.0	0.0	0.0	0.0	76.7	79.3
62	ST Purchases	449.6	0.0	0.0	0.0	0.0	0.0	0.0	85.2	84.8	82.4	66.6	64.0	66.6
63	ST Sales	(150.0)	0.0	0.0	0.0	0.0	0.0	0.0	(40.2)	(39.4)	(38.8)	(10.8)	(10.0)	(10.8)
64	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
65	Thompson River Co-Gen	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
66	***TOTAL***	***1,874.7***	***179.1***	***160.5***	***139.9***	***143.9***	***115.4***	***110.7***	***146.8***	***138.4***	***131.4***	***152.6***	***225.1***	***230.8***
67														
68	**Market Transactions**													
69	Market Purchases	733.4	116.7	82.1	69.4	44.1	11.5	11.1	23.5	84.3	65.1	90.3	68.7	66.6
70	Market Sales	(1,241.8)	(36.9)	(40.4)	(81.7)	(116.0)	(196.4)	(249.8)	(198.7)	(47.6)	(60.3)	(55.2)	(85.2)	(73.7)
71	***TOTAL***	***(508.4)***	***79.8***	***41.8***	***(12.3)***	***(71.9)***	***(184.8)***	***(238.7)***	***(175.2)***	***36.7***	***4.8***	***35.0***	***(16.5)***	***(7.1)***
72														
73	***SYSTEM LOAD***	***9,494.9***	***943.1***	***841.8***	***787.1***	***743.5***	***739.1***	***696.0***	***787.4***	***803.4***	***682.9***	***747.5***	***795.1***	***928.0***