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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-G-10-01 DIRECT TESTIMONY OF KEVIN J. CHRISTIE

FOR AVISTA CORPORATION

(NATURAL GAS)

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corp.

A. My name is Kevin Christie and I am employed as Director of Gas Supply of Avista Utilities (Avista or Company), at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you please describe your education and business experience?

A. Yes. I graduated from Washington State University with a Bachelors Degree in Business Administration with an accounting emphasis. I have also attended the University of Idaho Utility Executive Course.

I joined the Company in 2005 as the Manager of Natural Gas Planning. In 2007, I was appointed the Director of Gas Supply. Prior to joining Avista, I was employed by Gas Transmission Northwest (GTN). I was employed by GTN from 2001 to 2005 and was the Director of Pipeline Marketing and Development from 2003 to 2005 and the Director of Pricing and Business Analysis from 2001 to 2003. From 2000 to 2001, I was employed by PG&E Corporation (PG&E) as the Manager of Finance and Assistant to the SVP, Treasurer and CFO. Before joining PG&E, I was employed by Pacific Gas Transmission Company (PGT) from 1994 to 2000. While at PGT, I held several positions including Manager, Pricing and Business Analysis, Senior Business Analyst, Senior Pricing Planner, Director of Regulatory Affairs, Project Manager – Rates and Regulatory Affairs, Senior Regulatory Analyst, Regulatory Analyst, and Revenue Accountant. From 1990 to 1994, I was employed by Chevron USA as a Lease Revenue Accountant.

Q. Mr. Christie, what is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe additional Jackson Prairie (JP) natural gas storage that the utility will receive to serve customers beginning May 1, 2011. I will also describe the allocation of this additional storage, and the associated costs, to the three jurisdictions that the Company serves.

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 11, which contains cost and pricing information relative to Jackson Prairie Storage (Schedule 1) and a copy of the Company's 2009 Natural Gas Integrated Resource Plan (Schedule 2).

II. HISTORY OF JACKSON PRAIRIE STORAGE FACILITY

Q. Could you please describe Avista's involvement with the Jackson Prairie gas storage facility?

A. Yes. Avista is one of the three original developers of the underground storage facility at Jackson Prairie, which is located near Chehalis, Washington. Although there have been corporate changes due to mergers, acquisitions and name changes, Avista, Puget Sound Energy (PSE) and Northwest Pipeline each hold a one-third share (equal, undivided interest) of this underground gas storage facility through a joint ownership agreement. Development of the facility began in the 1960's and the project first went into service in the early 1970's.

Q. What type of storage facility is Jackson Prairie?

A. Jackson Prairie is an underground aquifer storage facility. Storage and the associated withdrawal and injection capability has been created by a combination of wells, gathering pipelines, compression and dehydration equipment, and the removal and disposal of aquifer water.

Q. Please describe the present level of storage that Avista owns at Jackson Prairie.

A. At the present time, the Company holds a total 5,497,112 dekatherms (Dth) of seasonal capacity. This seasonal capacity comes with a withdrawal capability of 294,667 Dth per day (deliverability). As described below, on May 1, 2011, the utility will receive an additional 3,030,887 Dth of seasonal capacity and an additional 104,000 Dth of daily deliverability.

Q. Could you please describe what is meant by "capacity" and "deliverability"?

A. Yes. Capacity is the total amount of gas that the facility holds and represents the volume of gas that can be made available for injection and withdrawal by the owner. This capacity is typically referred to as "working" gas. Working gas is different from "cushion" gas which is also stored in the facility. Cushion gas must physically remain in the facility at all times to ensure the deliverability of the working gas and, therefore, cannot be withdrawn on a seasonal basis. Cushion gas provides the field pressure necessary to allow the withdrawal of working gas. Capacity, as used herein, refers to the working gas portion of Jackson Prairie. Deliverability, as used herein, is the maximum amount of gas that can be withdrawn from the facility on a daily basis.

Q. Can cushion gas be withdrawn from the facility?

A. As stated above, cushion gas must remain in the facility in order to withdraw working gas. However, when the field is abandoned, there will be residual cushion gas in the field that will not be recoverable due to economics and physical constraints. Therefore, a portion of cushion gas is estimated to be <u>non-recoverable</u> from the facility and that portion is depreciated over the estimated life of the facility (account 352.3-Nonrecoverable natural gas). The <u>recoverable</u> portion of cushion gas remains at its original cost over the life of the facility (account 117.1-Gas stored-base gas). Both accounts are included in the Company's rate base (Company witness Ms. Andrews discusses the proposed accounting treatment).

Q. Could you please describe Avista's share of the expansions that have occurred at the facility since 1999?

A. Yes. In 1999, the owners agreed to both a capacity and deliverability expansion of the facility (FERC Certificate in CP98-250-000). Avista's allocated annual share of the expansion capacity was 1,066,667 Dth and 104,000 Dth per day of deliverability. Based on the Company's Integrated Resource Plan (IRP) at the time, Avista's share of the expansion capacity would have provided storage capacity in excess of what was needed to serve Avista's near-term customer requirements. While additional storage capacity was not called for in the IRP in the near-term, it was determined that the expansion capacity would be needed to meet future growth in later years. In order to better align the expansion costs and the future need for this resource, the increased capacity and deliverability were temporarily assigned to Avista Energy. One alternative was to allow PSE or Northwest Pipeline to pay for the expansion, which would have reduced Avista's one-third ownership share in the facility. However, the Company believed that it was very important to preserve its one-third ownership share, in order to have equal voting rights in all matters related to the facility. Assigning the expansion to Avista Energy allowed the

Company to preserve its ownership share long-term, but avoid the cost of the expansion for a number of years. Avista Energy provided the capital necessary to develop the expansion in exchange for the rights to utilize the expanded portion of the storage facility for a minimum period of ten years.

Beginning in 2002, another capacity expansion was initiated at the facility (FERC Certificate in CP02-384-000). This capacity expansion was a multi-year expansion that was completed in phases with the last phase placed into service during 2008. Similar to the 1999 expansion, this expansion was temporarily assigned to Avista Energy; Avista Energy paid the capital required for this expansion in exchange for the rights to utilize that portion of the facility for a period of time. The temporary assignment to Avista Energy from this expansion was for 1,964,220 Dth of seasonal capacity.

Effective July 1, 2007, Avista Energy's business and contracts were sold to Shell Energy North America (Shell). The sale to Shell included the temporary contractual assignment of both expansions for a total of 3,030,887 Dth of seasonal storage expansion capacity and 104,000 Dth of daily deliverability through April 30, 2011. On May 1, 2011, the expansion capacity and deliverability will revert to Avista Utilities at net book value. The net book value of this storage is $11,628,892[1] (system), as shown on Page 2, line 3 in Schedule No. 1 of Exhibit No. 11. Company witness Ms. Andrews discusses further the adjustment included in the Company's filing.

Avista Utilities covered the costs associated with the remaining phases (after July 1, 2007 through October 31, 2008), of the 2002 capacity expansion, i.e., the utility funded the remaining capital requirements necessary to complete the remaining phases. Upon completion of the expansion, all costs associated with these remaining phases were assigned to the Company's Oregon customers. As a result, Oregon customers received 262,446 Dth of seasonal storage capacity (no daily deliverability).

In 2007, under FERC Docket CP06-412-000, a deliverability expansion (no additional capacity) was initiated at the facility and, by late 2008, that expansion was completed. Related to the assignment of capacity to Oregon customers described above, Oregon was allocated 25% of the volumes and costs associated with this deliverability expansion. This proportion was based on forecasted jurisdictional sales volumes for the Nov. 2008 – Oct. 2009 period. The Company's Washington and Idaho customers were allocated the remaining 75% of the volumes and costs associated with this expansion, and this

[1] The net book value of the storage transferred from Avista Energy to Avista Utilities is comprised of cushion gas of approximately $5.9 million and fixed assets/plant of approximately $5.7 million.

Commission approved recovery of those (Idaho allocated) costs in Order No. 30856 in Case No. AVU-G-09-01.

III. COST ALLOCATION AND RECOVERY OF JACKSON PRAIRIE

Q. How is the Company proposing to allocate the costs, by jurisdiction, associated with the additional (JP) capacity and deliverability that it will have available on May 1, 2011?

A. The allocation of this capacity and deliverability is proposed to be such that, when <u>all</u> JP expansion volumes and costs (added since 1999) described above are totaled, Washington/Idaho customers will receive 75% of the total and Oregon will receive 25% of the total, based on forecasted jurisdictional sales volumes for the Nov. 2008 - Oct. 2009 period. The allocation of these volumes and costs are shown in Page 2, Schedule 1 of Exhibit No. 11.

Q. Has the Company previously discussed this JP expansion allocation plan with representatives of the three Commission staffs?

A. Yes. This allocation plan was first discussed in person with Washington, Idaho and Oregon Commission staffs in early 2007, as well as in subsequent meetings. All three staffs indicated support of the allocation plan.

Q. Does the proposed allocation of the expansion

costs described above affect the allocation of JP volumes and costs the utility held prior to these expansions?

A. No. All JP volumes held by the Company prior to these expansions are dedicated to serve Washington and Idaho customers.

Q. What are the benefits of storage to Avista's customers?

A. Access to regionally located storage provides several benefits to Avista customers. It enables the Company to capture seasonal price spread, improves reliability of supply, increases operational flexibility, mitigates peak demand price spikes and provides numerous other economic benefits. The transfer of the storage back to the Company is reflected in Avista's 2009 Natural Gas Integrated Resource Plan (IRP) attached as Schedule 2 in Exhibit No. 11.

Q. Has the value of these benefits increased since the expansion capacity described above was first assigned to Avista Energy in 1999?

A. Yes. As further described below, with the increased volatility of natural gas prices and a more complex gas market, the market value of storage has increased markedly since that time.

Q. What is the estimated value of the seasonal price spread?

A. The seasonal price spread, in its simplest terms, is the difference in the price per Dth between what one could purchase gas for in the non-winter months versus what those same volumes would cost if purchased in the winter season. Storage allows for the capture of the potentially lower priced non-winter gas and the ability to use it during the potentially higher priced winter months. Sumas is the market hub that is the likely pricing point for natural gas injections and withdrawals into Northwest area storage. Page 1, Schedule 1 of Exhibit No. 11 shows the present monthly forward prices at Sumas over the next three years. These forward prices reflect the purchase price today for gas delivered during that future month. As shown, the average seasonal price spread over the next three years is $1.79 per Dth.

Q. Have you compared this estimated market value of $1.79 to an estimated annual revenue requirement (cost) associated with this incremental storage capacity?

A. Yes. The estimated revenue requirement cost is $0.54 per Dth, as shown on Page 2, (Line 7) Schedule 1 of Exhibit No. 11. Without even considering the other benefits associated with this incremental storage, this annual cost is well below the estimated market value of $1.79 per Dth.

Q. You also mentioned improved reliability of supply. Please explain.

A. The Company relies on monthly and longer-term seasonal, annual and multi-year contracts for supply to satisfy its projected average daily demand. For daily swings in demand, above and below average, the Company relies on a combination of storage and daily purchases and sales. In today's market, virtually all physical short-term purchases are done at market hubs like Sumas/Huntingdon. While these purchases are generally reliable, there is a risk of delivery failure either in supply availability or counterparty risk. There are a number of reasons why delivery risk can be problematic. First, using the Sumas/Huntingdon Hub as an example, gas may change hands (trade) numerous times between parties. The failure of one party in the chain relying on interruptible transportation or a less than secure supply source can result in supply loss on any given day. A second reason is that it takes just one scheduling error in the supply chain to result in a supply loss. And third, actual physical problems such as well freeze-offs or pipeline force majeure situations along the transportation path can also result in supply loss.

As an owner of the facility, Avista controls the Company's nominations both at the facility and on the pipeline. This ensures scheduling transactions without the inclusion of a third party, thus eliminating intermediate steps and the potential for error. This results in a more reliable process during pipeline entitlements. Access to storage provides the Company with more control and, therefore, more reliability of supply during these events.

Q. What operational benefits does storage provide?

A. Operationally, storage provides the flexibility to adjust supply either up or down during the actual day. Normally gas is scheduled one day in advance. Jackson Prairie storage allows Avista the flexibility to increase or decrease the supply several times during the actual gas day. This flexibility is critical to maintaining mandated tolerances on pipelines and allows for active supply management during pipeline entitlements and operational flow orders. This level of management reduces the likelihood of incurring pipeline penalties.

Q. Please explain what you mean by mitigation of peak demand price spikes.

A. As with most local distribution companies in the Northwest, Avista's demand is very temperature-sensitive. The result is that Avista is a "winter-peaking" utility. During severe cold weather events in its service territory or cold events in large market centers outside of the Northwest, natural gas prices may increase dramatically. To the extent that the Company can rely on storage withdrawals, the purchase of potentially higher-priced spot gas may be avoided during these events. As previously mentioned, storage also provides the ability to adjust volumes, even after the original nomination schedule. This eliminates the need to purchase peaking contracts from suppliers. Peaking supply is one of the most expensive resources to acquire. The greater the operational flexibility in a supply contract, the more expensive the product. The avoided cost of procuring a peaking resource with the flexibility characteristics of storage is a significant cost savings/avoidance. This benefit is in addition to the typical seasonal price spread explained earlier. The addition of storage deliverability further increases Avista's ability to manage these price spikes and avoid supplier costs.

Q. Are there other economic benefits related to JP?

A. As previously mentioned, Sumas is the most likely pricing point to Jackson Prairie. Sumas pricing is very volatile during winter weather events. Storage provides an avoided cost of contracting for supply at Sumas, which can be the most expensive supply point available to Northwest utilities. Given the geographical weather diversity across the Northwest, JP storage provides opportunities to benefit from Sumas price spikes during cold events west of the Cascades by selling natural gas into that market when Avista customers may not otherwise be experiencing high supply requirements.

Q. Does Avista have pipeline transportation capacity available to provide delivery of these incremental storage volumes?

A. Yes. Existing transportation contracts from Sumas can be used to redeliver storage volumes. The Company will avoid a portion of winter purchases at Sumas and utilize storage as a substitute for this supply. Therefore, the same transportation contracts that are utilized now for physical supply purchases can be used for the delivery of storage gas.

Q. How much of Avista's annual average demand and average winter demand for its Idaho customers can be served by storage after May 1, 2011?

A. Approximately 30% of Avista's average annual demand and 44% of average winter demand can be served by JP storage after May 1, 2011.

Q. Company witness Andrews mentions an adjustment in her testimony associated with JP working gas inventory. Can you describe how that adjustment was determined?

A. Yes. The adjustment reflects the estimated cost of the average JP working gas inventory during the calendar year ending September 2011, less the actual average inventory cost during the test year (2009). This working gas inventory is considered rate base as there will be an average level of working gas that will exist in the facility for the life of the project, and the revenue requirement reflects the authorized rate of return on that rate base. The average level (working gas volumes) of JP inventory will increase with the additional capacity the Company will receive May 1, 2011. Therefore, the inventory level will reflect an adjustment related to this additional capacity as well as year-over-year changes in the cost of gas injected into storage.

The Company uses a "synthetic" or forecasted injection/withdrawal schedule to determine the average inventory level during the year. This synthetic schedule is based on monthly forecasted injection and withdrawal volumes during the year, resulting in an estimated monthly inventory level. Injections into storage are priced at the "forward" gas price for that month, i.e., the price at which gas can be purchased at today for delivery in a future month. In estimating the cost of injections during the pro forma period, the Company used a 60-day average of forward prices from November 5, 2009 to February 1, 2010. An average cost of inventory is calculated at the beginning of each month and withdrawal volumes are priced at the average cost of inventory for that month. Based on the estimated average inventory balance during the pro forma period compared to the actual average balance during 2009, the increase to rate base is $2,396,049.

Q. Is this methodology consistent with the JP inventory adjustment used in the Company's last general rate case?

A. Yes.

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

A. Yes it does.

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FOR AVISTA CORPORATION

(NATURAL GAS)

Forward Sumas Summer - Winter Differentials

Prices are an average of the forward prices for the month from January 2009 through February 2010 at Sumas

	a	b	c	d	e	f	g	h	i	j	k
			Summer Price 2010	Winter Price 2010-2011	Difference 2010-2011	Summer Price 2011	Winter Price 2011-2012	Difference 2011-2012	Summer Price 2012	Winter Price 2012-2013	Difference 2012-2013
1	January-09		$ 5.99	$ 7.95	$ (1.96)	$ 6.35	$ 8.21	$ (1.87)	$ 6.40	$ 8.23	$ (1.84)
2	February-09		$ 5.36	$ 7.30	$ (1.94)	$ 6.04	$ 7.92	$ (1.88)	$ 6.19	$ 7.94	$ (1.75)
3	March-09		$ 4.90	$ 6.77	$ (1.87)	$ 5.48	$ 7.36	$ (1.87)	$ 5.67	$ 7.42	$ (1.76)
4	April-09		$ 4.95	$ 6.92	$ (1.97)	$ 5.80	$ 7.54	$ (1.74)	$ 6.06	$ 7.83	$ (1.77)
5	May-09		$ 5.25	$ 7.23	$ (1.98)	$ 6.07	$ 7.81	$ (1.73)	$ 6.27	$ 8.03	$ (1.76)
6	June-09		$ 5.31	$ 7.32	$ (2.01)	$ 6.19	$ 7.92	$ (1.73)	$ 6.42	$ 8.18	$ (1.76)
7	July-09		$ 4.85	$ 6.85	$ (2.00)	$ 5.76	$ 7.47	$ (1.71)	$ 5.97	$ 7.70	$ (1.73)
8	August-09		$ 4.95	$ 7.02	$ (2.07)	$ 5.82	$ 7.51	$ (1.70)	$ 5.96	$ 7.69	$ (1.73)
9	September-09		$ 4.98	$ 7.10	$ (2.12)	$ 5.71	$ 7.43	$ (1.72)	$ 5.91	$ 7.61	$ (1.70)
10	October-09		$ 5.53	$ 7.49	$ (1.96)	$ 6.06	$ 7.75	$ (1.69)	$ 6.25	$ 7.96	$ (1.71)
11	November-09		$ 4.87	$ 7.11	$ (2.25)	$ 5.69	$ 7.34	$ (1.64)	$ 5.89	$ 7.55	$ (1.66)
12	December-09		$ 5.26	$ 7.35	$ (2.09)	$ 5.82	$ 7.46	$ (1.64)	$ 6.00	$ 7.60	$ (1.61)
13	January-10		$ 5.32	$ 7.05	$ (1.73)	$ 5.67	$ 7.21	$ (1.54)	$ 5.85	$ 7.36	$ (1.52)
14	February-10		$ 5.07	$ 6.71	$ (1.65)	$ 5.53	$ 6.99	$ (1.45)	$ 5.69	$ 7.15	$ (1.46)
15											
16	Average				$ (1.97)			$ (1.71)			$ (1.70)
17	Three Year Average	$ (1.79)									

1/ Summer prices are the average of May, June, and July.
2/ Winter prices are the average of December, January, and February.

Exhibit No. 11
Case No. AVU-G-10-01
K. Christie, Avista
Schedule 1, P. 1 of 2

Avista Corporation
Company Owned - Jackson Prairie Storage Summary

a	b Total Capacity	c Total Deliverability	d Total Cost as Filed		e WA/ID Capacity Allocation	f Oregon Capacity Allocation	g WA/ID Deliverability Allocation	h Oregon Deliverability Allocation		i WA/ID Capacity (b*e)	j WA/ID Deliverabilit y (c*g)	k Cost Assigned (d*e)	l Oregon Capacity (b*f)	m Oregon Deliverability (c*h)	n Cost Assigned (d*f)
1 '02 Capacity Expansion - July '07 - Oct '08 1/	262,446	-	$ 976,027	6/	0%	100%	0%	0%	9/	-	-	$ -	262,446	-	$ 976,027
2 '08 Deliverability Expansion - 11/08 2/	-	104,000	$ 14,673,253	7/	75%	25%	75%	25%	9/	-	78,000	$ 10,861,221	-	26,000	$ 3,812,032
3 '99 Capacity & Deliverability & '02 Capacity Expansion from Shell/AE - 4/11 3/	3,030,901	104,000	$ 11,628,892	8/			75%	25%	9/	2,470,010	78,000	$ 9,597,409	560,891	26,000	$ 2,031,485
4 Total Capacity/Deliverability/Costs	3,293,347	208,000	$ 27,278,172							2,470,010	156,000	$ 20,458,630	823,337	52,000	$ 6,819,544
5															
6 Revenue Requirement 4/												$ 1,343,637			
7 Capacity Cost per Dth 5/												0.54			
8															
9															
10 Ending Capacity and Deliverability Percent 9/										75.00%	75.00%	75.00%	25.00%	25.00%	25.00%

1/ Capacity expansion began in 2002 and was paid for by Avista Energy. After the sale of Avista Energy to Shell in July 2007 Avista Utilities took over the remaining costs and associated capacity.
2/ Avista Utilities participated in the deliverability expansion which was completed in October 2008.
3/ Capacity and deliverability expansion owned by Avista Energy and subsequently released to Shell at the time of the Avista Energy sale.
4/ The estimated annual revenue requirement is based on 14% of the allocated incremental capital costs of $9,597,409.
5/ The capacity cost per Dth is based on the annual revenue requirement divided by the incremental capacity of 2,470,010.
6/ The cost of wells and cushion gas (174,964 Dth) injected at an average actual price of $5.58. This is the balance as of 12/31/2009
7/ Actual cost of the expansion as of 12/31/2009. The project was completed and placed in service 10/31/2008.
8/ The estimated book value on Avista Energy's books @ 4/30/2011 as of 02/28/2010.

Capacity $ 5,886,727 Deliverability $ 5,742,165 Total $ 11,628,892

9/ The capacity and deliverability were to be allocated so that 75% to Washington and Idaho and 25% to Oregon after all capacity and deliverability expansions were completed. (Line 6 divided by total capacity in line 4).
This split was based on estimated demand derived within SENDOUT®.

Exhibit No. 11
Case No. AVU-G-10-01
K. Christie, Avista
Schedule 1, P. 2 of 2

Natural Gas Integrated Resource Plan (IRP)

Compact Disc Exhibit

Also Available At

http://www.avistautilities.com/inside/resources/irp/Pages/default.aspx

Exhibit No. 11
Case No. AVU-G-10-01
K. Christie, Avista
Schedule 2, P. 1 of 1