

Exh. DCG-13
Dockets UE-190334, UG-190335,
and UE-190222
Witness: David C. Gomez

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

**AVISTA CORPORATION, d/b/a
AVISTA UTILITIES,**

Respondent.

**DOCKETS UE-190334, UG-190335,
and UE-190222 (*Consolidated*)**

**EXHIBIT TO
TESTIMONY OF**

David C. Gomez

**STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION**

*In the Matter of Avista Corp.,
Energy Recovery Mechanism (ERM)
Annual Filing to Review Deferrals for Calendar Year 2004,
Docket No. UE-050492, Storro, Exh. RLS-1T*

October 3, 2019

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STATE OF WASH.
UTIL. AND TRANSP.
COMMISSION

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. _____

DIRECT TESTIMONY OF

RICHARD L. STORRO

REPRESENTING AVISTA CORPORATION

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I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Richard L. Storro. My business address is 1411 East Mission Avenue, Spokane, Washington, and I am employed by the Company as the Director of Power Supply.

Q. What is your educational background?

A. I participated in a program with the College of Idaho and the University of Idaho, where upon completion I received a Bachelor of Science degree in physics from the College of Idaho and a Bachelor of Science degree in electrical engineering from the University of Idaho, both in 1973.

Q. How long have you been employed by the Company?

A. I started working for Avista in 1973 as a distribution engineer. I have worked in various engineering positions, and have held management positions in line and gas operations, system operations, hydro production and construction, and transmission. I joined the Energy Resources Department as a Power Marketer in 1997 and became Director of Power Supply in 2001. My primary responsibilities involve the oversight of both the short-term and long-term planning and acquisition of power supply resources for the Company.

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

A. My testimony will provide an overview of the history of the ERM and provide a summary of the factors contributing to the power cost deferrals during the 2004 calendar year review period. I provide an overview of the documentation the Company has provided in workpapers, which the Company had agreed to provide in the ERM Settlement Stipulation

1 approved and adopted in Docket No. UE-030751. I will also discuss the transformer outage at
2 Coyote Springs 2 during 2004 and how the lost margin from the plant being out of service in
3 2004 will likely be much less than the margin from the second half of Coyote Springs 2 that will
4 flow through the ERM to the customer's benefit in 2005.

5 **Q. Are other witnesses sponsoring testimony on behalf of Avista?**

6 A. Yes. Mr. William Johnson will provide testimony regarding the calculation of the
7 monthly power cost deferrals. Mr. Ron Mckenzie will provide testimony concerning the monthly
8 deferral entries and deferral balance.

9 **II. OVERVIEW**

10 **Q. Would you please explain the history of the ERM and the annual filing**
11 **requirement?**

12 A. Yes. The ERM was approved by the Commission's Fifth Supplemental Order in
13 Docket No. UE-011595 dated June 18, 2002, and was implemented on July 1, 2002. That Order
14 approved and adopted a Settlement Stipulation (UE-011595 Stipulation) that explained the
15 mechanism and reporting requirements. Pursuant to the UE-011595 Stipulation, the Company is
16 to make an annual filing on or before April 1st of each year to provide the opportunity for the
17 Commission Staff and interested parties to review the prudence of the ERM deferral entries for
18 the prior calendar year. Interested parties are to be provided a 90-day review period ending June
19 30th of each year to review the deferral information. The 90-day review period may be extended
20 by agreement of the parties participating in the review, or by Commission order.

21 Avista's first Annual ERM Filing to review deferrals covered the six-month period of
22 July 1, 2002 through December 31, 2002. In its Order No. 5 issued February 3, 2004 in Docket

1 No. UE-030751 the Commission approved and adopted a Settlement Stipulation (UE-030751
2 Stipulation) that resolved the issues related to the first review period.

3 Avista's Annual ERM Filing to review deferrals for calendar year 2003 was addressed by
4 the Commission's Order No. 1 dated August 11, 2004 in Docket No. UE-040611. In that order
5 the Commission found that the filing met the requirements of Docket No. UE-011595 and UE-
6 030751, and that the power costs deferrals for 2003 were prudent.

7 **Q. What period is covered by this ERM filing?**

8 A. This ERM filing covers the period January 1, 2004 through December 31, 2004.

9 **Q. What were the changes in power costs, the amounts deferred, and the**
10 **amounts absorbed by the Company during 2004?**

11 A. During 2004 actual net power costs exceeded authorized net power costs for the
12 Washington jurisdiction by \$20,663,573. Of that amount \$10,497,216 was deferred, and the
13 remaining \$10,166,357 was absorbed by the Company. Under the ERM, the first \$9.0 million of
14 net power supply costs above or below the authorized level is absorbed by the Company. Ninety
15 percent of power costs beyond the \$9.0 million band are deferred for the opportunity for later
16 recover. The remaining 10% is also absorbed by the Company. Carrying costs amounted to
17 \$280,482, resulting in a total deferral balance for the 2004 calendar year of \$10,777,698.

18 **III. SUMMARY OF DEFERRED POWER SUPPLY COSTS**

19 **Q. Would you please summarize the factors driving power supply expenses**
20 **during the review period?**

21 A. Yes. Power supply expenses were higher than authorized due primarily to lower
22 hydro generation, losses on the sale of natural gas that was originally purchased for thermal

1 generation, the transformer failure at Coyote Spring 2 that caused the plant to be out of service
2 from January 16 through September 6, 2004 and the expiration of a profitable wholesale contract.

3 Hydro generation was approximately 23 aMW below the authorized level, which
4 accounts for approximately \$5.8 million (Washington allocation) of \$20.7 million increased
5 expense. This increased expense attributed to lower hydro generation is based on an average
6 purchase and sale price for power during the review period of \$41.93/MWh, which was above
7 the authorized level of \$32.17/MWh.

8 The loss on the sale of natural gas that was purchased for generation and later sold instead
9 of burned was approximately \$5.7 million (Washington allocation). It should be noted that
10 most of those losses were attributable to fixed price gas contracts that were purchased during the
11 energy crises in early 2001. The last of those contracts ended October 31, 2004. These contracts
12 and the associated increased costs were addressed by the parties in developing the prior
13 Settlement in Docket No. UE-011595, which was approved by the Commission in June 2002.

14 Another factor contributing to higher than authorized power supply net expense in 2004
15 was the outage at CS2 due to a transformer failure. Lost operating margin at CS2 for the period
16 January 16 though September 6, 2004 is estimated to be approximately \$1.9 million (Washington
17 allocation).

18 Avista's long-term sale to PacifiCorp, which lowered authorized net expense by
19 approximately \$2.6 million (Washington allocation) ended September 2003, so that margin was
20 not there in 2004.

21 In addition, the Company' gas-fired projects generated less than the authorized level due
22 to the relatively low price of electricity compared to natural gas costs. The average market

1 implied heat rate (Dow Jones Mid C index divided by Platt's gas Daily Malin Midpoint) during
2 2004 was 7,947 Btu/kWh. This compares to the average market implied heat rate embedded in
3 the authorized proforma of 10,102 Btu/kWh. The lower market heat rate meant that market
4 economics favored purchasing electricity rather than generating electricity with natural gas and,
5 consequently, the Company's gas-fueled resources ran less than in the authorized proforma and
6 produced lower operating margins.

7 The Company's other thermal plants, Colstrip and Kettle Falls generated 4 average
8 megawatts below and 22 average megawatts above the authorized level, respectively.

9 Finally, the Company entered into three new long-term contracts during the review
10 period. In April 2004, the Company signed a 10-year agreement to purchase wind power. In
11 June 2004, the Company entered into an 8-year agreement to purchase power from the City of
12 Spokane's Upriver hydroelectric plant. In October 2004 the Company extended an agreement to
13 purchase power from the Black Creek hydroelectric facility. These contracts were provided as
14 confidential attachments to the monthly deferral reports.

15 **IV. COYOTE SPRINGS 2 TRANSFORMER OUTAGE**

16 **Q. Please further explain the transformer outage at the Coyote Springs 2 plant.**

17 A. On January 15, 2004, operating indicators at the Coyote Springs 2 project noted a
18 potential internal arcing problem in the plant generator step-up transformer (the main transformer
19 connecting the plant to the grid). Numerous tests were conducted and found that internal arcing
20 had in fact occurred, however the internal inspection found no visible cause. The manufacturer
21 (Alstom) determined that the only way to find the cause was to return the transformer to its repair
22 facility. The transformer was repaired and returned to the project site. As a result of the

1 transformer malfunction the plant was out of service from January 16, 2004 through September
2 6, 2004. The transformer and the CS2 plant returned to service on September 7, 2004. Since that
3 time the project has performed very well with an average equivalent availability factor of
4 99.33%.

5 **Q. Has the Company made an estimate of the lost margin due to the outage?**

6 A. Yes. The Company estimates that the margin that Coyote Springs 2 could have
7 produced during the period when the plant was not available was \$1,888,363 (Washington
8 allocation). Of this total, \$1,699,527 would have been deferred in the ERM (\$1,888, x 90%
9 customer share). This amount is less than one might expect, but as explained earlier, due to the
10 relatively low price of electricity compared to natural gas costs during 2004, the plant would not
11 have operated during a major portion of the time that the transformer was out of service.

12 **Q. Are there any offsets to the Coyote Springs 2 lost margin resulting from the**
13 **transformer outage?**

14 A. Yes. Avista acquired the second half of CS2 on January 20, 2005 and has been
15 operating the plant for the benefit of customers since that time. The operating margins from the
16 second half of the plant will flow through the ERM and lower 2005 deferrals. The addition of
17 the second half of CS2 was very timely given the very low hydro conditions expected for the
18 balance of the runoff period. Based on actual prices through March 17 and forward prices
19 through December 2005, it is anticipated that the second half of Coyote Springs 2 will produce
20 operating margins of \$5,741,293 (Washington allocation). Of this total, estimates show that
21 \$5,167,164 (\$5,741,293 x 90% customer share) will be flowed through the ERM and reduce
22 2005 deferrals after the dead band is full.

1 (provided for each gas and electric transaction, not including real-time and pre-schedule
2 transactions).

3 Position Reports: These daily reports provide a summary of monthly loads and resources over an
4 18-month forward period. Also included are forward hydroelectric generation estimates as well
5 as critical water generation variability. Fixed price natural gas quantities are also shown assigned
6 to the most economic available generation plant.

7 Long-Term Physical Electric Load & Resource Tabulation: For transactions with deliveries
8 extending greater than the 18-month period covered by the Position Report, the Company
9 includes this document to show the net average system position during the extended period. This
10 document also shows variability associated with an 80% confidence interval around the
11 combined variability of hydroelectric generation and variability of load.

12 Forward Market Electric and Natural Gas Price Curves: This daily data is maintained in
13 Nucleus, the Company's electronic energy transaction database record system.

14 Electric/Gas – Heat Rate Transaction Worksheet: For each natural gas transaction a worksheet is
15 prepared which summarizes the economics of the transaction using the forward electric and
16 natural gas prices available in the market at the time of the transaction, the most economic
17 available generator, and the resultant cost to generate electric power (provided as part of
18 Gas/Electric Transaction Record).

19 Price Quote Worksheet: Provides a record of the natural gas purchase or sales prices available
20 from several parties in the market at the time of a particular gas transaction. This record includes

1 price information at specific points of delivery (provided as part of Gas/Electric Transaction
2 Record).

3 Credit Report: Lists those counter-parties with which the Company is allowed to enter
4 into either purchase or sales transactions as determined by credit criteria set by the Company.

5 These documents are in addition to the detailed monthly reports, which are filed with the
6 Commission and provided to interested parties, as discussed by Mr. Mckenzie.

7 **Q. Does that conclude your pre-filed direct testimony?**

8 A. Yes.

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