

**Exhibit No. \_\_\_ (DCG-23)**  
**Dockets UE-150204/UG-150205**  
**Witness: David C. Gomez**

**BEFORE THE WASHINGTON  
UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION,**

**Complainant,**

**v.**

**AVISTA CORPORATION dba AVISTA  
UTILITIES,**

**Respondent.**

**DOCKETS UE-150204 and  
UG-150205**  
*(Consolidated)*

**EXHIBIT TO  
TESTIMONY OF**

**DAVID C. GOMEZ**

**STAFF OF  
WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION**

*Direct Testimony of Avista witness Scott J. Kinney Exhibit No. \_\_\_ (SJK-1T) in UE-140188 and  
UG-140189 (consolidated)  
(Provided on CD)*

**July 27, 2015**

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-14 \_\_\_\_\_

DIRECT TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

1 **I. INTRODUCTION**

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

3 A. My name is Scott J. Kinney. I am employed as the Director of Power Supply  
4 at Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington.

5 **Q. Would you briefly describe your educational and professional**  
6 **background?**

7 A. Yes. I graduated from Gonzaga University in 1991 with a B.S. in Electrical  
8 Engineering and I am a licensed Professional Engineer in the State of Washington. I joined  
9 the Company in 1999 after spending eight years with the Bonneville Power Administration.  
10 I have held several different positions at Avista in the Transmission Department, beginning  
11 as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations  
12 Department as a Supervisor and Support Engineer. In 2004, I was appointed as the Chief  
13 Engineer, System Operations and the Director of Transmission Operations in June 2008. I  
14 became the Director of Power Supply in January 2013, where my primary responsibilities  
15 involve management and oversight of short- and long-term planning and acquisition of  
16 power resources.

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

18 A. My testimony provides an overview of Avista's resource planning and power  
19 supply operations. This includes summaries of the Company's generation resources, the  
20 current and future load and resource position, and future resource plans. As part of an  
21 overview of the Company's risk management policy, I will provide an update on the  
22 Company's hedging practices. I will address hydroelectric and thermal project upgrades,  
23 followed by an update on recent developments regarding hydro licensing. The information

1 included within my testimony, related to increased costs associated with hydroelectric and  
2 thermal project upgrades, is provided for informational purposes only. As explained by  
3 Company witness Ms. Andrews, the Company is basing its electric revenue increase  
4 requested in this case based on its electric Attrition Studies. However, as a “cross check” to  
5 the Company’s request based on the electric Attrition Study, Ms. Andrews has also prepared  
6 an electric Pro Forma Cross Check Study, which incorporate Washington’s share of the  
7 capital additions described further in my testimony.<sup>1</sup>

8 A table of contents for my testimony is as follows:

| 9  | <u>Description</u>                         | <u>Page</u> |
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| 10 | I. Introduction                            | 1           |
| 11 | II. Resource Planning and Power Operations | 3           |
| 12 | III. Generation Capital Projects           | 11          |
| 13 | IV. Hydro Relicensing                      | 18          |

14  
15 **Q. Are you sponsoring any exhibits?**

16 A. Yes. Exhibit No. \_\_\_\_ (SJK-2) includes Avista’s 2013 Electric Integrated  
17 Resource Plan and Appendices, Exhibit No. \_\_\_\_ (SJK-3) provides a forecast of the  
18 Company’s load and resource positions from 2014 through 2033. Confidential Exhibit  
19 No. \_\_\_\_ (SJK-4C) includes Avista’s Energy Resources Risk Policy.

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<sup>1</sup> However, as noted later in my testimony at Section IV. Hydro Relicensing, the Company is seeking a prudence finding of the costs related to the improvement of dissolved oxygen levels in Lake Spokane, and amortization of these costs over a three-year period beginning in 2015. As discussed by Company witness Ms. Andrews, since the amortization of these costs start in 2015, they represent activity which was not included in the June 2013 normalized commission basis results used as the starting point of the Company’s Attrition Study analysis. Ms. Andrews, therefore, includes the Lake Spokane three-year amortization as an “After Attrition Adjustment” in both her Attrition and Pro Forma Cross Check Studies in determination of the Company’s final revenue requirement requested in this case.

1 **II. RESOURCE PLANNING AND POWER OPERATIONS**

2 **Q. Would you please provide a brief overview of Avista's owned-generating**  
3 **resources?**

4 A. Yes. Avista's owned generating resource portfolio includes hydroelectric  
5 generation projects, base-load coal and natural gas-fired thermal generation facilities, waste  
6 wood-fired generation, and natural gas-fired peaking generation. Avista-owned generation  
7 facilities have a total capability of 1,851 MW, which includes 58% hydroelectric and 42%  
8 thermal resources.

9 Illustration Nos. 1 and 2 summarize present net capability of Avista's hydroelectric  
10 and thermal owned-generation resources:

11 **Illustration No. 1: Avista-Owned Hydroelectric Generation**

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| Project Name               | River System | Nameplate Capacity (MW) | Maximum Capability (MW) | Expected Energy (aMW) |
|----------------------------|--------------|-------------------------|-------------------------|-----------------------|
| Monroe Street              | Spokane      | 14.8                    | 15.0                    | 11.6                  |
| Post Falls                 | Spokane      | 14.8                    | 18.0                    | 10.0                  |
| Nine Mile                  | Spokane      | 26.0                    | 17.5                    | 12.5                  |
| Little Falls               | Spokane      | 32.0                    | 35.2                    | 22.1                  |
| Long Lake                  | Spokane      | 81.6                    | 89.0                    | 53.4                  |
| Upper Falls                | Spokane      | 10.0                    | 10.2                    | 7.5                   |
| Cabinet Gorge              | Clark Fork   | 265.2                   | 270.5                   | 124.8                 |
| Noxon Rapids               | Clark Fork   | 518.0                   | 610.0                   | 198.3                 |
| <b>Total Hydroelectric</b> |              | <b>962.4</b>            | <b>1,065.4</b>          | <b>440.2</b>          |

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**Illustration No. 2: Avista-Owned Thermal Generation**

| Project Name     | Fuel Type | Start Date | Winter Maximum Capacity (MW) | Summer Maximum Capacity (MW) | Nameplate Capacity (MW) |
|------------------|-----------|------------|------------------------------|------------------------------|-------------------------|
| Colstrip 3 (15%) | Coal      | 1984       | 111.0                        | 111.0                        | 123.5                   |
| Colstrip 4 (15%) | Coal      | 1986       | 111.0                        | 111.0                        | 123.5                   |
| Rathdrum         | Gas       | 1995       | 178.0                        | 126.0                        | 166.5                   |
| Northeast        | Gas       | 1978       | 68.0                         | 42.0                         | 61.2                    |
| Boulder Park     | Gas       | 2002       | 24.6                         | 24.6                         | 24.6                    |
| Coyote Springs 2 | Gas       | 2003       | 312.0                        | 251.0                        | 290.0                   |
| Kettle Falls     | Wood      | 1983       | 47.0                         | 47.0                         | 50.7                    |
| Kettle Falls CT  | Gas       | 2002       | 11.0                         | 8.0                          | 7.5                     |
| <b>Total</b>     |           |            | <b>862.6</b>                 | <b>720.6</b>                 | <b>847.5</b>            |

**Q. Would you please provide a brief overview of Avista's major generation contracts?**

**A. Yes.** Avista's contracted-for generation resource portfolio consists of Mid-Columbia hydroelectric, PURPA, a tolling agreement for a natural gas-fired generator, and contracts with wind generation facilities.

The Company currently has long-term contractual rights for resources owned and operated by the Public Utility Districts of Chelan, Douglas and Grant counties. Illustration No. 3 provides details about the Mid-Columbia hydroelectric contracts. The current Rocky Reach and Rock Island contracts with Chelan PUD end in December 2014, but the Company will pursue new contracts with these plants through the auction process described in witness Mr. Johnson's testimony. Illustration No. 4 provides details about other contracts. Avista also has a long-term power purchase agreement (PPA) in place through 2026 entitling the Company to dispatch, purchase fuel for and receive the power output from the 275 MW Lancaster combined-cycle combustion turbine project located in Rathdrum, Idaho. In 2011,

1 the Company executed a 20-year power purchase agreement to purchase the output (105  
2 MW peak) and all environmental attributes from the Palouse Wind, LLC wind generation  
3 project that began commercial operation in December 2012.

4 **Illustration No. 3: Mid-Columbia Hydroelectric Capacity and Energy Contracts**

| Counter Party – Hydroelectric Project                | Share (%) | Start Date | End Date | Estimated On-Peak Capability (MW) | Annual Energy (aMW) |
|--|-----------|------------|----------|-----------------------------------|---------------------|
| Grant PUD – Priest Rapids                            | 3.7       | 12/2001    | 12/2052  | 28.2                              | 16.7                |
| Grant PUD – Wanapum                                  | 3.7       | 12/2001    | 12/2052  | 31.0                              | 17.9                |
| Chelan PUD – Rocky Reach                             | 3.0       | 7/2011     | 12/2014  | 34.5                              | 21.0                |
| Chelan PUD – Rock Island                             | 3.0       | 7/2011     | 12/2014  | 13.9                              | 10.7                |
| Douglas PUD - Wells                                  | 3.3       | 2/1965     | 8/2018   | 27.9                              | 14.7                |
| <b>Canadian Entitlement</b>                          |           |            |          | <b>-8.1</b>                       | <b>-4.6</b>         |
| <b>2014 Total Net Contracted Capacity and Energy</b> |           |            |          | <b>127.4</b>                      | <b>76.4</b>         |
| <b>2015 Total Net Contracted Capacity and Energy</b> |           |            |          | <b>81.9</b>                       | <b>46.3</b>         |

14 **Illustration No. 4: Other Contractual Rights and Obligations**

| Contract                              | Type     | Fuel Source | End Date | Winter Capacity (MW) | Summer Capacity (MW) | Annual Energy (aMW) |
|---------------------------------------|----------|-------------|----------|----------------------|----------------------|---------------------|
| Stateline                             | Purchase | Wind        | 3/2014   | 0                    | 0                    | 9                   |
| Sacramento Municipal Utility District | Sale     | System      | 12/2014  | -50                  | -50                  | -50                 |
| PGE Capacity Exchange                 | Exchange | System      | 12/2016  | -150                 | -150                 | 0                   |
| Douglas Settlement                    | Purchase | Hydro       | 9/2018   | 2                    | 2                    | 3                   |
| WNP-3                                 | Purchase | System      | 6/2019   | 82                   | 0                    | 42                  |
| Lancaster                             | Purchase | Gas         | 10/2026  | 290                  | 249                  | 222                 |
| Palouse Wind                          | Purchase | Wind        | 12/2042  | 0                    | 0                    | 40                  |
| Nichols Pumping                       | Sale     | System      | 10/2018  | -6.8                 | -6.8                 | -6.8                |
| PURPA Contracts                       | Purchase | Varies      | Varies   | 50.5                 | 50.5                 | 30.5                |
| <b>Total</b>                          |          |             |          | <b>217.7</b>         | <b>94.7</b>          | <b>289.7</b>        |

1           **Q.    Has the interconnection with the Lancaster Substation been completed?**

2           A.    Yes. Avista entered into a process with the Bonneville Power Administration  
3 (BPA) through a Line and Load Interconnection request on September 2, 2009, to perform a  
4 joint study concerning the interconnection of Avista's 230 kV transmission lines to the BPA  
5 Lancaster Substation. The BPA completed its Line and Load Interconnection System  
6 Impact Study on August 20, 2010 and completed its Line and Load Interconnection  
7 Facilities Study on November 8, 2011. An environmental impact study was performed and  
8 a construction agreement was entered into with the BPA. The interconnection between  
9 Avista's 230 kV line and the Lancaster Substation was completed on December 13, 2013.  
10 Avista gave the required two-year notice to the BPA to terminate 150 MW of transmission  
11 service on August 31, 2012. The BPA accepted the request to terminate the 150 MW of  
12 transmission service effective August 31, 2014. Please refer to witness Ms. Rosentrater for  
13 additional details about this interconnection.

14           **Q.    Would you please provide a summary of Avista's power supply**  
15 **operations and acquisition of new resources?**

16           A.    Yes. Avista uses a combination of owned and contracted-for resources to  
17 serve its load requirements. The Power Supply Department is responsible for dispatch  
18 decisions related to those resources for which the Company has dispatch rights. The  
19 Department monitors and routinely studies capacity and energy resource needs. Short- and  
20 medium-term wholesale transactions are used to economically balance resources with load  
21 requirements. The Integrated Resource Plan (IRP) generally guides longer-term resource  
22 decisions such as the acquisition of new generation resources, upgrades to existing  
23 resources, demand-side management (DSM), and long-term contract purchases. Resource

1 acquisitions typically include a Request for Proposals (RFP) and/or other market due  
2 diligence processes.

3 **Q. Please summarize Avista's current load and resource position.**

4 A. Avista's 2013 IRP shows forecasted annual energy deficits beginning in  
5 2026, and sustained annual capacity deficits beginning in 2020.<sup>2</sup> These capacity and energy  
6 load/resource positions are shown on pages 2-39 through 2-41 of Exhibit No. \_\_\_\_ (SJK-2).  
7 Exhibit No. \_\_\_\_ (SJK-3) shows our most recent load and resource projection. Avista's IRP  
8 projection shows an annual energy deficit beginning in 2026 of about 19 aMW, and  
9 increasing to a 284 aMW deficit in 2033. The Company's January capacity resource  
10 position, based on an 18-hour peak event (6 hours per day and over 3 days), is projected to  
11 be surplus through 2019. Sustained annual capacity deficiencies, based on a January peak,  
12 begin at 42 MW in 2020 and increase to a 551 MW deficit in 2033. The Company's August  
13 capacity resource position, based on an 18-hour peak event, is projected to be surplus  
14 through 2023. Sustained annual capacity deficiencies, based on an August peak, begin at 2  
15 MW in 2024 and increase to a 361 MW deficit in 2033.

16 **Q. How does Avista plan to meet future energy and capacity needs?**

17 A. The Company will be guided by the 2013 Preferred Resource Strategy (PRS).  
18 The current PRS is described in the 2013 Electric IRP, which is attached as Exhibit  
19 No. \_\_\_\_ (SJK-2). The IRP provides details about future resource needs, specific resource  
20 costs, resource-operating characteristics, and the scenarios used for evaluating the mix of  
21 resources for the PRS. The Company's 2013 Electric IRP was submitted to the Commission

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<sup>2</sup> The Company has a 150 MW capacity exchange agreement with Portland General Electric that ends in December 2016 and Avista has short-term annual capacity deficits in 2015 and 2016. Sustained annual capacity deficits begin in 2020.

1 on August 30, 2013, following the completion of a public process involving six Technical  
2 Advisory Committee meetings from May 23, 2012 through June 19, 2013. The Commission  
3 is reviewing the 2013 Electric IRP in Docket No. UE-121421. The IRP represents the  
4 preferred plan at a point in time; however, Avista continues evaluating different resource  
5 options to meet future load requirements and will file its next IRP in August 2015.

6 Avista's 2013 PRS includes less than one MW of distribution efficiencies, 221 MWs  
7 of cumulative energy efficiency, 19 MWs of demand response, 6 MWs of upgrades to  
8 existing thermal plants, and 569 MWs of natural gas-fired plants (299 MWs of simple cycle  
9 combustion turbines (SCCT) and 270 MWs of combined-cycle combustion turbine  
10 (CCCT)). The timing and type of these resources as published in the 2013 IRP is provided  
11 in Illustration No. 5.

12 **Illustration No. 5: 2013 Electric IRP Preferred Resource Strategy**

| Resource Type                    | By the End of Year        | Nameplate (MW)             | Energy (aMW)        |
|----------------------------------|---------------------------|----------------------------|---------------------|
| SCCT                             | 2019                      | 83                         | 76                  |
| SCCT                             | 2023                      | 83                         | 76                  |
| CCCT                             | 2026                      | 270                        | 248                 |
| SCCT                             | 2027                      | 83                         | 76                  |
| Rathdrum CT Upgrade              | 2028                      | 6                          | 5                   |
| SCCT                             | 2032                      | 50                         | 46                  |
| <b>Total</b>                     |                           | <b>575</b>                 | <b>529</b>          |
| <b>Efficiency Improvements</b>   |                           |                            |                     |
|                                  | <b>By the End of Year</b> | <b>Peak Reduction (MW)</b> | <b>Energy (aMW)</b> |
| <b>Energy Efficiency</b>         | 2014-2033                 | 221                        | 164                 |
| <b>Demand Response</b>           | 2022-2027                 | 19                         | 0                   |
| <b>Distribution Efficiencies</b> | 2014-2017                 | <1                         | <1                  |
| <b>Total Efficiency</b>          |                           | <b>240</b>                 | <b>164</b>          |

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22 **Q. Would you please provide a high-level summary of Avista's risk**  
23 **management program for energy resources?**

1           A.     Yes. Avista Utilities uses several techniques to manage the risks associated  
2 with serving load and managing Company-owned and controlled resources. The Energy  
3 Resources Risk Policy, which is attached as Confidential Exhibit No. \_\_\_\_ (SJK-4C), provides  
4 general guidance to manage the Company's energy risk exposure relating to electric power  
5 and natural gas resources over the long-term (more than 41 months), the short-term  
6 (monthly and quarterly periods up to approximately 41 months), and the immediate term  
7 (present month).

8           The Energy Resources Risk Policy is not a specific procurement plan for buying or  
9 selling power or natural gas at any particular time, but is a guideline used by management  
10 when making procurement decisions for electric power and natural gas fuel for generation.  
11 The policy considers several factors, including the variability associated with loads,  
12 hydroelectric generation, and electric power and natural gas prices in the decision-making  
13 process regarding procurement of electric power and natural gas for generation.

14          Avista aims to develop or acquire long-term energy resources based on the  
15 Integrated Resource Plan's Preferred Resource Strategy, while taking advantage of  
16 competitive opportunities to satisfy electric resource supply needs in the long-term period.  
17 Electric power and natural gas fuel transactions in the immediate term are driven by a  
18 combination of factors that incorporate both economics and operations, including near-term  
19 market conditions (price and liquidity), generation economics, project license requirements,  
20 load and generation variability, reliability considerations, and other near-term operational  
21 factors.

22          For the short-term timeframe, which falls between the long-term and immediate term  
23 periods, the Company's Energy Resources Risk Policy guides its approach to hedging

1 financially open forward positions. A financially open forward period position may be the  
2 result of either a short position situation, for which the Company has not yet purchased the  
3 fixed-price fuel to generate, or alternatively purchased fixed-price electric power from the  
4 market, to meet projected average load for the forward period. Or it may be a long position,  
5 for which the Company has generation above its expected average load needs, and has not  
6 yet made a fixed-price sale of that surplus to the market in order to balance resources and  
7 loads.

8 The Company employs an Electric Hedging Plan to guide power supply position  
9 management in the short-term period. The Risk Policy Electric Hedging Plan is essentially a  
10 price diversification approach employing a layering strategy for forward purchases and sales  
11 of either natural gas fuel for generation or electric power in order to approach a generally  
12 balanced position against expected load as forward periods draw nearer.

13 **Q. What is the status of Avista's plans to meet the renewable portfolio**  
14 **standard (RPS) in Washington beginning in 2012?**

15 A. The Energy Independence Act, RCW Chapter 19.285, resulting from  
16 Initiative 937, requires utilities with more than 25,000 customers to comply with a  
17 renewable portfolio standard by meeting 3% of their load by 2012, 9% by 2016, and 15% by  
18 2020 with qualified renewable energy generation or renewable energy credits (RECs).

19 Avista plans to meet its RPS obligations with qualified hydroelectric upgrades,  
20 purchased RECs, wind generation, and qualifying biomass generation starting in 2016.  
21 Illustration No. 6 shows Avista's projected net REC position from 2014 through 2020 before  
22 applying the rollover provision. RECs associated with the Palouse Wind project include the  
23 apprenticeship credit. The Washington State Apprenticeship and Training Council approved

1 the apprenticeship credit certification on October 23, 2013. The sale of excess REC's is  
2 addressed in witness Mr. Johnson's testimony.

3 **Illustration No. 6: Washington Renewable Portfolio Standard Requirements (aMW)**

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| Year | Percentage of Washington Load | Total Projected Need | REC Position in Excess of Need |
|------|-------------------------------|----------------------|--------------------------------|
| 2014 | 3%                            | 18.9                 | 47.9                           |
| 2015 | 3%                            | 19.1                 | 53.6                           |
| 2016 | 9%                            | 57.9                 | 45.3                           |
| 2017 | 9%                            | 58.3                 | 44.4                           |
| 2018 | 9%                            | 58.9                 | 43.7                           |
| 2019 | 9%                            | 59.5                 | 43.7                           |
| 2020 | 15%                           | 100.0                | 3.1                            |

12

13 **III. GENERATION CAPITAL PROJECTS**

14 **Q. Would you please provide a brief description of the generation-related**  
15 **capital projects that occurred in the last half of 2013 and are planned for in 2014 and**  
16 **2015?**

17 **A. Yes.** As shown in Illustration No. 7, the total 2013, 2014 and 2015  
18 generation capital projects to be completed, as discussed by Mr. DeFelice, total \$15.216  
19 million, \$52.641 million and \$98.677 million, respectively on a system basis. Details about  
20 the 26 generation capital projects totaling \$167 million are discussed below.

1 **Illustration No. 7: 2013 – 2015 Generation Capital Projects Summary**

2

3 **\$ (000's)**

| 4  | <b>Generation / Production (System):</b>     | <b>Jul-Dec 2013</b> | <b>2014</b>      | <b>2015</b>      |
|----|--|---------------------|------------------|------------------|
| 4  | Hydro - Base Load Hydro                      | \$ 903              | \$ 1,000         | \$ 1,000         |
|    | Hydro - Clark Fork Settlement Agreement      | 1,719               | 10,830           | 7,081            |
| 5  | Hydro - Generation Battery Replacement       | 112                 | 100              | 183              |
|    | Hydro - Hydro Safety Minor Blanket           | 50                  | 65               | 70               |
| 6  | Hydro - Little Falls Plant Upgrade           | 27                  | 9,000            | 6,500            |
|    | Hydro - Nine Mile Rehab                      | 990                 | 9,208            | 47,044           |
| 7  | Hydro - Regulating Hydro                     | 3,292               | 2,500            | 3,000            |
|    | Hydro - Spokane River License Implementation | 1,860               | 4,815            | 462              |
| 8  | Thermal - Base Load Thermal Plant            | 4,135               | 2,200            | 2,200            |
|    | Thermal - Peaking Generation                 | 1,000               | 500              | 500              |
| 9  | Hydro - Post Falls Intake Gate               | 1                   | -                | -                |
|    | Other - Coyote Springs LTSA                  | 179                 | -                | -                |
| 10 | Other - Rathdrum CT Upgrade Unit             | 45                  | -                | -                |
|    | Hydro - Long Lake Replace Field Windings     | -                   | 800              | 2,430            |
|    | Hydro - Noxon Spare Coils                    | -                   | 1,350            | -                |
| 11 | Other - CS2 Inlet Air Sys                    | -                   | 500              | -                |
|    | Thermal - Colstrip Thermal Capital           | -                   | 8,004            | 3,177            |
| 12 | Thermal - Kettle Falls Water Supply          | -                   | 1,615            | -                |
|    | Hydro - Post Falls South Channel Replacement | -                   | -                | 11,008           |
| 13 | Hydro - Cabinet Gorge Unit 1 Refurbishment   | -                   | -                | 11,400           |
|    | Thermal - KFGS Ash Collector                 | -                   | -                | 1,907            |
| 14 |  | <b>\$ 14,312</b>    | <b>\$ 52,488</b> | <b>\$ 97,962</b> |

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17

1 **Base Load Hydro: \$2,903,000 (\$903,000 in 2013, \$1,000,000 in 2014 and \$1,000,000 in**  
2 **2015)**

3 This program covers the capital maintenance expenditures required to keep Avista's Upper  
4 Spokane River hydroelectric plants operating within 90% of their current performance,  
5 assuming some degradation of performance over time. The plants covered in this program  
6 include Post Falls, Upper Falls, Monroe Street, and Nine Mile. The program focuses on  
7 ways to maintain compliance and reduce overall operations and maintenance expenses while  
8 maintaining a reasonable unit availability through a programmatic approach, rather than  
9 reacting to problems as they develop. The historical availability for the base load hydro  
10 plants has been declining over the past decade due to deteriorating equipment and a need to  
11 replace some equipment and systems that are about 100 years old. There is also \$1,075,000  
12 in projected capital costs for 2016.

13  
14 **Base Load Thermal Plant: \$8,535,000 (\$4,135,000 in 2013, \$2,200,000 in 2014 and**  
15 **\$2,200,000 in 2015)**

16 This program is necessary to sustain or improve the existing operating costs of base load  
17 thermal generating stations, including Coyote Springs 2, Colstrip, and Kettle Falls. Capital  
18 projects include replacement of items identified through asset management decisions and  
19 programs necessary to maintain reliable and low operating costs of these plants. As this  
20 program proceeds, it is expected that forced outage rates and forced derates of these  
21 facilities will decrease to a level one standard deviation less than the current average  
22 resulting in more economic benefits of the project. There is also \$2,205,000 in projected  
23 capital costs in 2016.

24  
25 **Cabinet Gorge HED Unit #1 Refurbishment: \$11,400,000 (All in 2015)**

26 This is the capital portion of a major overhaul project planned for Cabinet Gorge Unit #1.  
27 The runner hub has significant mechanical issues and needs to be replaced to allow for  
28 frequent cycling associated with the integration of intermittent renewable resources. The  
29 present automatic voltage regulator provides a relatively slow response due to its hybrid  
30 design and has no limiters for generator protection. A new system will provide faster  
31 response and add limiters. The machine monitoring is to allow for better analysis of  
32 machine condition for this critical unit. New protective relays will be installed and new  
33 controls will be integrated with the project to replace the failing Bailey NET90 system.  
34 Rehabilitation of this unit will also allow flexibility around minimum flow for fish habitat.

35  
36 **Colstrip Capital Additions: \$11,595,168 (\$0 in 2013, \$8,004,285 in 2014 and \$3,176,850**  
37 **in 2015)**

38 This program includes ongoing capital expenditures associated with normal outage activities  
39 on Units 3 & 4 at Colstrip. Every 2 out of 3 years, there are planned outages at Colstrip with  
40 higher capital program activities. For non-outage years, the program activities are reduced.  
41 Avista votes its 15% share of Unit's 3 & 4 and its approximate 10% share of common  
42 facilities to approve or disapprove of the budget proposed by PPLM on behalf of all the  
43 owners. Individual projects are reviewed for appropriate rates of return and necessity.  
44 There is also \$5,836,350 in projected capital costs in 2016.

1 **Coyote Springs 2 LTSA Cash Accrual: \$179,000 (All in 2013)**

2 This program covers the capital accruals required to execute our Long Term Service  
3 Agreement (LTSA) with General Electric for Coyote Springs Unit 2. This program will  
4 have fluctuations to account for the variable operating hours and operating conditions that  
5 feed into the LTSA formula.

6  
7 **Coyote Springs 2 Inlet Air System \$500,000 (All in 2014)**

8 This project replaces the present air filters with a new system that is more effective at  
9 particulate removal than the current system. cursory studies indicate that these new filters  
10 would reduce the number of water washes required to maintain unrestricted airflow, and  
11 reduce the particles going through the turbine, which in turn reduces erosion on the blades  
12 and buckets. O&M savings of \$20,587 are estimated for 2014 due to avoiding performance  
13 level decreases experienced over time if the system is not replaced.

14  
15 **Rathdrum CT Upgrade Unit 1 to Mark VI Control: \$45,000 (All in 2013)**

16 In 2007, the Mark V controller on Rathdrum Unit 2 failed, taking the unit out of service for  
17 several months. A new Mark VI controller was installed in its place. This project replaces  
18 the old Mark V controller in Unit 1 with a Mark VI controller to match Unit 2. The Mark V  
19 technology is at the end of its life and is minimally supported by the manufacturer.

20  
21 **Generation Battery Replacement: \$395,000 (\$112,000 in 2013, \$100,000 in 2014, and  
22 \$183,000 in 2015)**

23 This program is based on an asset management plan for the station batteries in all generating  
24 stations. This item will also have some minor fluctuations as the number and size of  
25 batteries in any particular year can change. There is also \$115,000 in projected capital costs  
26 in 2016.

27  
28 **Kettle Falls Develop New River Wells: \$1,615,000 (All in 2014)**

29 The Kettle Falls Generating Station receives its water from the City of Kettle Falls through  
30 an agreement that dates to the construction of the plant in the early 1980's. That agreement  
31 expires next year and future water rates with the City of Kettle Falls will be higher, directly  
32 impacting the operating costs of the plant. The necessary new water rights have been  
33 procured and this project includes the construction of the water supply system to the plant  
34 that will be controlled and operated by the Company. O&M savings of \$18,750 are expected  
35 in 2015 related to the reduction in the amount paid for water expense.

36  
37 **Kettle Falls Generation Station Ash Collector: \$1,907,000 (All in 2015)**

38 This project is to replace the mechanical ash collector at the Kettle Falls Generating Station.  
39 The current unit is the original plant equipment and requires frequent repair of metal  
40 surfaces due to ash abrasion, requiring plant outages. O&M savings are estimated to be  
41 \$75,000 in 2015 due to the reduction of maintenance costs associated with ash abrasion.

42  
43 **Little Falls Powerhouse Redevelopment: \$15,527,000 (\$27,000 in 2013, \$9,000,000 in  
44 2014, and \$6,500,000 in 2015)**

1 The existing Little Falls equipment ranges in age from 60 to more than 100 years old.  
2 Forced outages at Little Falls because of equipment failures have significantly increased  
3 over the past six years, from about 20 hours in 2004 to several hundred hours in the past  
4 three to four years. This project will replace nearly all of the older, unreliable equipment  
5 with new equipment. This project includes replacing two of the turbines, all four generators,  
6 all generator breakers, three of the four governors, all of the automatic voltage regulators,  
7 removing all four generator exciters, replacing the unit controls, changing the switchyard  
8 configuration, replacing the unit protection system, and replacing and modernizing the  
9 station service. There is also \$9,000,000 in capital costs projected in 2016. An O&M Offset  
10 was included in the O&M Offset Adjustment in the amount of \$5,000 (\$3,250 WA). After  
11 revenue requirement was finalized, it was determined that no offsets exist for this business  
12 case as the associated savings are due to employee labor that will be redistributed to other  
13 projects.  
14

15 **Long Lake HED Replace Field Windings: \$3,230,000 (\$800,000 in 2014 and \$2,430,000**  
16 **in 2015)**

17 Over the past 10 years, there has been a continuing decline in the insulation level on the  
18 generators at Long Lake. This decline is measured using Megger test instruments. Long  
19 Lake has experienced an increasing amount of forced outages and down time due to the  
20 condition of these units. There is also \$170,000 in capital costs projected in 2016.  
21

22 **Nine Mile Redevelopment: \$57,241,997 (\$990,000 in 2013, \$9,208,122 in 2014, and**  
23 **\$47,043,875 in 2015)**

24 This capital program is to rehabilitate and modernize the four unit Nine Mile HED. The  
25 program includes projects to replace the existing 3 MW Units 1 and 2, which are more than  
26 100 years old and worn out, with two new 8 MW generators/turbines. Once operational in  
27 2016, the new units will add 1.4 aMW of energy beyond the original configuration and 6.4  
28 MW of capacity above current generation levels. In addition to these capacity upgrades, the  
29 Nine Mile facility will receive upgrades to the following:

- 30 • hydraulic governors;
- 31 • static excitation system;
- 32 • switchgear;
- 33 • station service;
- 34 • control and protection packages;
- 35 • ventilation upgrades;
- 36 • rehabilitation of intake gates and sediment bypass system;
- 37 • a new warehouse will be constructed;
- 38 • new tail race gate system will be added;
- 39 • new grounding and communications will be added;
- 40 • a barge landing will be added;
- 41 • a cottage will be removed and another remodeled;
- 42 • a new panel room will be added;

- 1 • Units 3 and 4 will be overhauled and modernized;
- 2 • the powerhouse will be restored;
- 3 • new access gates and controls will be added; and
- 4 • other improvements will be made.

5  
6 The fall 2013 Unit 4 overhaul includes new turbine runners, thrust bearings, and operating system.  
7 There is \$13,800,983 in capital costs expected in 2016.

8  
9 **Peaking Generation: \$2,000,000 (\$1,000,000 in 2013, \$500,000 in 2014, and \$500,000 in**  
10 **2015)**

11 This program covers the capital maintenance expenditures required to keep the natural gas-  
12 fired peaking units (Boulder Park, Rathdrum CT, and Northeast CT) operating at or above  
13 their current performance levels. The program focuses on maximizing the ability of these  
14 units to start and run when demanded (starting reliability). There is also \$500,000 in capital  
15 costs expected in 2016.

16  
17 **Post Falls Intake Gate Replacement: \$1,000 (All in 2013)**

18 This project is essentially complete and involved replacing the wooden timbered head gates  
19 at Post Falls with new steel gates and modifying the structure to include a hoist system.  
20 Provisions for the gates were made to pull the gates out for easy maintenance purposes.  
21 This work also included installation of new controls and appropriate emergency power  
22 systems.

23  
24 **Post Falls South Channel Gate Replacement: \$11,008,000 (All in 2015)**

25 Avista has planned to maintain the south channel gates to comply with FERC Dam Safety  
26 directives. A pre-construction underwater investigation revealed that the condition of the  
27 concrete structure was very poor and would not handle the planned work. This resulted in  
28 an effort to evaluate options. This capital item includes preliminary engineering of different  
29 replacement options and project estimates. The project entails removing most of the  
30 existing concrete structure and replacing it with a new concrete structure, new spillway  
31 gates, and new hoist systems to automate gate operation. An O&M Offset was included in  
32 the O&M Offset Adjustment in the amount of \$5,000 (\$3,250 WA). After the revenue  
33 requirement was finalized, it was determined that no offsets exist for this business case as  
34 the associated savings are due to employee labor that will be redistributed to other projects.

35  
36 **Regulating Hydro: \$8,792,000 (\$ 3,292,000 in 2013, \$2,500,000 in 2014, and \$3,000,000**  
37 **in 2015)**

38 This program covers the capital maintenance expenditures required to keep the Long Lake,  
39 Little Falls, Noxon Rapids and Cabinet Gorge plants operating at their current performance

1 levels. The program will work to improve the reliability of these plants so that their value  
2 can be maximized in both the energy and ancillary markets. There is also \$3,000,000 in  
3 capital costs expected in 2016.

4  
5 **Clark Fork Settlement Agreement: \$19,630,000 (\$1,719,000 in 2013, \$10,830,000 in**  
6 **2014, and \$7,081,000 in 2015)**

7 These capital costs are required for the facilitation of the Clark Fork Protection, Mitigation  
8 and Enhancement (PM&E) measures. The Implementation of programs is done through the  
9 License issued to Avista Corporation for a period of 45 years, effective March 1, 2001, to  
10 operate and maintain the Clark Fork Project No. 2058. The License includes hundreds of  
11 specific legal requirements, many of which are reflected in License Articles 404-430. These  
12 Articles derived from a comprehensive settlement agreement between Avista and 27 other  
13 parties, including the States of Idaho and Montana, various federal agencies, five Native  
14 American tribes, and numerous Non Governmental Organizations. Avista is required to  
15 develop, in consultation with the Management Committee, a yearly work plan and report,  
16 addressing all PM&E measures of the License. In addition, implementation of these  
17 measures is intended to address ongoing compliance with Montana and Idaho Clean Water  
18 Act requirements, the Endangered Species Act (fish passage), and state, federal and tribal  
19 water quality standards as applicable. License articles also describe our operational  
20 requirements for items such as minimum flows, ramping rates and reservoir levels, as well  
21 as dam safety and public safety requirements. There is also \$21,846,280 in capital costs  
22 expected in 2016.

23 **Spokane River Implementation PM&E: \$7,137,000 (\$1,860,000 in 2013, \$4,815,000 in**  
24 **2014, and \$462,000 in 2015)**

25 Implementation of Protection, Mitigation and Enhancement (PM&E) programs related to the  
26 FERC License for the Spokane River. This includes items enforceable by FERC, mandatory  
27 conditioning agencies, and through settlement agreements. Additional details concerning  
28 the PM&E measures for the Spokane River license are included in the hydro relicensing  
29 section that follows. There is also \$16,222,000 in capital costs expected in 2016.

30  
31 **Hydro Safety Minor Blanket: \$185,000 (\$50,000 in 2013, \$65,000 in 2014, and \$70,000**  
32 **in 2015)**

33 This item funds periodic capital purchases and projects to ensure public safety at hydro  
34 facilities, on and off water, in the context of FERC regulatory and license requirements.  
35 There is also \$75,000 in capital costs expected in 2016.

1           **Q.     Would you please provide an update on the Colstrip Unit #4 outage?**

2           A.     Yes. Colstrip Unit #4 experienced an unplanned outage on July 1, 2013  
3 resulting from damage caused by a ground fault on the “B” phase stator of the main  
4 generator. This damage required a rebuild of the Unit #4 generator. The unit was started  
5 under test conditions on January 23, 2014 and released for full operation on January 25,  
6 2014.

7

8

**IV. HYDRO RELICENSING**

9           **Q.     Would you please provide an update on work being done under the**  
10 **existing FERC operating license for the Company’s Clark Fork River generation**  
11 **projects?**

12          A.     Yes. Avista received a new 45-year FERC operating license for its Cabinet  
13 Gorge and Noxon Rapids hydroelectric generating facilities on the Clark Fork River on  
14 March 1, 2001. The Company has continued to work with the 27 Clark Fork Settlement  
15 Agreement signatories to meet the goals, terms, and conditions of the Protection, Mitigation  
16 and Enhancement (PM&E) measures under the license. The implementation program, in  
17 coordination with the Management Committee which oversees the collaborative effort, has  
18 resulted in the protection of approximately 3000 acres of bull trout, wetlands, uplands, and  
19 riparian habitat. More than 37 individual stream habitat restoration projects have occurred  
20 on 23 different tributaries within our project area. Avista has collected data on over 17,000  
21 individual bull trout within the project area. The upstream fish passage program, using  
22 electrofishing, trapping and hook-and-line capture efforts, has reestablished bull trout  
23 connectivity between Lake Pend Oreille and the Clark Fork River tributaries above Cabinet

1 Gorge and Noxon Rapids Dams through the upstream transport of 438 adult bull trout, with  
2 over 160 of these radio tagged and their movements studied. Avista has worked with the  
3 U.S. Fish and Wildlife Service to develop and test two experimental fish passage facilities.  
4 Avista, in consultation with key state and federal agencies, is currently developing designs  
5 for a permanent upstream adult fishway for Cabinet Gorge and Noxon Rapids. In 2013,  
6 designs for the Cabinet Gorge Fishway Fish Handling and Holding Facility were completed  
7 and construction was initiated. A permanent tributary trap on Graves Creek (an important  
8 bull trout spawning tributary) was constructed in 2012 and testing began 2013. A three year  
9 evaluation process is ongoing to determine if future permanent tributary traps are warranted

10 Recreation facility improvements have been made to over 24 sites along the  
11 reservoirs. Avista also owns and manages over 100 miles of shoreline that includes 3,500  
12 acres of property to meet FERC required natural resource goals while allowing for public  
13 use of these lands where appropriate.

14 Finally, tribal members continue to monitor known cultural and historic resources  
15 located within the project boundary to ensure that these sites are appropriately protected.

16 **Q. Would you please provide an update on the current status of managing**  
17 **total dissolved gas issues at Cabinet Gorge dam?**

18 A. Yes. How best to deal with total dissolved gas (TDG) levels occurring  
19 during spill periods at Cabinet Gorge Dam was unresolved when the current Clark Fork  
20 license was received. The license provided time to study the actual biological impacts of  
21 dissolved gas and to subsequently develop a dissolved gas mitigation plan. Stakeholders,  
22 through the Management Committee, ultimately concluded that dissolved gas levels should  
23 be mitigated, in accordance with federal and state laws. A plan to reduce dissolved gas

1 levels was developed with all stakeholders, including the Idaho Department of  
2 Environmental Quality. The original plan called for the modification of two existing  
3 diversion tunnels, which could redirect stream flows exceeding turbine capacity away from  
4 the spillway.

5 The 2006 Preliminary Design Development Report for the Cabinet Gorge Bypass  
6 Tunnels Project indicated that the preferred tunnel configuration did not meet the  
7 performance, cost and schedule criteria established in the approved Gas Supersaturation  
8 Control Plan (GSCP). This led the Gas Supersaturation Subcommittee to determine that the  
9 Cabinet Gorge Bypass Tunnels Project was not a viable alternative to meet the GSCP. The  
10 subcommittee then developed an addendum to the original GSCP to evaluate alternative  
11 approaches to the Tunnel Project.

12 In September 2009, the Management Committee agreed with the proposed  
13 addendum, which replaces the Tunnel Project with a series of smaller TDG reduction  
14 efforts, combined with mitigation efforts during the time design and construction of  
15 abatement solutions take place.

16 FERC approved the GSCP addendum in February 2010 and in April 2010 the Gas  
17 Supersaturation Subcommittee (a subcommittee of the MC) chose five TDG abatement  
18 alternatives for feasibility studies. Feasibility studies and design continue on two of the  
19 alternatives. Final design, construction, and testing of the spillway crest modification  
20 prototype was completed in 2013. Test results indicated over all TDG performance was  
21 positive, however, additional modifications are required to address cavitations issues.  
22 Modification of the spillway crest prototype and retesting is anticipated in 2014.

1           **Q.     Would you please give a brief update on the status of the work being**  
2 **done under the new Spokane River Hydroelectric Project's license?**

3           A.     Yes. The Company received a new 50-year license for the Spokane River  
4 Project on June 18, 2009. The License incorporated key agreements with the Department of  
5 Interior and other key parties in both Idaho and Washington. Implementation of the new  
6 license began immediately, with the development of over 40 work plans prepared, reviewed  
7 and approved, as required, by the Idaho Department of Environmental Quality, Washington  
8 Department of Ecology, the U.S. Department of Interior, and FERC. The work plans pertain  
9 not only to license requirements, but also to meeting requirements under Clean Water Act  
10 401 certifications by both Idaho and Washington and other mandatory conditions issued by  
11 the U.S. Department of Interior.

12           Since 2011, Avista has implemented water quality, fisheries, recreation, cultural,  
13 erosion, wetland, aquatic weed management, aesthetic, operational and related conditions  
14 (PM&E measures) across all five hydro developments. The majority of the PM&E  
15 measures are on-going in nature, however a number are one-time improvements, such as the  
16 Upper Falls aesthetic spill project located in downtown Spokane. Six hundred and fifty six  
17 acres of wetland mitigation properties were acquired in 2011 and 2012 on Upper Hangman  
18 Creek in Idaho for the Coeur d'Alene Tribe through the Coeur d'Alene Reservation Trust  
19 Resources Restoration Fund that Avista established in 2009. The Company developed  
20 wetland restoration plans for approximately 500 of the required 1,368 replacement acres of  
21 wetland and riparian habitat and are waiting for approval by the US Department of Interior,  
22 Bureau of Indian Affairs to continue implementing the plans. We completed a multi-year  
23 wetland mitigation project for 124 acres of property along the St. Joe River in 2013 and will

1 be responsible for maintaining approximately half of it, which lies on Avista's property, for  
2 the License term. We also completed over one mile of erosion control along the same  
3 stretch of river in 2013, with approximately half being on Avista property.

4 We continued work with the various local, state, and federal agencies to complete  
5 more of the required recreation projects in Idaho such as trail and interpretive sign  
6 improvements in Post Falls, and boat launch improvements along the Coeur d'Alene and St.  
7 Maries Rivers. In Washington we completed the designs for ten boat-in-only campsites on  
8 Lake Spokane that will be developed in 2014, and completed other improvements at our  
9 overlooks and interpretive areas on Lake Spokane and in Nine Mile Falls. We purchased  
10 109 acres of wetlands along the Little Spokane River and are currently developing a  
11 management plan for it, in order to fulfill required conditions.

12 In 2014, we will continue to develop and implement local, state, and federally  
13 required work plans to fulfill License conditions.

14 A number of the approved work plans require the Company to conduct extensive  
15 studies to determine appropriate measures to mitigate resource impacts. The more  
16 significant studies and mitigation measures include those for total dissolved gas (TDG)  
17 downstream of Long Lake Dam, which we began modeling in 2011. Avista is now in the  
18 process of having spillway modifications designed for construction to begin as early as  
19 2015. The Company completed the proposed dissolved oxygen (DO) measure in the tailrace  
20 below Long Lake Dam and is continuing to evaluate potential measures to improve DO in  
21 Lake Spokane, the reservoir created by the Long Lake Dam. Initial estimates for measures  
22 to address TDG range between \$7.0 and \$17.0 million, and between \$2.5 and \$8.0 million to

1 address DO in Lake Spokane. These estimates will be further refined as the relevant  
2 evaluations and studies are completed.

3 **Q. Please describe further the work completed by the Company to study the**  
4 **total dissolved gas downstream of Long Lake Dam.**

5 A. This was the subject of a deferred accounting order allowing the Company to  
6 seek recovery of costs in this rate case. The Long Lake development is one of five Avista  
7 hydroelectric developments that are a part of Avista's Spokane River Project. The Spokane  
8 River Project consists of five hydroelectric developments between Coeur d'Alene Lake in  
9 Idaho and Long Lake Dam in Washington (Post Falls, Upper Falls, Monroe Street, Nine  
10 Mile and Long Lake). The Spokane River Project is the subject of Federal Energy  
11 Regulatory Commission ("FERC") Project License 2545, a 50-year license issued by FERC  
12 on June 18, 2009.

13 Simultaneous to Avista's work on its Spokane River relicensing process (2002-  
14 2009), the Washington Department of Ecology ("Ecology") undertook a Dissolved Oxygen  
15 Total Maximum Daily Load ("TMDL") process to address impaired water quality in the  
16 Spokane River due to low dissolved oxygen levels. A TMDL is a requirement under the  
17 State of Washington's Clean Water Act obligations. One of the areas listed as "impaired"  
18 for low dissolved oxygen under the Clean Water Act includes Lake Spokane.

19 The TMDL, which is essentially a water quality cleanup plan, was a multi-year  
20 process that involved public and private entities that discharge wastewater into the Spokane  
21 River<sup>3</sup>, and many stakeholders, including Ecology, the United States Environmental

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<sup>3</sup> While Avista does not discharge into the Spokane River, Ecology, EPA, and others believe that the presence of the Long Lake Hydroelectric Facility increases the opportunity for algae growth. Algae absorbs oxygen when it decomposes.

1 Protection Agency (“EPA”), Washington Department of Fish and Wildlife, Idaho  
2 Department of Environmental Quality, Native American tribes and other parties. The  
3 TMDL process was ongoing when FERC issued the Project License in 2009 for the Spokane  
4 River Project.

5 The 2009 FERC Project License incorporated in its Appendix B the conditions of  
6 Washington State’s Water Quality Section 401 Certification (“401 Certification”) as  
7 mandatory conditions under the authority of the Clean Water Act, consistent with the  
8 Federal Power Act. Condition 5.6C relates to dissolved oxygen in Lake Spokane. The 401  
9 Certification and FERC License require Avista to develop a Water Quality Attainment Plan  
10 (“Attainment Plan”) to “improve oxygen conditions in Lake Spokane....sufficient to address  
11 its proportional level of responsibility, based on its contribution to the dissolved oxygen  
12 problem in the Lake.” Condition 5.6C requires that the Attainment Plan be implemented  
13 over a 10-year period, with the potential of “alternative action[s]” being required should the  
14 Plan’s results be insufficient after the initial 10-year period.

15 At the time the 401 Certification and FERC License were issued, the TMDL process  
16 was still ongoing, so Condition 5.6C served essentially as a placeholder until such time as  
17 the TMDL was completed.

18 The TMDL process continued subsequent to the issuance of the FERC License for  
19 Avista’s Spokane River projects. In the TMDL discussions and negotiations, many  
20 stakeholders, including Department of Ecology staff, sought to require Avista to oxygenate  
21 or aerate Lake Spokane as a means to address low dissolved oxygen levels. Avista, for its  
22 part, was actively engaged in the TMDL process both to ensure that the determination of  
23 Avista’s proportionate responsibility for the impairment issue was not overstated, as well as

1 to promote alternatives to the oxygenation or aeration capital project. The suggested  
2 alternatives would serve to provide for long-term benefits to the Spokane River and Lake  
3 Spokane at a lower cost to the Company and its customers.

4 In early 2012, Ecology issued the final TMDL. As the TMDL was now complete,  
5 Condition 5.6C of the Section 401 Certification was amended, as was the 2009 FERC  
6 license. The issuance of the TMDL and FERC License amendment also started Avista's  
7 timeline for developing and submitting the Attainment Plan to Ecology. Avista developed  
8 the Attainment Plan in consultation with Ecology and, after Ecology's approval, submitted it  
9 to FERC for approval in October 2012. FERC subsequently approved the Attainment Plan.

10 As was discussed earlier, Avista actively participated in the TMDL process. In the  
11 final TMDL, the methodology for how Avista should address the low dissolved oxygen  
12 levels in Lake Spokane was left open for exploration in the Attainment Plan (i.e, it was not  
13 prescriptive in how Avista must address the issue). One of the methodologies to address this  
14 problem was to aerate or oxygenate the Lake. Such a facility would have either used  
15 trucked in liquid oxygen or ambient air, bubbled or pressurized respectively, through an  
16 extensive distribution system installed through much of the 23-mile long lake. Avista had  
17 estimated this project could have cost up to \$8.0 million dollars to model, design and  
18 construct (not including additional property rights that may have been required), plus an  
19 additional \$200,000 to \$300,000 per year in ongoing operations and maintenance, including  
20 liquid oxygen delivery and use.

21 Through extensive modeling efforts, and through ongoing negotiation over a period  
22 of several years through the TMDL process, Avista was able to avoid the construction of an  
23 aeration facility. While Avista could have chosen to move forward with the more expensive

1 capital project to address oxygen levels, the Company's additional efforts in evaluating  
2 alternatives resulted in the opportunity to choose a solution that is much less expensive for  
3 customers. Alternatively, Avista developed a 10-year implementation plan under which  
4 Avista is undertaking a number of smaller-scale efforts, including such items as removing  
5 non-native carp, removing non-native aquatic vegetation, educating shoreline landowners on  
6 proper vegetation management, and a number of other elements.

7 **Q. Please explain the costs incurred by the Company to study the total**  
8 **dissolved gas downstream of Long Lake Dam, and the Company's proposal for**  
9 **recovering these costs.**

10 A. Through December 31, 2012, the Company had incurred \$1.340 million of  
11 system costs related to meeting certain regulatory requirements to improve the dissolved  
12 oxygen levels in Lake Spokane, as described above. Washington's share of these costs was  
13 approximately \$871,000.<sup>4</sup> As described by witness Ms. Andrews, through this general rate  
14 case filing, the Company is seeking a prudence finding related to these costs, and  
15 amortization of the TDG costs for Lake Spokane over a three-year period beginning in 2015.

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

17 A. Yes it does.

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<sup>4</sup> In Docket No. UE-131576 the Company sought, and received approval of (see Order No. 01), an Accounting Order to defer the costs related to the improvement of dissolved oxygen levels in Lake Spokane. Order No. 01 authorized the Company to defer and transfer Washington's share of these costs (approximately \$871,000) to FERC account 182.3. The Order also approved Avista's proposal for recovery and prudence of these costs to be determined in its next general rate case or in a separate filing.