

Exhibit No. \_\_\_\_ (DCG-24)  
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, Before the Idaho Public Utilities  
Commission, Case No. AVU-E-15-05  
(Provided on CD)*

July 27, 2015

DAVID J. MEYER  
VICE PRESIDENT AND CHIEF COUNSEL FOR  
REGULATORY & GOVERNMENTAL AFFAIRS  
AVISTA CORPORATION  
P.O. BOX 3727  
1411 EAST MISSION AVENUE  
SPOKANE, WASHINGTON 99220-3727  
TELEPHONE: (509) 495-4316  
FACSIMILE: (509) 495-8851  
DAVID.MEYER@AVISTACORP.COM

**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

IN THE MATTER OF THE APPLICATION ) CASE NO. AVU-E-15-05  
OF AVISTA CORPORATION FOR THE )  
AUTHORITY TO INCREASE ITS RATES )  
AND CHARGES FOR ELECTRIC AND )  
NATURAL GAS SERVICE TO ELECTRIC ) DIRECT TESTIMONY  
AND NATURAL GAS CUSTOMERS IN THE ) OF  
STATE OF IDAHO ) SCOTT J. KINNEY  
)

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

1 I. INTRODUCTION

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

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

7 Q. Would you briefly describe your educational and  
8 professional background?

9 A. Yes. I graduated from Gonzaga University in  
10 1991 with a B.S. in Electrical Engineering and I am a  
11 licensed Professional Engineer in the State of Washington.  
12 I joined the Company in 1999 after spending eight years  
13 with the Bonneville Power Administration. I have held  
14 several different positions at Avista in the Transmission  
15 Department, beginning as a Senior Transmission Planning  
16 Engineer. In 2002, I moved to the System Operations  
17 Department as a Supervisor and Support Engineer. In 2004,  
18 I was appointed as the Chief Engineer, System Operations  
19 and as the Director of Transmission Operations in June  
20 2008. I became the Director of Power Supply in January  
21 2013, where my primary responsibilities involve management  
22 and oversight of short- and long-term planning and  
23 acquisition of power resources.

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

3           A. My testimony provides an overview of Avista's  
4 resource planning and power supply operations. This  
5 includes summaries of the Company's generation resources,  
6 the current and future load and resource position, and  
7 future resource plans. As part of an overview of the  
8 Company's risk management policy, I will provide an update  
9 on the Company's hedging practices. I will address  
10 hydroelectric and thermal project upgrades, followed by an  
11 update on recent developments regarding hydro licensing.

12           Company witness Ms. Andrews incorporated Idaho's  
13 share of the capital additions (2015 through 2017)  
14 described in my testimony.

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

Description	Page
I. Introduction	1
II. Resource Planning and Power Operations	3
III. Generation Capital Projects	13
IV. Hydro Relicensing	20

21  
22           **Q. Are you sponsoring any Exhibits?**

23           A. Yes. I am sponsoring Exhibit 4, Schedules 1  
24 through 3. Schedule 1 includes Avista's 2013 Electric  
25 Integrated Resource Plan and Appendices, and Schedule 2

1 provides the 2013 IRP forecast of the Company's load and  
2 resource positions from 2014 through 2033. Confidential  
3 Schedule 3C includes Avista's Energy Resources Risk  
4 Policy.

5

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

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

9 A. Yes. Avista's owned generating resource  
10 portfolio includes hydroelectric generation projects,  
11 base-load coal and base-load natural gas-fired thermal  
12 generation facilities, waste wood-fired generation, and  
13 natural gas-fired peaking generation. Avista-owned  
14 generation facilities have a total capability of 1,851 MW,  
15 which includes 58% hydroelectric and 42% thermal  
16 resources.

17 Illustration Nos. 1 and 2 below summarize the present  
18 net capability of Avista's hydroelectric and thermal  
19 generation resources:

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

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>

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

Project Name	Fuel Type	Start Date	Winter Maximum Capacity (MW)	Sumer 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 power supply contracts?

A. Yes. Avista's contracted-for generation resource portfolio consists of Mid-Columbia hydroelectric, PURPA, a tolling agreement for a natural gas-fired

1 combined cycle generator, and a contract with a wind  
2 generation facility.

3 The Company currently has long-term contractual  
4 rights for resources owned and operated by the Public  
5 Utility Districts of Chelan, Douglas and Grant counties.  
6 Illustration No. 3 below provides details about the Mid-  
7 Columbia hydroelectric contracts. The Rocky Reach and  
8 Rock Island contracts with Chelan PUD expired in December  
9 2014, but the Company signed a one year agreement for 4  
10 percent of Chelan PUD's Rocky Reach and Rock Island  
11 hydroelectric output in 2015. The Company was also  
12 recently awarded a 5 percent slice of Chelan PUD's Rocky  
13 Reach and Rock Island hydro output for 2016 through 2020  
14 through a competitive bidding process. Additional details  
15 are provided in witness Mr. Johnson's testimony.  
16 Illustration No. 4 provides details about other contracts  
17 currently in place.

18 Avista also has a long-term power purchase agreement  
19 (PPA) in place through October 2026 entitling the Company  
20 to dispatch, purchase fuel for, and receive the power  
21 output from, the Lancaster combined-cycle combustion  
22 turbine project located in Rathdrum, Idaho. In 2011, the  
23 Company executed a 30-year power purchase agreement to  
24 purchase the output (105 MW peak) and all environmental

1 attributes from the Palouse Wind, LLC wind generation  
2 project that began commercial operation in December 2012.  
3 The Company's contract with the Stateline Wind facility  
4 terminated in March 2014, and the contract to sell energy  
5 and associated environmental attributes with the  
6 Sacramento Municipal Utility District ended in December  
7 2014.

8 **Illustration No. 3: Mid-Columbia Hydroelectric Capacity**  
9 **and Energy Contracts<sup>1</sup>**  
10

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	4.0	1/2015	12/2015	46.5	14.7
Chelan PUD – Rock Island	4.0	1/2015	12/2015	16.1	20.5
Douglas PUD - Wells	3.3	2/1965	8/2018	27.9	14.7
Canadian Entitlement <sup>1</sup>				-8.1	-4.6
<b>2015 Total Net Contracted Capacity and Energy</b>				<b>141.6</b>	<b>79.9</b>

16  
<sup>1</sup> Under the Columbia River Treaty signed in 1961 and the Pacific Northwest Coordination Agreement (PNCA) signed in 1964, Canada receives return energy (Canadian Entitlement) related to storage water in upstream reservoirs for coordinated flood control and power generation optimization.



**Illustration No. 4: Other Contractual Rights and Obligations Through 2015**

<b>Contract</b>	<b>Type</b>	<b>Fuel Source</b>	<b>End Date</b>	<b>Winter Capacity (MW)</b>	<b>Summer Capacity (MW)</b>	<b>Annual Energy (aMW)</b>
<b>Energy America, LLC *</b>	Sale	Various	12/2019	-35	-50	-42.5
<b>PGE Capacity Exchange</b>	Exchange	System	12/2016	-150	-150	0
<b>Douglas Settlement</b>	Purchase	Hydro	9/2018	2	2	3
<b>WNP-3</b>	Purchase	System	6/2019	82	0	42
<b>Lancaster</b>	Purchase	Gas	10/2026	290	249	222
<b>Palouse Wind</b>	Purchase	Wind	12/2042	0	0	40
<b>Nichols Pumping</b>	Sale	System	10/2018	-6.8	-6.8	-6.8
<b>PURPA Contracts</b>	Purchase	Varies	Varies	47.6	47.6	28.8
<b>Total</b>				<b>229.8</b>	<b>91.8</b>	<b>286.5</b>

\*Energy America contracts start July 1, 2015 and includes 42.5 aMW energy plus REC's, 2016-2018 includes 50 aMW energy plus REC's and 2019 includes 20 aMW energy plus REC's.

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

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

1 demand-side management (DSM), and long-term contract  
2 purchases. Resource acquisitions typically include a  
3 Request for Proposals (RFP) and/or other market due  
4 diligence processes.

5 **Q. Please summarize Avista's load and resource**  
6 **position.**

7 A. Avista's 2013 IRP shows forecasted annual energy  
8 deficits beginning in 2026, and sustained annual capacity  
9 deficits beginning in 2020.<sup>2</sup> These capacity and energy  
10 load/resource positions are shown on pages 2-39 through 2-  
11 41 of Schedule 1. Schedule 2 shows the 2013 IRP load and  
12 resource projection. Avista's IRP projection shows an  
13 annual energy deficit beginning in 2026 of about 19 aMW,  
14 and increasing to a 284 aMW deficit in 2033. The  
15 Company's January capacity resource position, based on an  
16 18-hour peak event (6 hours per day and over 3 days), is  
17 projected to be surplus through 2019. Sustained annual  
18 capacity deficiencies, based on a January peak, begin at  
19 42 MW in 2020 and increase to a 551 MW deficit in 2033.  
20 The Company's August capacity resource position, based on  
21 an 18-hour peak event, is projected to be surplus through  
22 2023. Sustained annual capacity deficiencies, based on an

<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 August peak, begin at 2 MW in 2024 and increase to a 361  
2 MW deficit in 2033.

3 The Company's updated load and resource position will  
4 be included with the submission of the 2015 Electric IRP  
5 in August 2015.

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

8 A. The Company is currently guided by the 2013  
9 Preferred Resource Strategy (PRS). The current PRS is  
10 described in the 2013 Electric IRP, which is attached as  
11 Schedule 1 of Exhibit No. 4. The IRP provides details  
12 about future resource needs, specific resource costs,  
13 resource-operating characteristics, and the scenarios used  
14 for evaluating the mix of resources for the PRS. The  
15 Commission acknowledged the 2013 Electric IRP in Case No.  
16 AVU-E-13-07 on March 20, 2014 in Order No. 32997. The IRP  
17 represents the preferred plan at a point in time; however,  
18 Avista continues evaluating resource options to meet  
19 future load requirements and is currently working on its  
20 next IRP, which will be filed in August 2015. The Company  
21 has held five of six scheduled TAC meetings and is  
22 currently finalizing the PRS and completing scenario  
23 analysis.

1 Avista's 2013 PRS includes less than one MW of  
2 distribution efficiencies, 221 MWS of cumulative energy  
3 efficiency, 19 MWS of demand response, 6 MWS of upgrades  
4 to existing thermal plants, and 569 MWS of natural gas-  
5 fired plants (299 MWS of simple cycle combustion turbines  
6 (SCCT) and 270 MWS of combined-cycle combustion turbine  
7 (CCCT)). The timing and type of these resources as  
8 published in the 2013 IRP is provided in Illustration No.  
9 5. The Company's draft 2015 PRS does not deviate  
10 significantly from the 2013 PRS.

11 **Illustration No. 5: 2013 Electric IRP Preferred Resource**  
12 **Strategy**  
13

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>		575	529
Efficiency Improvements	By the End of Year	Peak Reduction (MW)	Energy (aMW)
Energy Efficiency	2014-2033	221	164
Demand Response	2022-2027	19	0
Distribution Efficiencies	2014-2017	<1	<1
<b>Total Efficiency</b>		240	164

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

23 A. Yes. Avista Utilities uses several techniques  
24 to manage the risks associated with serving load and  
25 managing Company-owned and controlled resources. The

1 Energy Resources Risk Policy, which is attached as  
2 Confidential Schedule 3C of Exhibit No. 4, provides  
3 general guidance to manage the Company's energy risk  
4 exposure relating to electric power and natural gas  
5 resources over the long-term (more than 41 months), the  
6 short-term (monthly and quarterly periods up to  
7 approximately 41 months), and the immediate term (present  
8 month).

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

18 Avista aims to develop or acquire long-term energy  
19 resources based on the IRP's PRS, while taking advantage  
20 of competitive opportunities to satisfy electric resource  
21 supply needs in the long-term period. Electric power and  
22 natural gas fuel transactions in the immediate term are  
23 driven by a combination of factors that incorporate both  
24 economics and operations, including near-term market

1 conditions (price and liquidity), generation economics,  
2 project license requirements, load and generation  
3 variability, reliability considerations, and other near-  
4 term operational factors.

5 For the short-term timeframe, which falls between the  
6 long-term and immediate term periods, the Company's Energy  
7 Resources Risk Policy guides its approach to hedging  
8 financially open forward positions. A financially open  
9 forward period position may be the result of either a  
10 short position situation, for which the Company has not  
11 yet purchased the fixed-price fuel to generate, or  
12 alternatively purchased fixed-price electric power from  
13 the market, to meet projected average load for the forward  
14 period. Or it may be a long position, for which the  
15 Company has generation above its expected average load  
16 needs, and has not yet made a fixed-price sale of that  
17 surplus to the market in order to balance resources and  
18 loads.

19 The Company employs an Electric Hedging Plan to guide  
20 power supply position management in the short-term period.  
21 The Risk Policy Electric Hedging Plan is essentially a  
22 price diversification approach employing a layering  
23 strategy for forward purchases and sales of either natural  
24 gas fuel for generation or electric power in order to

1 approach a generally balanced position against expected  
2 load as forward periods draw nearer.

3

4

**III. GENERATION CAPITAL PROJECTS**

5 Q. Would you please provide a brief description of  
6 the generation-related capital projects planned for 2015,  
7 2016 and 2017?

8 A. Yes. As shown in Table No. 1 below, the total  
9 2015, 2016 and 2017 generation capital projects to be  
10 completed total \$122.9 million, \$45.5 million, and \$83.7  
11 million, respectively, on a system basis. Details about  
12 the generation-related capital projects totaling \$252.2  
13 million are discussed below.

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15

<b>TABLE NO. 1</b>			
<b>Generation / Production Capital Projects (System)</b>			
<b>Business Case Name</b>	<b>2015 \$ (000's)</b>	<b>2016 \$ (000's)</b>	<b>2017 \$ (000's)</b>
Hydro - Base Load Hydro	\$ 1,974	\$ 1,149	\$ 1,149
Hydro - Clark Fork Settlement Agreement	13,988	6,054	22,836
Hydro - Generation Battery Replacement	434	250	250
Hydro - Hydro Safety Minor Blanket	151	75	80
Hydro - Little Falls Plant Upgrade	14,300	9,000	10,000
Hydro - Nine Mile Rehab	56,567	9,871	858
Hydro - Regulating Hydro	5,186	3,533	3,533
Hydro - Spokane River License Implementation	1,266	397	17,018
Other - Base Load Thermal Plant	2,200	2,200	2,201
Other - Peaking Generation	501	500	500
Thermal - Kettle Falls Water Supply	1,529	-	-
Thermal - Colstrip Thermal Capital	2,497	10,480	9,617
Other - Coyote Springs LTSA	-	2,000	730
Hydro - Noxon Spare Coils	1,350	-	-
Hydro - Post Falls South Channel Replacement	9,309	-	-
Hydro - Cabinet Gorge Unit 1 Refurbishment	11,687	-	-
Cabinet Gorge Automation Replacement	-	-	2,842
Kettle Falls Stator Rewind	-	-	7,930
Long Lake Replace Field Windings	-	-	4,172
	<b>\$ 122,939</b>	<b>\$ 45,509</b>	<b>\$ 83,716</b>

16  
17  
18  
19  
20  
21  
22  
23  
24  
25  
26  
27  
28  
29  
30  
31  
32

**Base Load Hydro: 2015: \$1,974,000; 2016: \$1,149,000; 2017: \$1,149,000**

This program covers the capital maintenance expenditures required to keep Avista's Upper Spokane River hydroelectric plants operating within 90% of their current performance, assuming some degradation of performance over time. The plants covered in this program include Post Falls, Upper Falls, Monroe Street, and Nine Mile. The program focuses on ways to maintain compliance and reduce overall operations and maintenance expenses while maintaining a reasonable unit availability through a programmatic approach, rather than reacting to problems as they develop. The historical availability for the base load hydro plants has been declining over the past decade due to deteriorating equipment and a need to replace some equipment and systems that are as much as 100 years old.



1 **Clark Fork Settlement Agreement - 2015: \$13,988,000; 2016:**  
2 **\$6,054,000; 2017: \$22,836,000**

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

26  
27 **Generation Battery Replacement - 2015: \$434,000; 2016:**  
28 **\$250,000; 2017: \$250,000**

29 This program is based on an asset management plan for the  
30 station batteries in all generating stations. This item  
31 will also have some minor fluctuations as the number and  
32 size of batteries in any particular year can change.

33  
34 **Hydro Safety Minor Blanket - 2015: \$151,000; 2016:**  
35 **\$75,000; 2017: \$80,000**

36 This item funds periodic capital purchases and projects to  
37 ensure public safety at hydro facilities, on and off  
38 water, in the context of FERC regulatory and license  
39 requirements.

40 **Little Falls Plant Upgrade- 2015: \$14,300,000; 2016:**  
41 **\$9,000,000; 2017: \$10,000,000**

42 The existing Little Falls equipment ranges in age from 60  
43 to more than 100 years old. Forced outages at Little  
44 Falls because of equipment failures have significantly  
45 increased over the past six years, from about 20 hours in  
46 2004 to several hundred hours in the past three to four

1 years. This project will replace nearly all of the older,  
2 unreliable equipment with new equipment. This project  
3 includes replacing two of the turbines, all four  
4 generators, all generator breakers, three of the four  
5 governors, all of the automatic voltage regulators,  
6 removing all four generator exciters, replacing the unit  
7 controls, changing the switchyard configuration, replacing  
8 the unit protection system, and replacing and modernizing  
9 the station service.

10  
11 **Nine Mile Rehabilitation - 2015: \$56,567,000; 2016:**  
12 **\$9,871,000; 2017: \$858,000**

13 This capital program is necessary to rehabilitate and  
14 modernize the four unit Nine Mile HED. The program  
15 includes projects to replace the existing 3 MW Units 1 and  
16 2, which are more than 100 years old and worn out, with  
17 two new 8 MW generators/turbines. The new units will add  
18 1.4 aMW of energy beyond the original configuration and  
19 6.4 MW of capacity above current generation levels.<sup>3</sup> In  
20 addition to these capacity upgrades, the Nine Mile  
21 facility will receive upgrades to the following:

- 22 • hydraulic governors;
- 23 • static excitation system;
- 24 • switchgear;
- 25 • station service;
- 26 • control and protection packages;
- 27 • ventilation upgrades;
- 28 • rehabilitation of intake gates and sediment bypass
- 29 system;
- 30 • a new warehouse will be constructed;
- 31 • new tail race gate system will be added;
- 32 • new grounding and communications will be added;
- 33 • a barge landing will be added;
- 34 • a cottage will be removed and another remodeled;
- 35 • a new panel room will be added;
- 36 • Units 3 and 4 will be overhauled and modernized;
- 37 • the powerhouse will be restored;
- 38 • new access gates and controls will be added; and

<sup>3</sup>The additional output above the current generation has been included in the AURORAXMP power cost model reflecting the benefit of this project.

1       • other improvements will be made.

2  
3       **Regulating Hydro - 2015: \$5,186,000; 2016: \$3,533,000;**  
4       **2017: \$3,533,000**

5       This program covers the capital maintenance expenditures  
6       required to keep the Long Lake, Little Falls, Noxon Rapids  
7       and Cabinet Gorge plants operating at their current  
8       performance levels. The program will work to improve the  
9       reliability of these plants so that their value can be  
10      maximized in both the energy and ancillary markets.

11  
12      **Spokane River Implementation PM&E - 2015: \$1,266,000;**  
13      **2016: \$397,000; 2017: \$17,018,000**

14      This category covers the implementation of Protection,  
15      Mitigation and Enhancement (PM&E) programs related to the  
16      FERC License for the Spokane River. This includes items  
17      enforceable by FERC, mandatory conditioning agencies, and  
18      through settlement agreements. Additional details  
19      concerning the PM&E measures for the Spokane River license  
20      are included in the hydro relicensing section that  
21      follows.

22  
23      **Base Load Thermal Plant - 2015: \$2,200,000; 2016:**  
24      **\$2,200,000; 2017: \$2,201,000**

25      This program is necessary to sustain or improve the  
26      existing operating costs of base load thermal generating  
27      stations, including Coyote Springs 2, Colstrip, Kettle  
28      Falls, and Lancaster. Capital projects include  
29      replacement of items identified through asset management  
30      decisions and programs necessary to maintain reliable and  
31      low operating costs of these plants. As this program  
32      proceeds, it is expected that forced outage rates and  
33      forced deratings of these facilities will decrease to a  
34      level one standard deviation less than the current  
35      average, resulting in more economic benefits of the  
36      project.

37  
38      **Peaking Generation - 2015: \$501,000; 2016: \$500,000; 2017:**  
39      **\$500,000**

40      This program covers the capital maintenance expenditures  
41      required to keep the natural gas-fired peaking units  
42      (Boulder Park, Rathdrum CT, and Northeast CT) operating at  
43      or above their current performance levels. The program  
44      focuses on maximizing the ability of these units to start  
45      and run when demanded (starting reliability).

46

1 **Kettle Falls Water Supply- 2015: \$1,529,000**

2 The Kettle Falls Generation Plant receives its water from  
3 the City of Kettle Falls from an agreement that dates back  
4 to the construction of the plant in the early 1980s. This  
5 effort is to secure necessary water rights and a long term  
6 water supply for the plant that is controlled by the  
7 company.  
8

9 **Colstrip Thermal Capital - 2015: \$2,497,000; 2016:**  
10 **\$10,480,000; 2017: \$9,617,000**

11 This program includes ongoing capital expenditures  
12 associated with normal outage activities on Units 3 & 4 at  
13 Colstrip. Every two out of three years, there are planned  
14 outages at Colstrip with higher capital program  
15 activities. For non-outage years, the program activities  
16 are reduced. Avista votes its 15 percent share of Units 3  
17 & 4 and its approximate 10 percent share of common  
18 facilities to approve or disapprove of the budget proposed  
19 by Pacific Pennsylvania Light Montana (PPLM) on behalf of  
20 all the owners.  
21

22 **Coyote Springs 2 LTSA Capital Addition - 2016: \$2,000,000;**  
23 **2017: \$730,000**

24 This program covers the capital accruals required to  
25 execute our Long Term Service Agreement (LTSA) with  
26 General Electric for Coyote Springs Unit 2. This program  
27 will have fluctuations to account for the variable  
28 operating hours and operating conditions that feed into  
29 the LTSA formula.  
30

31 **Noxon Spare Coils - 2015: \$1,350,000**

32 This project is to replace the spare coils that were used  
33 in the Spring of 2013 to repair the stator winding that  
34 failed for Unit 4. This item will procure 100 spare  
35 coils. These spares cover Units 1 through 4 (Unit 5 uses  
36 different coils). Because Avista had spares available,  
37 Unit 4 was able to return to normal service within 11  
38 weeks. Without these spares, the unit would have been out  
39 for nine months or more. Prices for coils supplied under  
40 emergency conditions would likely carry a 30 percent cost  
41 premium. This project does not include any installation,  
42 only the replacement of previously held stock.  
43

44 **Post Falls South Channel Gate Replacement - 2015:**  
45 **\$9,309,000**

46 Avista is in the process of refurbishing the south channel  
47 gates to comply with FERC Dam Safety directives. The

1 project entails removing most of the existing concrete  
2 structure and replacing it with a new concrete structure,  
3 new spillway gates, and new hoist systems to automate gate  
4 operation.

5  
6 **Cabinet Gorge Unit 1 Refurbishment - 2015: \$11,687,000**

7 This is the capital portion of a major overhaul project  
8 planned for Cabinet Gorge Unit #1. The runner hub has  
9 significant mechanical issues and needs to be replaced to  
10 allow for frequent cycling for load following. The present  
11 automatic voltage regulator provides a relatively slow  
12 response due to its hybrid design and has no limiters for  
13 generator protection. A new system will provide faster  
14 response and add limiters. The machine monitoring is to  
15 allow for better analysis of machine condition for this  
16 important unit. Rehabilitation of this unit will also  
17 allow flexibility around minimum flow for fish habitat.

18  
19 **Cabinet Gorge Automation Replacement - 2017: \$2,842,000**

20 This project is to replace the unit and station service  
21 control equipment at Cabinet Gorge with a system  
22 compatible with Avista's current standards. The Bailey  
23 Net 90 equipment that is installed currently is obsolete  
24 because replacement of the system can only be done through  
25 secondary and salvage markets. In addition, the current  
26 system does not provide enough inputs and outputs that  
27 allow implementation of standard unit control and  
28 monitoring schemes. This work will replace the existing  
29 panel and control systems with a new system. The scope of  
30 work has expanded to include replacement governors,  
31 voltage regulators, and protective relays.

32  
33 **Kettle Falls Stator Rewind - 2017: \$7,930,000**

34 The Kettle Falls generator is over 32 years old and is at  
35 the end of its expected life. This project consists of  
36 monitoring the existing machine, developing rewind  
37 contract, manufacturing replacement coils, disassembly,  
38 coil removal, new coil installation, reassembly, startup,  
39 testing and commissioning. Consequences of failure  
40 include an unscheduled outage with lost generation, loss  
41 of renewable energy credits, long term interruption of  
42 fuel supply, collateral damage to core and hydrogen  
43 cooling with resulting safety hazards.

44  
45 **Long Lake Replace Field Windings - 2017: \$4,172,000**

46 Over the past 10 years, the Company has observed a  
47 continuing decline in the insulation level on the

1 generators at Long Lake as measured using Megger test  
2 instruments. Long Lake has experienced an increasing  
3 amount of forced outages and down time due to the  
4 deteriorating condition of these units.  
5

6 **IV. HYDRO RELICENSING**

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

10 A. Yes. Avista received a new 45-year FERC  
11 operating license for its Cabinet Gorge and Noxon Rapids  
12 hydroelectric generating facilities on the Clark Fork  
13 River on March 1, 2001. The Company has continued to work  
14 with the 27 Clark Fork Settlement Agreement signatories to  
15 meet the goals, terms, and conditions of the Protection,  
16 Mitigation and Enhancement (PM&E) measures under the  
17 license. The implementation program, in coordination with  
18 the Management Committee which oversees the collaborative  
19 effort, has resulted in the protection of approximately  
20 80,000 acres of bull trout, wetlands, uplands, and  
21 riparian habitat. More than 37 individual stream habitat  
22 restoration projects have occurred on 23 different  
23 tributaries within our project area. Avista has collected  
24 data on almost 19,000 individual bull trout within the  
25 project area. The upstream fish passage program, using  
26 electrofishing, trapping and hook-and-line capture

1 efforts, has reestablished bull trout connectivity between  
2 Lake Pend Oreille and the Clark Fork River tributaries  
3 above Cabinet Gorge and Noxon Rapids Dams through the  
4 upstream transport of 498 adult bull trout, with over 160  
5 of these radio tagged and their movements studied. Avista  
6 has worked with the U.S. Fish and Wildlife Service to  
7 develop and test two experimental fish passage facilities.  
8 Avista, in consultation with certain state and federal  
9 agencies, is currently developing designs for a permanent  
10 upstream adult fishway for Cabinet Gorge and Noxon Rapids.  
11 In 2013, designs for the Cabinet Gorge Fishway Fish  
12 Handling and Holding Facility were completed and  
13 construction began in 2013. A permanent tributary trap on  
14 Graves Creek (an important bull trout spawning tributary)  
15 was constructed in 2012 and testing began 2013. A three-  
16 year evaluation process is ongoing to determine if future  
17 permanent tributary traps are warranted.

18 Recreation facility improvements have been made to  
19 over 28 sites along the reservoirs. Avista also owns and  
20 manages over 100 miles of shoreline that includes 3,500  
21 acres of property to meet FERC required natural resource  
22 goals, while allowing for public use of these lands where  
23 appropriate.

1           Finally, tribal members continue to monitor known  
2 cultural and historic resources located within the project  
3 boundary to ensure that these sites are appropriately  
4 protected and are working to develop interpretive sites  
5 within the project.

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

9           A.    Yes.    How best to deal with total dissolved gas  
10 (TDG) levels occurring during spill periods at Cabinet  
11 Gorge Dam was unresolved when the current Clark Fork  
12 license was received.    The license provided time to study  
13 the actual biological impacts of dissolved gas and to  
14 subsequently develop a dissolved gas mitigation plan.  
15 Stakeholders, through the Management Committee, ultimately  
16 concluded that dissolved gas levels should be mitigated,  
17 in accordance with federal and state laws.    A plan to  
18 reduce dissolved gas levels was developed with all  
19 stakeholders, including the Idaho Department of  
20 Environmental Quality.    The original plan called for the  
21 modification of two existing diversion tunnels, which  
22 could redirect stream flows exceeding turbine capacity  
23 away from the spillway.



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

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

16           FERC approved the GSCP addendum in February 2010 and  
17 in April 2010 the Gas Supersaturation Subcommittee (a  
18 subcommittee of the MC) chose five TDG abatement  
19 alternatives for feasibility studies. Feasibility studies  
20 and preliminary design were completed on two of the  
21 alternatives in 2012. Final design, construction, and  
22 testing of the spillway crest modification prototype was  
23 completed in 2013. Test results indicated over all TDG  
24 performance was positive, however, additional

1 modifications were required to address cavitation issues.  
2 Modification of the spillway crest prototype and retesting  
3 were completed in 2014. It is anticipated that up to seven  
4 additional spillway crests will be modified by 2018.

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

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

22 Since 2011, Avista has implemented water quality,  
23 fisheries, recreation, cultural, erosion, wetland, aquatic  
24 weed management, aesthetic, operational and related

1 conditions across all five hydro developments under the  
2 Protection Mitigation and Enhancement (PM&E) measures.  
3 The majority of the PM&E measures are on-going in nature,  
4 however, a number are one-time improvements, such as the  
5 Upper Falls aesthetic spill project located in downtown  
6 Spokane. Six hundred and fifty six acres of wetland  
7 mitigation properties were acquired in 2011 and 2012 on  
8 Upper Hangman Creek in Idaho for the Coeur d'Alene Tribe  
9 through the Coeur d'Alene Reservation Trust Resources  
10 Restoration Fund that Avista established in 2009. The  
11 Company developed wetland restoration plans for  
12 approximately 500 of the required 1,368 replacement acres  
13 of wetland and riparian habitat and is waiting for  
14 approval by the U.S. Department of Interior, Bureau of  
15 Indian Affairs to continue implementing the plans. The  
16 U.S. Department of Interior, Bureau of Indian Affairs and  
17 FERC approved revisions, requested by the Coeur d'Alene  
18 Tribe, to the Coeur d'Alene Reservation Erosion Control  
19 Implementation Plan. The revisions allow Avista and the  
20 Tribe to acquire, restore, manage, and monitor 56 acres of  
21 land consistent with the requirements of the Wetland and  
22 Riparian Habitat Plan, mentioned above, in lieu of  
23 implementing shoreline stabilization along 63,130 feet of  
24 the Lower St. Joe River. The new total for all replacement

1 lands is now 1,424 acres. In 2014, the Company monitored  
2 the vegetation on the recently completed 124-acre wetland  
3 mitigation project along the St. Joe River and will be  
4 responsible for maintaining approximately half of it,  
5 which lies on Avista's property, for the License term.

6 Avista continued work with the various local, state,  
7 and federal agencies to complete more of the required  
8 recreation projects in Idaho, such as trail and  
9 interpretive sign improvements in Post Falls, and public  
10 recreation improvements along the St. Maries River. In  
11 Washington, the Company completed the ten boat-in-only  
12 campsites on Lake Spokane, and a new carry-in-only boat  
13 launch at Nine Mile Falls. The Company developed and is  
14 implementing the management plan for the recently  
15 purchased 109 acre Sacheen Springs Wetland Complex located  
16 along the Little Spokane River. In 2015, Avista will  
17 continue to develop and implement local, state, and  
18 federally required work plans to fulfill License  
19 conditions.

20 A number of the approved work plans required the  
21 Company to conduct extensive studies to determine  
22 appropriate measures to mitigate resource impacts. The  
23 more significant studies and mitigation measures include  
24 those for total dissolved gas (TDG) downstream of Long

1 Lake Dam. Avista modeled several different types of  
2 spillway modifications between 2011 and 2013 and completed  
3 the design for the desired deflector configurations in  
4 2014. Following the design, Avista requested a one-year  
5 setback in the construction schedule to allow completing  
6 of the construction process in 2016-2017 instead of 2015-  
7 2016. The new schedule will allow the Company to complete  
8 work on the dam's spillway gate seals and the rigorous  
9 permitting processes prior to constructing the new  
10 deflectors. The Company completed the proposed dissolved  
11 oxygen (DO) measure in the tailrace below Long Lake Dam  
12 and is continuing to monitor its effectiveness in  
13 addressing low DO in the river below the dam. Avista is  
14 also continuing to evaluate potential measures to improve  
15 DO in Lake Spokane, the reservoir created by the Long Lake  
16 Dam. Cost estimates to construct the TDG spillway  
17 deflectors range between \$8.0 and \$10.0 million, and  
18 between \$2.5 and \$8.0 million to address DO in Lake  
19 Spokane. These estimates will be refined as the  
20 evaluations and studies are completed.

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

1           A.    Through December 31, 2012, the Company had  
2 incurred \$1.340 million of system costs related to meeting  
3 certain regulatory requirements to improve the dissolved  
4 oxygen levels in Lake Spokane, as described above.  
5 Idaho's share of these costs was approximately \$473,000.  
6 As described by Ms. Andrews, through this general rate  
7 case filing, the Company is seeking a prudence finding  
8 related to these costs, and amortization of the TDG costs  
9 for Lake Spokane over a two-year period beginning in 2016<sup>4</sup>.

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

12           A.    Yes it does.

<sup>4</sup> As explained by Ms. Andrews, the Company was authorized in Case No. AVU-E-13-06 (see Order No. 32917) to defer these costs in FERC Account 182.3 without a carrying charge, with a prudency review to occur in the Company's next general rate case or other proceeding.