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-16-03
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	DIRECT TESTIMONY
TO ELECTRIC CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	SCOTT J. KINNEY
	)	

FOR AVISTA CORPORATION

(ELECTRIC)

I. INTRODUCTION

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

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

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

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

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

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

As explained by Company witness Ms. Andrews, the Company is basing its electric revenue increase requested in this case on its electric Pro Forma Study including Idaho's share of generation capital projects I have described later in my testimony.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exhibit No. 4, Schedule 1 includes Avista's 2015 Electric Integrated Resource Plan and Appendices, and Exhibit No. 4, Confidential Schedule 2C includes Avista's Energy Resources Risk Policy.

II. RESOURCE PLANNING AND POWER OPERATIONS

Q. Would you please provide an overview of Avista's owned-generating resources?

A. Yes. Avista's owned generating resource portfolio includes a mix of hydroelectric generation projects, base-load coal and base-load natural gas-fired thermal generation facilities, waste wood-fired generation, and natural gas-fired peaking generation. Avista-owned generation facilities have a total capability of 1,925 MW, which includes 56% hydroelectric and 44% thermal resources.

Table Nos. 1 and 2 summarize the present net capability of Avista's hydroelectric and thermal generation resources:

Table 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	11.2
Post Falls	Spokane	14.8	18.0	9.4
Nine Mile	Spokane	36.0	32	15.7
Little Falls	Spokane	32.0	35.2	22.6
Long Lake	Spokane	81.6	89.0	56.0
Upper Falls	Spokane	10.0	10.2	7.3
Cabinet Gorge	Clark Fork	265.2	270.5	123.6
Noxon Rapids	Clark Fork	518.0	610.0	195.6
Total Hydroelectric		**972.4**	**1,079.9**	**441.4**

Table 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	176.0	130.0	166.5
Northeast	Gas	1978	66.0	42.0	61.2
Boulder Park	Gas	2002	24.6	24.6	24.6
Coyote Springs 2	Gas	2003	312.0	277.0	287.3
Kettle Falls	Wood	1983	47.0	47.0	50.7
Kettle Falls CT	Gas	2002	11.0	8.0	7.5
Total			**858.6**	**750.6**	**844.8**

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

The Company currently has long-term contractual rights for resources owned and operated by the Public Utility Districts of Chelan, Douglas and Grant counties. Table No. 3 provides the estimated energy and capacity associated with the Mid-Columbia hydroelectric contracts. Additional details on these contracts are presented in Company witness Mr. Johnson's testimony.

Table No. 4 provides details about other resource contracts. Avista 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 Lancaster combined-cycle combustion turbine project located in Rathdrum, Idaho. In 2011, the Company executed a 30-year power purchase agreement to purchase the output (105 MW peak) and all environmental attributes from the Palouse Wind, LLC wind generation project that began commercial operation in December 2012.

Table 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	36	19.5
Grant PUD – Wanapum	3.7	12/2001	12/2052	39	18.7
Chelan PUD – Rocky Reach	5.0	1/2016	12/2020	56.3	35.9
Chelan PUD – Rock Island	5.0	1/2016	12/2020	25	18.4
Douglas PUD - Wells	3.3	2/1965	8/2018	24	17.4
Canadian Entitlement[1]					**-3**
2015 Total Net Contracted Capacity and Energy				**180.3**	**106.9**

Table No. 4: Other Contractual Rights and Obligations

Contract	Type	Fuel Source	End Date	Winter Capacity (MW)	Summer Capacity (MW)	Annual Energy (aMW)
Energy America, LLC[2]	Sale	Various	12/2018	-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	47.6	47.6	28.8
Total				**214.8**	**91.8**	**279**

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

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

[2] Energy America, LLC sale is 50 aMW through 2018 and then decreases to 20 aMW in 2019.

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

Q. Please summarize Avista's load and resource position.

A. Avista's 2015 IRP shows forecasted annual energy deficits beginning in 2026, and sustained annual capacity deficits beginning in 2021.[3] These capacity and energy load/resource positions are shown on pages 6-9 through 6-12 of Exhibit No. 4, Schedule 1 and are also provided in Avista's 2015 IRP load and resource projection.

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[3] The Company has a 150 MW capacity exchange agreement with Portland General Electric that ends in December 2016 and Avista has short-term capacity deficits in 2016. Sustained annual capacity deficits begin in 2021.

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

A. The 2015 Preferred Resource Strategy (PRS) guides the Company's resource acquisitions. The current PRS is described in the 2015 Electric IRP, which is attached as Exhibit No. 4, Schedule 1. The IRP provides details about future resource needs, specific resource costs, resource-operating characteristics, and the scenarios used for evaluating the mix of resources for the PRS. The Commission acknowledged the 2015 Electric IRP in Case No. AVU-E-15-08 on February 4, 2016 in Order No. 33463. The IRP represents the preferred plan at a point in time; however, Avista continues evaluating different resource options to meet future load obligations. The Company will hold a Technical Advisory Committee meeting in the middle of 2016 to start the 2017 IRP effort.

Avista's 2015 PRS includes 193 MWs of cumulative energy efficiency, 41 MWs of upgrades to existing thermal plants, and 525 MWs of natural gas-fired plants (239 MWs of simple cycle combustion turbines (SCCT) and 286 MWs of combined-cycle combustion turbine (CCCT)). The timing and type of these resources as published in the 2015 IRP is provided in Table No. 5.

Table No. 5: 2015 Electric IRP Preferred Resource Strategy

Resource Type	By the End of	ISO Conditions	Winter Peak	Energy
Natural Gas Peaker	2020	96	102	89
Thermal Upgrades	2021-2025	38	38	35
Combined Cycle CT	2026	286	306	265
Natural Gas Peaker	2027	96	102	89
Thermal Upgrades	2033	3	3	3
Natural Gas Peaker	2034	47	47	43
Total		565	597	524
Efficiency Improvements	**Acquisition Range**		**Winter Peak Reduction (MW)**	**Energy (aMW)**
Energy Efficiency	2016-2035		193	132
Distribution Efficiencies			<1	<1
Total Efficiency			193	132

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

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

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

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

For the short-term timeframe, the Company's Energy Resources Risk Policy guides its approach to hedging financially open forward positions. A financially open forward period position may be the result of either a short position situation, for which the Company has not yet purchased the fixed-price fuel to generate, or alternatively has not purchased fixed-price electric power from the market, to meet estimated average load for the forward period. Or it may be a long position, for which the Company has generation above its expected average load needs, and has not yet made a fixed-price sale of that surplus to the market in order to balance resources and loads.

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

III. GENERATION CAPITAL PROJECTS

Q. Please explain how the Company prepared its case with regards to generation capital projects.

A. The Company started with the historical test period ending December 31, 2015 and included pro forma adjustments for planned capital investment in 2016 and 2017. For further discussion regarding the Pro Forma adjustments and the Capital Planning Group, please see Company witness Ms. Schuh's testimony.

Q. Please describe the capital planning process that the Generation area goes through before generation capital projects are submitted to the Capital Planning Group.

A. Currently, the Generation Production Substation Support (GPSS) capital projects are proposed by the Generation Engineering group or by the Plant Operations groups. These projects are then included into the long range (10 year) plan and prioritized by the Chief Generation engineer with input from GPSS leadership including the Department Director, Plant and Central Maintenance Managers, and Avista's Asset Management group. A Basis of Design document is then created for these projects and a Business Case developed. As these projects come into the 5-year planning horizon, more detail on Scope, Schedule, and Budget are added to the plan. If the project is still judged viable and prudent by GPSS leadership it is sent to the Capital Planning Group for funding. After a project is approved, and during the life of a project, steering committees are established for executive management check-ins and approvals of decisions as they arise throughout the project.

The Company has also historically performed specific assessments on groups of assets. For example, in 2011 the Company performed The Spokane River Assessment (SRA) to assess the hydro capacity upgrade potential for all of the Spokane

River Project hydroelectric plants. The SRA was guided by a Policy Team consisting of the Vice President of Energy Resources and the department directors and managers from Power Supply, Resource Planning, GPSS, Environmental Affairs, Substation, Relay and Protection, Transmission Planning, and Finance. Task groups were also formed to provide detailed oversight of specific portions of the assessment, such as Finance, Environmental, and Engineering. The final recommendation of the SRA in 2012 was to rehabilitate the existing plant instead of building a new powerhouse at Nine Mile. This recommendation led to the formation of the Nine Mile Rehab Program (NMRP) Business Case to address the rehabilitation of the powerhouse and associated facilities. The NMRP Business Case is governed by steering committees consisting of director level management teams providing input and authorization for changes to scope, schedule, and cost. The steering committees provide a level of governance and oversight to support the NMRP Business Case and, when necessary, provide recommendations to the Capital Planning Group (CPG) for adjustments in the NMRP program level cost and annual budget.

Q. What is driving the capital needs in the Company's generation area?

A. The main drivers for the generation-related capital investment include updating and replacing equipment in many of the Company's hydro facilities that are over 100-years old in order to reduce equipment-failure forced outages. In addition, regular maintenance for reliability is required to keep the generating plants operational. Furthermore, there are projects to address plant safety and electrical capacity issues. Finally, there are capital requirements resulting from our settlement agreements for the implementation of Protection, Mitigation and Enhancement (PM&E) programs related to the FERC Licenses for the Spokane River and Clark Fork River.

Q. Would you please provide a brief description of the generation-related capital projects that are included in the Company's Pro Forma Study for 2016 through 2017?

A. Yes. As shown in Table No. 6 below, for 2016 and 2017 the Company has included generation projects totaling, on a system basis, \$165.4 million and \$75.8 million, respectively. Details about these generation-related capital projects are discussed below.

TABLE NO. 6

Generation / Production Capital Projects (System)

Business Case Name	**2016 $ (000's)**	**2017 $ (000's)**
Colstrip Thermal Capital	$ 12,292	$ 12,432
Cabinet Gorge Unit 1 Refurbishment	14,702	
Post Falls South Channel Replacement	15,648	
Nine Mile Rehab	73,193	3,814
Little Falls Plant Upgrade	23,833	11,470
Spokane River License Implementation	$ 1,007	$ 17,764
Kettle Falls Stator Rewind		7,930
Peaking Generation	500	500
Cabinet Gorge Automation Replacement		2,342
Cabinet Gorge HED - Gantry Crane Replacement		3,500
Kettle Falls CT Control Upgrade		667
Kettle Falls Reverse Osmosis System	4,750	
Generation DC Supplied System Upgrade	700	1,033
Coyote Springs Long Term Service Agreement	1,980	1,980
Noxon Station Service	1,477	1,172
Base Load Hydro	1,149	1,149
Regulating Hydro	5,786	3,533
Base Load Thermal Plant	2,200	2,200
Clark Fork Settlement Agreement	6,093	4,226
Hydro Safety Minor Blanket	75	80
Total Planned Generation/Production Capital Projects	**$ 165,387**	**$ 75,791**

The following planned generation capital projects are included in the Company's Pro Forma Study. See Ms. Schuh's Exhibit No. 10, Schedule 4 for business cases supporting these projects.

Colstrip Capital Additions - 2016: $12,292,000; 2017: $12,432,000

This program includes ongoing capital expenditures associated with normal outage activities on Units 3 & 4 at Colstrip. Every two out of three years, there are planned outages at Colstrip with higher capital program activities. For non-outage years, the program activities are reduced. Planned capital investments include the overhaul of Unit 4, NOx emission reduction equipment, and replacement of gas deflection nose arches for Units 3 & 4, among other investments. Avista votes its 15% share of Units 3 & 4 and its approximate 10% share of common facilities to approve or disapprove of the planned expenditures proposed by Talen Energy on behalf of all the owners.

Cabinet Gorge Unit 1 Refurbishment – 2016: $14,702,000

This is the capital portion of a major overhaul project associated with Cabinet Gorge Unit #1. Unit No. 1 at Cabinet Gorge is designed with variable pitch blades, which provide for flexible operation with variable water flows (e.g., minimum flows through the project), the remaining three units at Cabinet Gorge are fixed-blade units. The runner hub had significant mechanical issues and needed to be replaced to support minimum flow for fish habitat and allow for frequent cycling associated with the integration of intermittent renewable resources. The present automatic voltage regulator (AVR) provides a relatively slow response due to its hybrid design and has no limiters for generator protection. A new AVR system will provide faster response and add limiters. New machine monitoring will provide better analysis of machine condition for this important unit that supports minimum flow operation.

The initial completion date for this project was May of 2015. This project is now estimated to be on-line in May of 2016. The Company encountered several issues during construction of Unit #1 causing this delay, such as issues with the supply schedule from the manufacturer and construction quality issues with the turbine resulting in delivery delays and additional site work, and an unforeseen governor upgrade required to ensure reliable operation of the new turbine.

Post Falls South Channel Replacement - 2016: $15,648,000

This project involved the maintenance of the south channel gates to comply with FERC Dam Safety directives. The South Channel Dam was originally constructed in 1906. A pre-construction underwater investigation revealed that the condition of the concrete structure was very poor and would not handle the planned work. This resulted in an evaluation of different design options to address the deteriorated concrete. The final project removed most of the existing concrete structure and replaced it with new concrete, new spillway gates, and new hoist systems to automate gate operation.

The initial estimated completion date for this project was May of 2015. This was based on our observation of the dam condition, dive inspections, and estimates of the concrete suitability for rehabilitation. Once construction started, the Company encountered several unforeseen issues directly related to working in areas that are normally submerged and part of a 100 year old structure. For example, during installation of the coffer dam, the north bank was found to have a severe undercut that required significant efforts to secure before any reconstruction work could begin. Once removal of the existing concrete began, the poor condition of the concrete required further extraction to provide an adequate foundation for the new concrete. This significantly impacted the scope of project, requiring additional design, permits, and construction work. These delays resulted in concrete work being performed later in the year, further slowing construction as winter pouring is a slower process. This project went into service in February of 2016.

Nine Mile Redevelopment – 2016: $73,193,360; 2017: 3,814,000
This capital program is necessary to rehabilitate and modernize the four unit Nine Mile HED. The program includes projects to replace the existing three MW Units 1 and 2, which are more than 100 years old and worn out, with two new eight MW generators/turbines. The new units will add 1.4 aMW of energy beyond the original configuration. In addition to these capacity upgrades, the Nine Mile facility has and will receive upgrades to the following during the years listed:

- hydraulic governors (Units 1-2 in 2016 and Units 3-4 in 2019);
- static excitation system (Units 1-2 in 2016 and Units 3-4 in 2019);
- switchgear (Units 1-2 in 2016 and Units 3-4 in 2019);
- station service (interim station service completed in 2013 and permanent replacement in 2016);
- control and protection packages (Units 1-2 in 2016 and Units 3-4 in 2019);
- ventilation upgrades (2016);
- rehabilitation of intake gates (Units 1-2 completed in 2015; Units 3-4 in 2017) and sediment bypass system (2016-2018);
- a new warehouse completed in 2015;
- new tail race gate system completed in 2015;
- new grounding and communications completed in 2013 and 2015 respectively;
- a barge landing and crane pad completed in 2015;

- a cottage removed in 2013 and another remodeled in 2015;
- a new panel room completed in 2013;
- Units 3 and 4 will be overhauled and modernized (2018-2019);
- the powerhouse will be restored (2017);
- new access gates and controls added in 2015; and
- other improvements will be made throughout the rehabilitation and modernization of the project.

The Nine Mile rehabilitation project, specifically Units 1 and 2, have incurred some delays from the original estimated completion date of December 2015. Limited structural support for the tailrace gates significantly impacted plant dewatering. Nine additional months were required to design and fabricate additional support. This delay impacted the timing for powerhouse demolition, concrete placement, and placement of new equipment. Electrical completion also took nine additional months for design, fabrication and installation based on the need for specialized support structures for the new electric cable tray system. The completion date for this project is now expected in July of 2016.

Little Falls Powerhouse Redevelopment – 2016: $23,833,000; 2017: $11,470,000

The Little Falls equipment ranges in age from 60 to more than 100 years old. Forced outages at Little Falls because of equipment failures have significantly increased from about 20 hours in 2004 to several hundred hours in the past few years. This project replaces nearly all of the older, unreliable equipment with new equipment, including replacing two of the turbines, all four generators, all generator breakers, three of the four governors, all of the automatic voltage regulators, removing all four generator exciters, replacing unit controls, changing the switchyard configuration, replacing unit protection system, and replacing and modernizing the station service. Without this focused replacement effort, forced outages and emergency repairs would have continued to increase, reducing the reliability of the plant. At some point, personnel would have been placed back in the plant adding to operating costs. The Asset Management group analyzed the age and condition of all of the equipment in the plant, all of the equipment was qualified as obsolete in accordance with the obsolescence criteria tool. There are many items in this 100 year old facility which do not meet modern design standards.

This replacement effort will allow Little Falls to be operated reliably and efficiently.

The Little Falls Unit 3 project encountered some delays from the initial estimated completion date of April of 2015. The Company encountered several issues during construction of this project. The turbine runner was supplied out of specification and was returned to the manufacturer. The manufacturer supplied another turbine after six additional months of manufacturing. The project recouped some costs by exercising liquidated damages but could not recoup the delay in the delivery schedule. This major delay, along with various smaller delays, caused the project completion to be delayed until late December 2015. This project was not placed in service until February of 2016 due to Avista generation crews helping with the Windstorm and delays during checkout of the new control system.

Spokane River Implementation PM&E – 2016: $1,007,000; 2017: $17,764,000

This capital spending category covers the implementation of Protection, Mitigation and Enhancement (PM&E) programs related to the FERC License for the Spokane River including Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake. This includes items enforceable by FERC, mandatory conditioning agencies, and through settlement agreements. Additional details concerning the PM&E measures for the Spokane River license are included in the hydro relicensing section later in this testimony. This License defines how Avista shall operate the Spokane River Project and includes several hundred requirements that we must meet to retain this License. Overall, the License is issued pursuant to the Federal Power Act. It embodies requirements of a wide range of other laws, including the Clean Water Act, the Endangered Species Act, and the National Historic Preservation Act, among others. These requirements are also expressed through specific license articles (or Protection, Mitigation and Enhancement Measures), relating to fish, terrestrial resources, water quality, recreation, education, cultural, and aesthetic resources at the Project. In addition, the License incorporates requirements specific to a 50-year settlement agreement between Avista, the Department of Interior and the Coeur d'Alene Tribe, which includes specific funding requirements over the term of the License. Avista entered into additional two-party settlement agreements with local and state agencies, and the Spokane Tribe; these agreements also include funding commitments. The License references our requirements for land management, dam safety, public safety and monitoring requirements, which apply for the term of the License.

Kettle Falls Stator Rewind – 2017: $7,930,000

The Kettle Falls generator is 32 years old and is at the end of its expected life. The stator can be rewound on its scheduled basis during the spring outage of 2017 instead of running it until it fails. This project consists of monitoring the existing machine, developing rewind contract, manufacturing replacement coils, disassembly, coil removal, new coil installation, reassembly, startup, testing and commissioning. The consequences of a stator failure include an unscheduled outage with lost generation, loss of renewable energy credits, long term interruption of fuel supply, potential collateral damage to the core and hydrogen cooling, and poses a significant safety hazard.

Peaking Generation – 2016: $500,000; 2017: $500,000

This program is focused on the capital maintenance expenditures required to keep the natural gas-fired peaking units (Boulder Park, Rathdrum CT, and Northeast CT) operating at or above their current performance levels. The program focuses on maximizing the ability of these units to start and run efficiently when requested (starting reliability). The reliability of all of these assets will decline over time, resulting in failure to start, non-compliant emissions, or inefficient operation. It is critical that these facilities start when requested to reduce exposure to high market prices or the loss of other Company resources. The program includes initiatives to meet FERC, NERC and EPA mandated compliance requirements.

Cabinet Gorge Hydroelectric Dam Automation Replacement – 2017: $2,342,000

This project replaces the unit and station service control equipment with a system compatible with Avista’s current standards. The technology currently used at Cabinet Gorge is an older vintage and is marginally supported. The existing control system is obsolete and there are a very limited number of spares, so some replacement parts for the system can only be found through the secondary and salvage markets. In addition, the current system does not provide enough inputs and outputs to implement the standard unit control and monitoring schemes. Therefore unit monitoring and control is inconsistent with current industry practice. The scope of work also includes replacement of the governors, voltage regulators, and protective relays.

Replace Cabinet Gorge Gantry Crane – 2017: $3,500,000
The gantry crane at Cabinet Gorge is original equipment and is now more than 60 years old. This is a critical asset needed to service the powerhouse. The crane has experienced problems which impacted the Cabinet Gorge Unit 1 project schedule. The controls are antiquated and have malfunctioned. The cranes operating integrity, and the state of the controls, make replacing the crane with a modern and fully functioning crane a necessity.

Kettle Falls CT Control Upgrade – 2017: $666,607
This project will replace the Solar Combustion Turbine HMI software and hardware, upgrade PLC controls platform, and Fire Protection system at Avista's Kettle Falls Generating Station. The current controls are outdated, with spare parts and software support no longer available. Failure to fund this project will result in the system continuing to deteriorate, increasing the risk of forced outages.

Kettle Falls Generating Station Reverse Osmosis System – 2016: $4,750,000
The Kettle Falls Generating Station needs a long term solution to achieve environmental permit compliance, improve the well water supply chemistry, and replace an aging demineralization system. Currently, several short term solutions have been employed with increasing and unsustainable operation costs, which includes the use of chemicals at a cost of $40,000 per month and risk associated with a deionization system. This project will design and install a new water treatment system at Kettle Falls. If this project is not completed, it could result in plant discharge permit violations and potential third party intervention.

Generation DC Supplied System Upgrade – 2016: $700,000; 2017: $1,033,000
This project will update existing plant DC systems to meet Avista's current Generation Plant DC System Standard. This program will make compliance with NERC PRC-005 Reliability Standard more tenable and significantly reduce plant outage times now required for periodic testing to meet the standard. The project changes DC System configurations to more easily comply with the NERC requirements for inspection and testing. It addresses battery room environmental conditions to optimize battery life. The project will replace any legacy Uninterrupted Power Supply (UPS) systems with an inverter system and address auxiliary equipment based on its life cycle. The Company is

currently addressing Battery Bank replacement based on the manufacturers recommended life cycle. This life cycle is based on ideal operating conditions. Replacing components as they fail adds significant risk of unpredictable full system failures leading to forced plant outages.

Coyote Springs 2 LTSA Capital Addition – 2016: $1,980,000; 2017: $1,980,000

This program covers the capital accruals required to execute our Long Term Service Agreement (LTSA) with General Electric for Coyote Springs Unit 2. The LTSA contract is with General Electric to maintain the gas turbine at Coyote Springs 2 and provide scheduled part exchanges based on unit run hours. This program will have fluctuations to account for the variable operating hours and operating conditions that feed into the LTSA formula. This contract with GE provides the necessary services, parts, and labor to maintain the Frame 7EA gas turbine, which is the major component of the Coyote Springs Unit 2 CCCT.

Noxon Station Service – 2016: $1,477,000; 2017: $1,172,000

An engineering study has shown that the station service equipment at Noxon is over-rated and may not interrupt a close in fault should one occur. In addition, as the plant load has shifted, the simultaneous operation of all five units may be limited if one of the station service transformers fails. This project replaces station service equipment and cables. The replacements include Station Service transformers A&B, 2000A Bus Ducts from Station Service transformers to Power Centers, Tie Bus and Power Centers, Motor Control Centers 1 through 4, 1,000 kVA Emergency Generator, Motor Control Center 4 PLC, and the Emergency Load Center. If no action is taken, there is a risk of catastrophic switch gear failure and generator unit forced outage for up to a year. Additionally, forced generation limits under certain operational scenarios could be necessary if these replacements are not made.

Base Load Hydro – 2016: $1,149,000; 2017: $1,149,000

This program covers the capital maintenance expenditures required to keep the Upper Spokane River Plants: Post Falls, Upper Falls, Monroe Street, and Nine Mile, operating within 90 percent of their current performance (this assumes some degradation of performance over time.) The program will focus on ways to maintain compliance and reduce overall O&M expenses while maintaining a reasonable unit availability. This program also includes FERC and NERC mandated compliance requirements.

These compliance projects are managed as part of the overall Base Load Hydro program and are not separated out as individual items. The historical availability for the base load hydro plants has been declining over the past ten years due to deteriorating equipment and a need to replace aging equipment and systems. The age of these plants range from 90 to 105 years old.

Regulating Hydro – 2016: $5,786,000; 2017: $3,533,000

This program covers the capital maintenance expenditures required to keep the Long Lake, Little Falls, Noxon Rapids and Cabinet Gorge plants operating at their current performance levels. The program works to improve plant operating reliability so unit output can be optimized to serve load obligations or sold to bilateral counterparties. Work is prioritized according to equipment needs. Sustaining this asset management program is very important as these facilities age and are ramped more frequently to meet load fluctuations associated with renewable energy integration and changing load dynamics. Additionally, efforts will be made within this program to improve ancillary service capabilities from these generating assets. This includes installing blow down systems to allow for spinning reserves, moving load following demands to all of these plants, voltage regulating needs, and frequency response. The program also includes some elements of hydro license compliance related to plant operations and equipment.

Base Load Thermal Plant – 2016: $2,200,000; 2017: $2,200,000

This program is necessary to sustain or improve the operation of base load thermal generating plants, including Coyote Springs 2, Colstrip, Kettle Falls, and Lancaster. Capital projects include replacement of items identified through asset management decisions and programs necessary to maintain reliable operations of these plants. As this asset maintenance program matures, it is expected that forced outage rates and forced de-ratings of these facilities will decrease to a level one standard deviation less than the current average. As these plants continue to age and they are called upon to ramp more frequently to meet variations associated with renewable energy integration, their operating performance begins to degrade over time resulting in increased forced outage rates and exposure to the acquisition of replacement energy and capacity from the market. Having a mature asset management program for these thermal facilities will help minimize plant degradation and market exposure. The program also includes initiatives associated with regulatory mandates for air emissions and monitoring, and projects to meet NERC compliance requirements.

Clark Fork Settlement Agreement – 2016: $6,093,000; 2017: $4,226,000

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

Hydro Safety Minor Blanket – 2016: $75,000; 2017: $80,000

This item funds periodic capital purchases and projects to ensure public safety at hydro facilities, on and off water, in the context of FERC regulatory and license requirements. Section 10(c) of the Federal Power Act authorizes the FERC to establish regulations requiring owners of hydro projects under its jurisdiction to operate and properly maintain such projects for the protection of life, health and property. Title 18, Part 12, Section 42 of the Code of Federal Regulations states that, "To the satisfaction of, and within a time specified by the Regional Engineer an applicant, or licensee must install, operate and maintain any signs, lights, sirens, barriers or other safety devices that may reasonably be necessary. Hydro Public Safety measures includes projects as described in the FERC publication "Guidelines for Public Safety at Hydropower Projects" and as documented in Avista's Hydro Public Safety Plans for each of its hydro facilities.

IV. HYDRO RELICENSING

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

A. Yes. Avista received a new 45-year FERC operating license for its Cabinet Gorge and Noxon Rapids hydroelectric generating facilities on the Clark Fork River on March 1, 2001. The Company has continued to work with the 27 Clark Fork Settlement Agreement signatories to meet the goals, terms, and conditions of the Protection, Mitigation and Enhancement (PM&E) measures under the license. The implementation program, in coordination with the Management Committee which oversees the collaborative effort, has resulted in the protection of approximately 89,000 acres of bull trout, wetlands, uplands, and riparian habitat. More than 41 individual stream habitat restoration projects have occurred on 24 different tributaries within our project area. Avista has collected data on over 25,000 individual Bull Trout within the project area.

The upstream fish passage program, using electrofishing, trapping and hook-and-line capture efforts, has reestablished Bull Trout connectivity between Lake Pend Oreille and the Clark Fork River tributaries upstream of Cabinet Gorge and Noxon Rapids Dams through the upstream transport of 538 adult Bull

Trout, with over 160 of these radio tagged and their movements studied. Avista has worked with the U.S. Fish and Wildlife Service to develop and test two experimental fish passage facilities. Avista, in consultation with key state and federal agencies, is currently developing designs for a permanent upstream adult fishway for Cabinet Gorge and discussing the timing of, and need for, a fishway at Noxon Rapids.

In 2015, the Cabinet Gorge Fishway Fish Handling and Holding Facility was completed. A permanent tributary trap on Graves Creek (an important bull trout spawning tributary) was constructed in 2012 and testing began 2013. The permanent trap is being iteratively optimized and evaluated to determine if additional permanent tributary traps are warranted. Concurrently, the physical attributes at a site on the East Fork Bull River are being evaluated to determine if this would be a feasible location for a future permanent trap.

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

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

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

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

The 2006 Preliminary Design Development Report for the Cabinet Gorge Bypass Tunnels Project indicated that the preferred tunnel configuration did not meet the performance, cost and schedule criteria established in the approved Gas Supersaturation Control Plan (GSCP). This led the Gas

Supersaturation Subcommittee to determine that the Cabinet Gorge Bypass Tunnels Project was not a viable alternative to meet the GSCP. The subcommittee then developed an addendum to the original GSCP to evaluate alternative approaches to the Tunnel Project.

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

FERC approved the GSCP addendum in February 2010, and in April 2010 the Gas Supersaturation Subcommittee (a subcommittee of the MC) chose five TDG abatement alternatives for feasibility studies. Feasibility studies and preliminary design were completed on two of the alternatives in 2012. Final design, construction, and testing of the spillway crest modification prototype was completed in 2013. Test results indicated over all TDG performance was positive, however, additional modifications were required to address cavitation issues. Modification of the spillway crest prototype and retesting were completed in 2014. Based on this design, construction of two additional spillway crest modifications were completed in 2016.

It is anticipated that up to five additional spillway crests will be modified by 2018.

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

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

Since 2011, Avista has implemented wetland, water quality, fisheries, cultural, recreation, erosion, aquatic weed management, aesthetic, operational and related conditions across all five hydro developments under the Protection Mitigation and Enhancement (PM&E) measures. Six hundred and fifty six acres of wetland mitigation properties were acquired in 2011 and 2012 along Upper Hangman Creek in Idaho for the Coeur d'Alene Tribe (Tribe) through the Coeur d'Alene Reservation Trust Resources Restoration Fund that Avista established in 2009. The Company has since developed and implemented wetland restoration plans for 508 of the required 1,424 replacement acres of wetland and riparian habitat along Upper Hangman Creek in cooperation with the Tribe. Avista and the Tribe continue implementing the plans by assessing and pursuing additional lands, primarily on the Coeur d'Alene Reservation, for acquisition and wetland and riparian habitat restoration.

The Company implemented its management plan for the 109 acre Sacheen Springs Wetland Complex located along the Little Spokane River and will monitor its restoration efforts, as required for the term of the license.

Avista will continue to develop and implement local, state, and federally required work plans related to fisheries and water quality to fulfill License conditions.

One on-going study includes assessing redband trout spawning areas in the Spokane River downstream of the Monroe Street Dam, (over a 10-year period) to determine if spring water releases from the Company's Post Falls Dam should be changed to benefit the spawning areas. Another such study included one specific to total dissolved gas (TDG) downstream of Long Lake Dam. Avista modeled several different types of spillway modifications between 2011 and 2013 and completed the design for the desired deflector configurations in 2014. The Company is planning to complete the spillway modification project in 2016-2017. Cost estimates to construct the TDG spillway deflectors are approximately $11.0 million.

The Company completed the proposed dissolved oxygen (DO) measure in the tailrace below Long Lake Dam and continues to monitor its effectiveness in addressing low DO in the river below the dam. The monitoring efforts will be ongoing in nature, as the Company has to balance improved DO conditions with increases in TDG, which can be detrimental to downstream fish. Avista is also continuing to evaluate potential measures to improve DO in Lake Spokane, the reservoir created by the Long Lake Dam. Cost estimates to address DO in Lake Spokane are between $2.5 and $8.0 million. These estimates will be refined as the evaluations and studies are completed.

To meet the Company's water quality monitoring requirements under the license, it partnered with the Idaho Department of Environmental Quality to complete nutrient monitoring in the northern portion of Coeur d'Alene Lake and in the Spokane River downstream of the Lake's natural outlet. It also partnered with the Tribe to complete nutrient monitoring in the southern portion of Coeur d'Alene Lake and the lower St. Joe River. The Company also conducted nutrient monitoring in Lake Spokane as part of its Lake Spokane Dissolved Oxygen Water Quality Attainment Plan.

Avista and the Tribe continue to implement the Cultural Resource Management Plan on the Reservation, whereas Avista implements Historic Property Management Plans (off the Reservation) on Project lands in both Idaho and Washington. The primary measures include site monitoring, looting patrol, education and outreach, curation of materials collected, and reporting.

The Company continues to work with the various local, state, and federal agencies to manage the required recreation projects in Idaho and Washington. Last year, the Company completed the Trailer Park Wave River Access in Idaho, and ten boat-in-only campsites and a carry-in-only boat launch in Washington.

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

A. Yes it does.