Exh. JRT-1T

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BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-19____________

DIRECT TESTIMONY OF

JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Jason R. Thackston. I am employed as the Senior Vice President of Energy Resources 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 Whitworth University in 1992 with a Bachelor of Arts in International Studies and an emphasis in Business Management and a Master of Business Administration from Gonzaga University in 2000. I joined the Company in 1996 as a Corporate Treasury Analyst. I have held several different positions at Avista, including roles in Finance and Accounting, Internal Audit, Risk Management, Power Supply, and Gas Supply. I was appointed Vice President of Finance in June 2009 and have since held the roles of Vice President of Energy Delivery and Vice President of Customer Solutions before assuming my current role in January 2013. The Energy Resources group is primarily responsible for producing or procuring the electricity and natural gas to serve our customers' needs, including the construction, operation, and maintenance of our generation facilities and the optimization of those electric and natural gas facilities for the benefit of our customers.

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

A. My testimony provides an overview of the Company's recently announced 100% Clean Electricity goal by 2045, and carbon neutral electricity supply of the end of 2027, and why it is important to our Company. I will also provide an overview resource planning and power supply operations. This includes summaries of the Company's current and future resource plans, as well as an overview of the Company's Energy Resources Risk Policy, and an update on Avista's participation in the California Independent System Operator Corporation ("CAISO") Western Energy Imbalance Market. I will address the major generation-related capital projects included in this case as well as Colstrip Unit Nos. 3 and 4 capital projects for the periods 2017-2019.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exh. JRT-2 is Avista's 2017 Electric Integrated Resource Plan and Appendices. Confidential Exh. JRT-3C is Avista's Energy Resources Risk Policy. Exh. JRT-4 includes a listing of all the generation capital projects that have transferred to plant during 2017-2018. Exh. JRT-5 includes the capital business cases for the major projects in 2017 and 2018, as well as the 2019 pro forma projects, all of which are discussed later in my testimony.

II. 100% CLEAN ELECTRICITY BY 2045 GOAL

Q. The Company recently announced a 100% clean electricity goal by 2045, and carbon neutral electricity supply by the end of 2027. Why is this important to the Company?

A. The announcement made in April 2019 bolsters Avista's long-standing history of, and well-established approach to, providing clean, reliable and affordable energy to the customers and communities we serve. We believe that the 100 percent clean electricity goal is an important step forward in caring for our environment while continuing to meet the energy needs of our customers and communities today and well into the future. Since Avista's founding on clean, renewable hydro power in 1889, we've served our customers with an electric generation resource mix that is more than half renewable, allowing us to keep our carbon emissions among the lowest in the nation. Further, the Company has always been committed to balancing reliability and affordability while maintaining responsibility for our environmental footprint, and our actions demonstrate these values. Just in the last three years, we've implemented three renewable energy projects on behalf of our customers. Our Community Solar project in Spokane Valley, Solar Select project in Lind, and the Rattlesnake Flat Wind project in Adams County together have allowed us to add to the clean electricity we already provide, meet the energy needs of our customers without increasing their bills and drive economic vitality in these communities.

Q. Can you provide other examples of environmental stewardship?

A. Yes. Additional examples of Avista's record of environmental stewardship include:

- Forty years ago, Avista was one of the first utilities in the nation to establish an energy efficiency program, and since this program started, customer electric usage has been reduced by 15 percent.

- In the 1980's, the Company built the first utility-scale biomass wood-fired power plant, improving air quality where waste from the timber industry was otherwise burned onsite without emissions controls.

- Avista has enabled customers to switch from gasoline-fueled vehicles to natural gas-fueled and electric vehicles, building infrastructure to supply a cleaner fuel for vehicles and contributing to reductions in greenhouse gas emissions from the transportation sector.

Q. Why is Avista declaring an electric carbon neutral goal now?

A. We have seen a growing focus on clean electricity generation at the national, regional, and local levels. Our customers and communities are increasingly expressing an interest in knowing how Avista is positioned on this topic. While we have a strong and long track record related to clean electric generation, we felt it was time to be clear about our path forward. Reaching this goal, of course, will require further improvements in costs and technology associated with clean electric generation and energy storage, as well as regulatory support. Going forward, we will track progress through our Integrated Resource Plan, which is filed every two years.

Q. What does carbon neutral mean and what percent of Avista's load is actually served with renewables?

A. Carbon neutral means achieving an overall net-carbon footprint by meeting our customers' annual electric needs through either utilizing non-carbon emitting resources, or investing in or acquiring carbon offsets to net-out emissions created from carbon emitting resources. An example of a carbon offset is acquiring renewable energy credits from a renewable energy resource. Currently, over 60 percent of Avista's customers' annual electric need is served from clean non-carbon emitting resources.

Q. Does this mean Avista is getting out of Colstrip?

A. Colstrip has been an important source of generation in the region and for Avista's customers for over 30 years. It is available to serve our customers when the wind isn't blowing, the sun isn't shining, or there isn't enough water flowing down our rivers to generate enough electricity to meet our customers' energy needs. As the costs and technology of clean energy and energy storage continue to improve, and as other markets develop, we anticipate there will be a time when we no longer need Colstrip, and we continue to work with our five co-owners related to the future of the plant.

Q. How does natural gas fit with the Company's clean energy goal?

A. Natural gas has been a key energy choice for Avista's customers for nearly 70 years. It is an affordable and less expensive heating option for customers, especially for many large commercial and industrial customers who rely on it to run their business, provide jobs for their employees and serve their communities. Natural gas is one of the cleanest burning fuels and is an essential part of reducing carbon emissions, particularly when used directly by customers in their homes rather than used to generate electricity to meet the same need. Compared to wood, heating oil and other fuels, natural gas improves air quality. Additionally, the use of compressed natural gas (CNG) to fuel vehicles reduces carbon emissions in the transportation sector, which is a leading contributor of emissions. Avista consistently engages customers to educate about natural gas efficiency, and offers natural gas energy efficiency programs that also support lower emissions. In short, direct use of natural gas is efficient, creates less environmental impact than other fuels and is an affordable option for customers.

Q. How does energy efficiency play a role in this plan?

A. Energy efficiency has been an important piece of our energy resource puzzle for 40 years, and we will continue to partner with our customers to use electricity more efficiently. Energy efficiency is good for the customers' energy use, and it reduces our need to build additional generation, reducing the carbon intensity of our local economy.

III. RESOURCE PLANNING, POWER OPERATIONS, AND ENERGY IMBALANCE MARKET

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 (Power Supply) is responsible for dispatch decisions related to those resources for which the Company has dispatch rights. Power Supply 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), demand response, energy storage, 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 2017 IRP shows forecasted annual energy and capacity deficits beginning in 2027. The capacity and energy load/resource positions are shown on page 6-7 and page 6-9 of Exh. JRT-2.

The next Electric IRP is currently being developed and is scheduled to be filed with the Commission on February 28, 2020, after the Commission issued Order 01 in Docket UE-180738 where it approved a delayed filing from the original August 31, 2019 filing date. The extension to file the IRP in 2020 allows extra time to model legislation in Washington State which will fundamentally change the Company’s resource planning targets. In particular, "Clean Energy" legislation (House Bill 1211 and Senate Bill 5116) proposes to eliminate all coal-fired resources from serving Washington load by the end of 2025, requires all Washington load to be served with 100 percent carbon neutral resources by 2030, and prohibits the use of fossil-fuel generation for Washington load by 2045. The Company will work with the Commission to ensure these new requirements concerning coal-fired and other carbon emitting resources will be modeled appropriately and met in the Preferred Resource Strategy.

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

A. Until supported by the next Electric IRP (to be filed February 2020), the Preferred Resource Strategy (PRS) in the current Electric IRP guides the Company's resource acquisitions, subject to any legislative requirements. 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 2017 Electric IRP in Docket No. UE-161036 on May 7, 2018. The IRP represents the preferred plan at a point in time; however, Avista continuously evaluates different resource options to meet current and future load obligations, especially in light of new legislation.

Avista's 2017 PRS includes 203 MWs of cumulative energy efficiency, 44 MWs of demand response, 5 MWs of energy storage, 34 MWs of upgrades to existing thermal plants, and 335 MWs of natural gas-fired peaking plants. The timing and type of these determined resources in the 2017 IRP is provided in Table No. 1.

Table No. 1: 2017 Electric IRP Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Winter Peak (MW)	Energy (aMW)
Solar	2018	15	0.00	3
Natural Gas Peaker	2026	192	203.7	178
Thermal Upgrades	2026-2029	34	34.0	31
Storage	2029	5	5.0	0
Natural Gas Peaker	2030	96	101.9	89
Natural Gas Peaker	2034	47	46.5	43
Total		**389**	**392**	**344**
Efficiency Improvements	**Acquisition Range**		**Winter Peak Reduction**	**Energy (aMW)**
Energy Efficiency	2018-2037		203	108
Demand Response	2025-2037		44	0
Distribution Efficiencies			<1	<1
Total[1]			**247**	**108**

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 customers and managing Company-owned and controlled resources. The Energy Resources Risk Policy, which is attached as Confidential Exh. JRT-3C, 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).

[1] Does not include recent Solar and Wind acquisitions discussed below.

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 as fuel for electric generation. The policy considers several factors, including the variability associated with loads, hydroelectric generation, planned and forced 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 current Integrated Resource Plan's Preferred Resource Strategy, 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 and availability, 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 projected average load for the forward period. Or it may be a long position, for which Avista 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 financial position against expected load as forward periods draw nearer.

Q. Would you please provide an update concerning Avista's involvement with the Western Energy Imbalance Market?

A. Avista has been actively monitoring the operation and development of the CAISO Western Energy Imbalance Market (EIM). The Company regularly participates in regional meetings and dialogue associated with the EIM including the potential expansion of the EIM to incorporate day ahead transactions. Avista is continuously evaluating the operational benefits associated with EIM participation, and the associated risks of not participating in the market. One of the largest operational benefits for current EIM participants is the ability to balance and regulate renewable resources by leveraging available market resources instead of relying on only internal Avista resources to provide regulation and flexible ramping for variable resources.

Avista's renewable resource mix is changing as the price of renewable resources continue to decline and our customer's increased interest in purchasing cleaner energy. Recently, Avista signed two Power Purchase Agreements (PPA) for 20 MW of solar starting in December of 2018 (Adams-Neilson) and 144 MW of wind starting in late 2020 (Rattlesnake Flats), based on customer demand and competitive pricing. Avista expects to integrate additional renewable resources into its Balancing Authority Area (BAA) in the future associated with the development and adoption of national, state and local clean energy or carbon emission policies, and the increased interest of qualifying resources that meet the requirements under the Public Utility Regulatory Policies Act. As additional variable resources are integrated into the Avista BAA, it becomes more efficient and cost-effective for Avista to rely on the EIM to help meet the in-hour variability of renewable resources, instead of holding back and dispatching Avista owned resources to meet the flexible ramping requirements.

Avista has also closely monitoring the impacts to the bi-lateral trading market as more entities join the EIM. The recent integration of Idaho Power and Powerex into the EIM had an impact on market liquidity in the summer of 2018. In addition, the commitment of Seattle City Light and NorthWestern Energy and the notice of intent of the Bonneville Power Administration to join the market in the next few years, will continue to put a stress on near term market liquidity. EIM participants are less likely to conduct bi-lateral transactions close to the operating hour, due to the need to pass EIM sufficiency and flexible ramping tests and meet other market transaction closing times that occur well before the operating hour. This leads to significant risk and inefficiencies for non-market participants to reliably and responsibly meet load service obligations.

Based on Avista's changing resource portfolio, that will include additional variable resources in the near future, and the risks of being one of the few non-EIM participants, Avista has decided to join the Western EIM. Avista signed an EIM implementation agreement with the CAISO on April 25, 2019 with a planned go-live date of April 1, 2022. Avista is currently working with the CAISO to develop a project plan to meet the different implementation milestones to ensure Avista is prepared to enter the market on schedule.

Q. What is the estimated cost and benefit associated with Avista joining the EIM?

A. Avista recently updated and re-evaluated our previous cost and benefit assessments associated with participating in the EIM. Utilicast was hired in the second half of 2018 to help Avista develop a technology road map and perform a metering assessment associated with EIM participation. Utilicast also updated the market costs assessment that it had previously conducted for the Company in 2015. Avista estimates it will cost between $21 and $26 million to fully prepare for market entry. These costs include metering, generation controls, and communication infrastructure additions and improvements, the purchase and integration of at least six market based software applications, the hiring of a System Integrator consultant, and internal Avista labor. The on-going annual costs to operate in the market are anticipated to be between $3.5 and $4.0 million. These amounts include maintenance costs for software licenses and communication networks, the addition of approximately 12 new employees, and EIM membership fees. The initial cost and on-going cost estimates will be further refined as Avista conducts extensive planning assessments in 2019, including initiating a request for proposals for the software applications, selecting a System Integrator, and finalizing the internal program structure and associated resource plan.

Avista also recently reviewed the EIM benefit assessment conducted by Energy and Environmental Economics (E3) in the fall of 2017. E3 has conducted similar benefit assessments for several other utilities to help understand the potential value of EIM participation. The E3 assessment estimated that Avista could see a range of annual benefits from $2 to $12 million from EIM participation. There are four main study assumptions that drive the wide range of potential EIM benefits: the amount of flexible hydro Avista bids into the market, the amount of transmission that is made available for market transactions, the amount of renewable generation that is integrated into the Avista BAA, and the assumed EIM price volatility. Using Avista's best estimates for these critical study assumptions, Avista anticipates EIM annual benefits to be close to $6 million, with potential for benefits to move closer to the upper end of the study range depending upon observed market price volatility. Recent market price volatility experienced in 2018 significantly increased the benefits of current market participants. Both the Idaho Power Company (IPC) and Portland General Electric (PGE) achieved EIM benefits in 2018 that were over five times their anticipated benefits calculated by E3. Avista's resource mix and transmission connection to other EIM participants most closely matches IPC and PGE. Therefore Avista may achieve similar elevated EIM benefits during times of high market price volatility.

Q. Has Avista included any estimated costs or benefits associated with it joining the EIM in this filing?

A. No, it has not. At this time, the figures as noted above are estimates. The Company will address recovering in its next general rate case, costs associated with its joining EIM, and any corresponding benefits.

IV. OVERVIEW OF MAJOR GENERATION CAPITAL PROJECTS FOR 2017 -2018

Q. Please explain what the Company has included in this testimony with regard to generation capital projects.

A. My testimony provides capital project information and further support for major generating projects completed during 2017 and 2018. As discussed by Company witness Ms. Schuh, for projects included since our last general rate case and through the 2018 test year, Avista's capital witnesses including me, will describe the "major projects" completed. The determination of "major project" was based on any project, on a Washington-allocated basis, that was greater than $5 million for electric distribution and transmission, and greater than $2.5 million for natural gas, facilities, and fleet investments. Please note that Ms. Schuh provides the Washington-allocated values, but for my testimony I discuss projects, and their costs, at a system level. My testimony provides capital project information and further support for major generation projects completed during 2017 and 2018.

Q. For 2017 and 2018 capital additions, for which you are responsible, is the Company seeking to include all of those investments in general rates in this case?

A. Yes. While we are providing more detailed information in testimony and exhibits related to the major projects in 2017 and 2018, Ms. Schuh addresses in her testimony that the Company has included all 2017 and 2018 capital projects, especially given that they are already embedded in our 2018 test year. Exh. JRT-4 provides a summary listing of all program and project investments in my area of responsibility for 2017 and 2018, not just "major" projects.

Details about the "major" generation-related capital projects over the period 2017-2018 are discussed below, and business cases supporting each of these projects are provided in Exh. JRT-5. See Table No. 2 for the total cost of these major generation capital projects.

Table No. 2: 2017-2018 Major Generation Capital Project Totals

Projects ($)	2017	2018
Nine Mile Redevelopment	$7,679,798	$8,556,852
Little Falls Powerhouse Redevelopment	$10,258,268	$7,892,001
Total	$17,938,066	$16,448,853

Q. Please describe the capital planning process that Generation Production and Substation Support conducts before generation capital projects are submitted to the Capital Planning Group (described by Company witness Mr. Thies).

A. The capital planning process in Generation Production and Substation Support (GPSS) consists of a long-range forecast, a five-year forecast, and an execution plan. Descriptions of each phase of the planning process follow.

The long-range forecasting uses Maximo as the central repository for projects and their associated elements. Projects can be added to the long range forecast database in several ways:

- Informal project requests;
- Input from asset life cycle, condition, needs assessment;
- Periodic reports from Maximo of open corrective maintenance work orders;
- Periodic reports from Maximo of scheduled preventive maintenance work orders;
- Annual maintenance requirements;
- Regulatory mandates;
- Project change requests, drop ins, budget changes, etc.;
- Formal project request applications; and
- Efficiency and IRP-related upgrades.

The GPSS management team meets bi-yearly to review the long-range forecast, confirm that it is up to date and close completed projects. New projects are highlighted and noted. The impact of each additional project is reviewed. Any disagreement in the priority of projects is discussed until a solution is found.

The GPSS management team participates in an annual workshop in preparation for the budget cycle to prioritize the projects included in the five-year horizon. The team utilizes a formal ranking matrix to insure that the projects are prioritized consistently.

As projects for the next year are assigned, any capacity or budget constraints are identified and project schedules are adjusted accordingly by the GPSS Management Team. GPSS management and key stakeholders meet monthly at the Generation Coordination Meeting, the GPSS coordinated-team meeting, and specific Program or Project Steering Committee Meetings to discuss changes and progress of projects on the execution plan. Adjustments and consensus take place at these meetings.

Q. Company witnesses Mr. Vermillion and Mr. Thies identify and briefly explain the six "Investment Drivers" or classifications of Avista's infrastructure projects and programs. How then do these "drivers" translate to the capital expenditures that are occurring in the Company's generation area?

A. The Company's six Investment Drivers are briefly described as follows:

1. Customer Requested - Respond to customer requests for new service or service enhancements;
2. Customer Service Quality and Reliability - Meet our customers' expectations for quality and reliability of service;
3. Mandatory and Compliance - Meet regulatory and other mandatory obligations;
4. Performance and Capacity - Address system performance and capacity issues;
5. Asset Condition - Replace infrastructure at the end of its useful life based on asset condition; and
6. Failed Plant and Operations - Replace equipment that is damaged or fails, and support field operations.

The main drivers for each of the major generation-related capital investments in my testimony are discussed below for each project.

Q. Please describe the Nine Mile Redevelopment Project.

A. The Nine Mile Redevelopment is a continuing capital project to rehabilitate and modernize the Nine Mile Hydroelectric Dam.[2] Previous projects include the complete upgrades of Units 1 and 2 completed in 2016 and replacement of the Intake Deck and Debris System completed in 2017. Two major projects were placed into service in 2018 under the umbrella of this rehabilitation program. The largest project was the successful completion of the Sediment Bypass Enhancement, which included improvements to an existing passage for increased sediment diversion. The second project improved the filtration of the Cooling Water System to prevent forced outages caused by excessive debris during runoff. The investment drivers for these projects include: Mandatory and Compliance, Performance and Capacity, Asset Condition and Failed Plant and Operations.

Q. Did Avista consider alternatives to the Nine Mile Redevelopment Project?

A. Yes, the Sediment Bypass Enhancement project was one of four alternatives that were considered for this project. The alternatives evaluated included:

1. leaving the system nonfunctional;
2. returning the system to service at the existing capacity;
3. increasing the system to the maximum capacity of the existing tunnel; and
4. replacing the current tunnel to increase capacity further.

A study determined that the best value was to increase the capacity of the existing tunnel, given the improved impact of higher bypass flows, while avoiding the cost of a new tunnel for little additional improvement.

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[2] A private developer built the Nine Mile development in 1908 near Nine Mile Falls, Washington. Avista purchased the project in 1925 from the Spokane & Inland Empire Railroad Company. Nine Mile has undergone recent substantial upgrades. The development has two new 8-MW units and two 10-MW units for a total nameplate capacity of 36 MW.

Leading to the need for the Cooling Water Project, Nine Mile Units 1 and 2 experienced several outages in 2017 due to clogged cooling water equipment. Investigations identified river debris bypassing existing filtration as the cause of the clogging and Avista evaluated several alternatives to solve this problem. Due to the need to adhere to regulatory requirements and determine lowest operational costs, a new multistage filtration system was selected and added to the existing system.

Q. What was the timeline for the completion of the Nine Mile Redevelopment Project?

A. The overall rehabilitation project was scheduled to be completed in phases beginning in 2016 and ending in 2018 at the conclusion of the Sediment Bypass Enhancement project activities, and these timelines have been met. This included the procurement and installation of a Debris Management System, new Intake Deck to support the Debris Management System, and improvements to the Sediment Bypass System.

Q. Describe the system need for the Sediment Bypass and Cooling Water portion of the Redevelopment Project.

A. The original Sediment Bypass System was only partially functional and would have continued to allow significant amounts of sediment into the operating units without modifications and improvements. This decreased functionality caused damage to the runners, resulting in forced outages, increased operating cost, and continued maintenance issues. In addition to the improved flow and passage of sediment, it is necessary to maintain the operation of the bypass system throughout the year by removing any blockages from the intake area. As a result, a debris system removal and subsequent intake deck modification were required to ensure full functionality of the bypass system.

Failing to address the Cooling Water System outages on Units 1 and 2 would cause reoccurring outages each runoff season when debris is swept into the river and eventually plugs the existing filter system. In addition, significant maintenance efforts are required to return the units to service after the original filter system is plugged.

Q. Turning now to the <u>Little Falls Modernization Powerhouse Redevelopment Project.</u> Would you please describe that Project?

A. Yes. The Little Falls Modernization Program (LFMP) was initiated in 2010 to replace equipment at the end of its useful life associated with the generating units. From 2006 to 2010, the number and duration of forced outages at Little Falls increased due to equipment failure. This program was initiated to first replace the equipment responsible for the majority of the outages, followed by preparing the plant for the large generation unit upgrades, and concluding with projects structured to replace the majority of the generator's components.

The preparation work for the unit upgrade involved overhauling the crane to make it usable and safe again, constructing a warehouse for storage and staging of equipment, and upgrading the AC and DC electrical distribution system in the plant to handle the new equipment. The unit upgrades began in 2014 with four units being upgraded, one at a time. The last unit upgrade is scheduled for completion in the Fall of 2019. Each unit upgrade includes the replacement of the generator stators, generator cables, turbine shaft assembly, governor system, unit control and protection systems, re-babbiting of the bearings, reinsulating the field poles, and upgrades to the unit water, oil and air systems. Additional plant work is also included in this program that either directly or indirectly affects the generator units, such as lighting, backup generator, control room upgrades, and other subsystem upgrades. The Little Falls Spillway System is not included in this program.

Q. Did Avista consider alternatives to the Little Falls Modernization Program/Powerhouse Redevelopment?

A. Yes, multiple alternatives were considered including: leaving the plant as-is by replacing only the switchgear and exciter (Alternative 1); replacing the four generating units with larger, vertical units with more output and install new ancillary equipment and systems (Alternative 2); and the Selected Alternative - replacing four generating units with the same generating capacity and installing new ancillary equipment and systems. Table 3 shows the estimated capital and O&M costs for each of the alternatives.

<u>Table No. 3: Little Falls Modernization Alternatives Considered</u>

	Capital Cost	Annual O&M Cost
Status Quo	$0	$150,000
Alternative 1	$5,000,000	$20,000
Alternative 2	$83,000,000	$0
Selected Alternative	$56,100,000	$0

Alternative 1, though the lowest cost, was not considered a viable alternative based on the recent operating history of the generating units. They had become unreliable and there was no guarantee they would be fully operational at any time of the year. Alternative 2 did provide additional plant output, but the increase in generation for the extra cost was not as economical as just replacing all four generators in kind. The selected alternative was originally estimated to be approximately $56,100,000 vs. the current estimate for the Selected Alternative is approximately $53,072,000 (see Line No. 14 of Table 4).

Q. What was the timeline for the completion of the Little Falls Modernization Program/Powerhouse Redevelopment project?

A. Table No. 4 Little Falls Modernization Project Schedule shows the date, project description and project cost.

Table No. 4: Little Falls Modernization Project Schedule[3]

Line No.	Date	Project Description	Project Cost
1	January 2010	Program Begins	
2	March 2012 TTP	Exciter and Generator Breaker Repl Complete	$ 3,440,000
3	January 2014 TTP	Warehouse Construction Complete	$ 1,443,000
4	January 2014 TTP	Bridge Crane Overhaul Complete	$ 836,000
5	February 2015 TTP	Station Service Replacement Complete	$ 3,757,000
6	February 2016 TTP	Unit 3 Modernization Complete	$ 15,676,000
7	October 2016 TTP	Control Room Modernization Complete	$ 723,000
8	April 2017 TTP	Unit 1 Modernization Complete	$ 9,730,755
9	Remainder of 2017	Smaller projects transferred to plant	$ 527,513
10	June 2018 TTP	Unit 2 Modernization Complete	$ 7,121,062
11	November 2018 TTP	Backup Generator Install Complete	$ 770,940
12	Fall 2019	Unit 4 Modernization Complete	$ 8,357,253≈
13	June 2020	Plant Sewer Sump Upgrades/Misc Complete	$ 690,000≈
14		Total	$53,072,522

Q. What specific Little Falls Modernization Program/Powerhouse ("LFMP") Projects are discussed in this testimony?

A. In April 2017, the Unit 1 Modernization/Generator Upgrade was completed and transferred to plant for $9,730,755 (see Line 8 of Table No. 4). There were additional trailing costs for work, invoices, materials, redlines, as-builts, and project closeout that

[3] Only major projects under the LFMP Program are listed in this table, small projects are not shown. TTP shows the month and year of Transfer-to-Plant/In-Service. Project costs marked with ≈ are estimates.

transferred to service. Unit 1 was the second generator completed of the four units planned to be upgraded under the LFMP.[4]

Turning now to costs included in this case, in June 2018, the Unit 2 Modernization/Generator Upgrade was completed and transferred to plant for $7,121,062 (see Line 10 of Table No. 4). There were additional trailing costs for work, invoices, materials, redlines, asbuilts, and project closeout. Unit 2 was the third generator completed of the four units planned to be upgraded under the LFMP.

In November 2018, The Back-up/Emergency Generator installation and commissioning was completed and transferred to plant for $770,940 (see Line 11 of Table No. 4). There were additional trailing costs for work, invoices, materials, redlines, asbuilts, and project closeout. This is a new generator, as no previous back-up generator existed at Little Falls for the plant.

Unit 4 Modernization/Generator Upgrade is currently in process and is scheduled for completion in Fall 2019 (see Line 11 of Table No. 4). The current estimate for this is $8,357,253. There may be additional trailing costs for work, invoices, materials, redlines, asbuilts, and project closeout. Unit 4 was the final generator upgrade that is part of LFMP. This 2019 “major” project has been pro formed into the Company’s filed case, as discussed later in my testimony.

The last project to be completed under the LFMP is the Plant Sewer Sump replacement with an estimate of approximately $690,000 (Line 12 of Table No. 4). This work is scheduled to be completed in June 2020. There may be some additional miscellaneous work and costs

[4] The 2017 project costs were reviewed and approved by the Commission in Docket UE-170485.

that will also be completed in 2020. The 2020 projects however, have not been pro formed into the Company's case although they will be completed during the 2020 rate year.

V. <u>OVERVIEW OF PRO FORMA GENERATION CAPITAL PROJECTS FOR 2019</u>

Q. Please explain how the Company prepared the pro forma capital projects included in this case.

A. The Company started with the historical test period ending December 31, 2018. The Company then reviewed the planned capital projects for 2019 and determined what <u>major</u> capital projects should be included as pro forma capital projects consistent with the development of a Traditional Pro Forma Study. The Washington-allocated portion of these projects and the amounts included for revenue requirements are further discussed by Ms. Schuh.

Q. How did the Company determine what constitutes a <u>major</u> project for the 2019 pro forma period?

A. The Company determined that on a system basis, a significant project for electric generation is any project with a capital expenditure greater than $5 million when completed, as explained by Ms. Schuh. The table below shows the two generation projects that were identified that met this level. Details about the generation-related capital projects for 2019 are discussed below, and business cases supporting each of these projects are provided in Exh. JRT-5. The Little Falls Powerhouse Redevelopment program is discussed earlier in my testimony.

Table No. 5: 2019 Pro Forma Generation Capital Projects

Projects	2019
Cabinet Gorge Gantry Crane	$5,000,000
Little Falls Powerhouse Redevelopment	$9,047,253
Total 2019	$14,047,253

Q. It appears that the Little Falls Powerhouse Redevelopment project is also included Table No. 2 above, and fully described in the previous section of your testimony. Is that the case?

A. Yes, the Little Falls Powerhouse Redevelopment project is what we term "programs" in that they are ongoing, year over year projects, rather than being a distinct project. As such, the investment in these areas that occurred in 2017 and 2018 will occur again in 2019.

Q. Is all of the support for those programs in 2019 the same as what you previously described for 2017 and 2018?

A. Yes, the support is the same, and therefore I will not repeat that same information for those programs again in this section of testimony.

Q. Please describe the Cabinet Gorge Gantry Crane Rehabilitation Project.

A. The Cabinet Gorge Gantry Crane Rehabilitation Project was established primarily to bring the sixty-seven year old undersized crane up to current Crane Manufacturers Association of America (CMAA) standards and increase the lifting capacity to 340 tons.

Q. What was the timeline for the completion of Cabinet Gorge Gantry Crane Rehabilitation Project?

A. Even though concerns regarding the crane's functionality existed for years prior, a more thorough investigation was deemed necessary following the crane's use in the

Cabinet Gorge Unit 1 refurbishment in September 2015. After consideration of the investigation results, a capital project was initiated in January 2016. A professional services agreement for rehabilitation was executed between Avista and Simmers Crane Design & Services in March 2018. Construction began in March 2019 and is expected to be completed by October 31, 2019.

Q. What is the estimated cost of the project?

A. The project is estimated at a cost of $5.0 million.

Q. Describe the system need for this project.

A. The generating units of any hydro plant require periodic servicing, necessitating the removal of large internal components such as the rotor, generator shaft and turbine shaft. Of the four generating units at Cabinet Gorge, Unit 1 is the largest and heaviest with the rotor and lifting device weighing approximately 330 tons. The current crane's nameplate rating is 275 tons but, it has been authorized for occasional lifts of 125% per American Society of Mechanical Engineers (ASME) Code Section B30.2-3.1.7. During the last lift performed by the crane in September 2015, the mechanical team discontinued use of the main hoist motor due to operational inconsistencies. A decision was made to use the micro drive in lieu of the main hoist motor for the remainder of the lift, however, long term use of the micro-drive is not recommended. The Cabinet Gorge gantry crane must have a minimum lifting capacity of 330 tons in order to lift the components of Unit 1.

Q. Describe the alternatives evaluated and how this solution was chosen.

A. The alternatives evaluated included rehabilitation and re-rating the original gantry crane; replacement with like-for-like equipment, and total replacement with a redesigned gantry crane. Rehabilitation and re-rating of the original gantry crane was found to be the most cost-effective solution as the overall structural condition of the crane was found to be very good. The other two options would have been more costly.

Q. Please describe any material changes that impacted the project scope, schedule or budget.

A. A May 2017 inspection by Simmers Crane Design & Services determined that the overall structural condition of the crane was very good, and therefore a complete replacement of the crane was unnecessary. The decision to rehabilitate instead of replace was documented in change order #1 dated July 2017. This reduction in scope reduced the project budget from $7.3 million to $3.4 million. Subsequent change orders under the Simmers contract have resulted in budget increases of roughly $1.6 million, for a total of $5.0 million to transfer into service in October of 2019. This is less than the $7.3 million cost if the replacement alternative had been selected. This project was included as a pro forma capital addition in this filing.

VI. COLSTRIP GENERATION CAPITAL PROJECTS

Q. Before discussing the operation of and capital additions for Colstrip Units 3 and 4, please discuss the purpose of this testimony.

A. In the Company's prior Order No. 7 in Docket UE-170485, the Commission requested that "Avista must provide a more detailed examination of its justification for its investments at Colstrip in its next GRC",[5] and "if and when the Company requests recovery of a portion of Colstrip capital expense in a GRC, the request must be accompanied by a

[5] UE-170485, Order 07, Page 69, paragraph 205.

comprehensive, up to date analysis of the economics and environmental liability and risks of Colstrip Units 3 and 4 over their expected life."[6]

My testimony will discuss the prudency of capital additions completed during 2017 through 2019, while Ms. Andrews will discuss the recovery treatment of these assets, including the accelerated depreciation proposed in this filing.

Q. How are Colstrip capital decisions made and managed by the Company?

A. Avista actively participates in the capital decision-making process at Colstrip. Each year Talen, the plant operator, proposes a set of capital projects for Units 3 and 4, as well as for the plant-in-common. These projects are reviewed by one or more Avista representatives on an individual basis and also as an ownership group. Additionally, Avista and other Company representatives meet with Talen at least every other month to review plant operations including capital projects. Projects may be added or subtracted throughout the year as appropriate. While it is true that the ownership structure and operating agreement for Colstrip do not provide a line item veto of individual capital projects, and Avista only has a small ownership interest preventing it from stopping capital projects on its own, the Company nevertheless actively exercises its ownership rights while projects are being discussed. It should also be remembered that the compensation structure for the plant operator is cost-based and does not include a rate of return based on the capital spending at the plant. There is no incentive for the plant operator to spend foolishly. In fact, quite the opposite is true. The plant operator is an independent power producer that relies on low plant costs to ensure the plant is competitive in the market, so there is no financial incentive for them to spend needless

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[6] Id, fn. 314

capital. The plant operator's financial interests to keep costs as low as possible while meeting all regulations, are the same as all of the Colstrip owners and their customers.

Q. What is the overall reason for the on-going capital projects at Colstrip?

A. Continued capital projects are required in order to maintain a reliable operational facility and to meet regulatory obligations and environmental compliance requirements concerning overall site management. The Colstrip Generating Station consists of Units 1 and 2 – 333 (MW) that have each been operating since 1975, and are scheduled to shut down by July 2022, and Units 3 and 4 – 805 MW each operating since 1983 and 1986, currently assumed to operate until 2040. The entire facility must manage water and waste according to the following :

- The Site Certificate originally issued including the amended 12(d) stipulation under the Major Facility Siting Act in Montana, Nov. 1975.
- Federal Coal Combustion Residual (CCR) Rule, 40 Code of Federal Regulations (CFR), April 2015.
- Administrative Order on Consent (AOC) Regarding Impacts Related to Wastewater Facilities, MDEQ (July 2012), Settlement agreement entered (2016).

These regulatory obligations and environmental compliance requirements, in addition to maintaining a reliable, operational facility, requires a strategic approach to planning and completing certain Capital projects in order to meet required deadlines.

Q. How do the owners of Colstrip address regulatory obligations and environmental compliance requirements?

A. The Colstrip owner's group does not approach its regulatory obligations and environmental compliance requirements through a narrow perspective. The owners group, and specifically Avista, must always strategically manage the risk to both our customers and shareholders for the known and possible regulatory obligations at both the federal and state levels, while managing reliability and cost of all of our generating resources. The owners do not take this responsibility lightly and exercise careful diligence in gathering information at the point in time when strategic decisions must be made.

Q. Will these projects need to be completed regardless if/when the Plant is shut down?

A. Yes. The AOC has required an extensive evaluation process that included site characterization, clean-up criteria, risk assessment that resulted in a remedy reports (draft) and remedial action work plans. The draft and finalized documents can be found on the Montana Department of Environmental Quality (MDEQ) website specific to the Plant groundwater clean-up.[7] In addition, the AOC actions must also meet Federal CCR requirements and deadlines in the interim while maintaining reliable plant operation. The AOC remedial action work plans and Federal CCR are both regulatory obligations and environmental compliance requirements that must be met regardless of the Plant operational status. I will briefly discuss the projects completed in the 2017-2018 timeframe, as well as expected for 2019, below.

Q. In Footnote 314 of Order 07, Docket No. UE-170485 the Commission required the Company to provide a "comprehensive, up-to-date analysis of the economics and environmental liabilities" associated with Colstrip. Will you please briefly discuss how the Company is meeting this requirement?

A. Yes. As noted above, the Company takes the economic and associated customer impacts of operating, and meeting regulatory and environmental requirements very

[7] http://deq.mt.gov/DEQAdmin/mfs/ColstripSteamElectricStation

seriously. In addition to daily/monthly/yearly decisions, the Company also looks to the forward planning timeframe to determine best practices. This forward looking, ongoing economic analysis of Colstrip is undertaken through the Integrated Resource Plan (IRP). The currently-acknowledged IRP was submitted on August 31, 2017. The 2017 IRP was acknowledged by the Commission on May 5, 2018 in Docket No. UE-161036. The 2017 IRP found that "In the Expected Case, Avista's ownership interests in the plant remain cost effective for the next 20 years, although it dispatches less due to carbon regulation projections." (p. 12-2, 2017 IRP). The Expected Case for the 2017 IRP Colstrip analysis assumed the following:

1. Closure of Units 1 and 2 by 2022 and transferring of shared common costs to Units 3 and 4;

2. Selected Catalytic Reduction (SCR) added to Units 3 and 4 in 2028;

3. Expected Coal Combustion Residual capital requirements and water management issues; and

4. Coal prices for Units 3 and 4 escalating from the current contract after it ends in December 2019.

Besides the ongoing current and expected expenses modeled in the 2017 IRP, several scenarios concerning Colstrip were also modeled in order to determine any changes to the Preferred Resource Strategy ("PRS"). The 2017 IRP, Colstrip scenarios included the following changes to the Expected Case:

1. Retirement of Units 3 and 4 by the end of 2030 with replacement by a natural gas-fired peaker;

2. Retirement of Units 3 and 4 by the end of 2030 with replacement by a natural gas-fired combined-cycle combustion turbine;

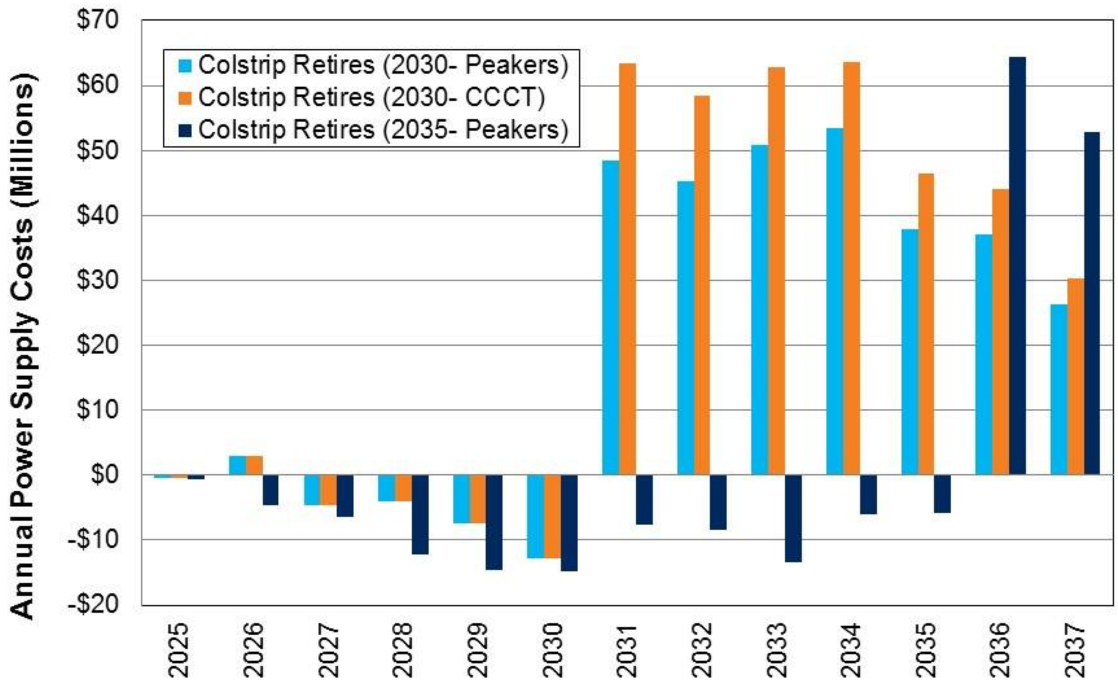
3. Retirement of Units 3 and 4 by the end of 2035 and replacement with a natural gas-fired peaker;

4. High Colstrip cost case assuming SCR in 2023, Units 1 and 2 shutting down in 2018 and subsequent shard cost transfer, adding a baghouse system for particulate removal by the end of 2023, and lower greenhouse gas emissions requirements in Montana beginning in 2024; and

5. Reducing greenhouse gas emissions 50 percent below the Expected Case.

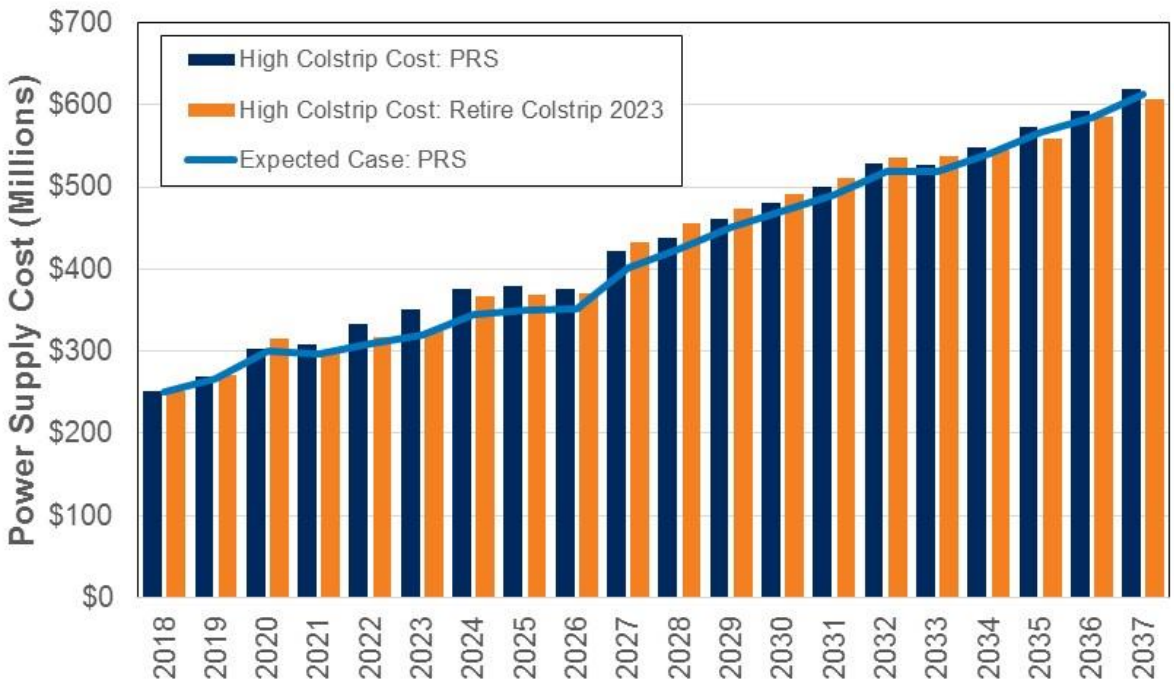
Figure No. 1 below shows the changes to annual costs of the three Colstrip retirement scenarios compared to the PRS, and Figure 2 compares the power supply costs of the High Colstrip Case with the PRS, the Retire Colstrip in 2023 Case and the Expected Case PRS.

Figure No. 1: Annual Cost Impact with Colstrip Retirement versus PRS[8]



[8] Exh. JRT-2, page 12-5, Figure 12.2.

Figure No. 2: High Cost Colstrip Scenarios Annual Cost[9]



The next IRP is in development and the due date was extended from August 31, 2019 through the end of February 2020 in Docket No. UE-180738, in anticipation of legislation changes. Legislation would require 100% clean energy serving Washington load by 2045, and coal no longer serving Washington customers after 2025. The current IRP will include the final version of the Washington Clean Energy Bill. When the current proposed legislation is enacted, Colstrip will not be used to serve Washington customers after 2025. A future shutdown date for Colstrip Units 3 and 4 for all other purposes is unknown at this time.

The next IRP is expected to include the following regarding Colstrip:

1. Estimates or a range of cost will be used for modeling of the coal contract until a new contract is signed.

[9] Exh. JRT-2, page 12-8, Figure 12.3.

2. Mercury controls will assume continued operations to meet Montana regulations.

3. Regional Haze glide path goals are expected to be met with the SmartBurn technology already installed and operational on Units 3 and 4. As discussed later in my testimony, the Company does not anticipate the need to install SCR during the 20-year IRP planning horizon because of SmartBurn and formal decision to close regional coal plants.

4. CCR costs and projects are <u>required</u> no matter how long the plant continues to operate.

5. Units 3 and 4 will be fully depreciated in 2027, or possibly by the end of 2025 if the "100% Clean" energy legislation is enacted. Additional details concerning the depreciation schedule for Avista's Colstrip ownership interests are discussed in Ms. Andrews' testimony.

In addition, the IRP filed in February of 2020 will include the results of any other approved legislation that will impact Colstrip. As discussed below, the capital projects included in this filing are only for environmental and operational requirements, and are not meant to extend the life of the plant.

Q. Will the Washington legislation requiring elimination of energy from Colstrip 3 and 4 by 2025 impact any of the capital projects in this case?

A. No. As discussed above, the Company is are required to meet several regulatory obligations and environmental compliance requirements, in addition to maintaining a reliable, operational facility. This requires a strategic approach to planning and completing certain capital projects in order to meet required deadlines. As such, we will continue to make the capital investments necessary to meet these requirements some of which extend beyond the operation of the plant. Put another way, the projects the Joint Partners have undertaken are necessary, irrespective of new legislation.

Q. Can you provide additional details concerning the "environmental liabilities" associated with Colstrip as discussed in Footnote 314 of Order 07, Docket No. UE-170485?

A. Yes. The environmental liabilities are managed and considered through Avista's active management of its ownership share in conjunction with the plant operator. This occurs with the input of Avista employees from Generation Engineering and Environmental Affairs, as Avista actively manages its shares of Colstrip Units 3 and 4, as described above, to ensure that the plant operator is complying with all relevant state and federal environmental regulations. The projects and costs needed for current and expected future compliance then feed into the economic models used for the IRP. The environmental liability areas covered for Colstrip include the following areas:

1. Coal supply: Coal mine reclamation is ongoing and Avista's share of reclamation costs are paid for as the coal is purchased. The Company has no additional costs or legal requirements beyond this cost which has already occurred. The mine owners are responsible for the actual reclamation.

2. Mercury controls: The current mercury abatement controls will continue to be used as long as the plant is in operation. There are no additional mercury controls expected to meet new requirements from the federal or state levels at this time.

3. Regional Haze: As discussed in the SmartBurn section of my testimony, the combination of SmartBurn and regional plant closures place Colstrip Units 3 and 4 within the glide path and SCR is not expected to be required.

4. CCR and water management: Please refer to this section later in my testimony describing the need for required ongoing capital spending on CCR and water management.

Q. Will you provide an update on the status of the Colstrip fuel supply?

A. Yes, the current coal supply contract for Units 3 and 4 expires at the end of 2019. The Company has been involved in negotiations to extend this contract, but Westmoreland Coal, the owner and operator of the Rosebud Mine that supplies Colstrip, filed for Chapter 11 bankruptcy in October 2018. A group of creditors purchased the Rosebud Mine assets, and that group accepted the current contract and will honor it for the rest of 2019. Negotiations with the creditors for a new contract are ongoing.

Q. Please now discuss which Colstrip generation capital projects you will discuss in your testimony.

A. I will address major projects at Colstrip completed and transferred to service for 2017 and 2018, as well as expected for 2019. Table No. 6 below illustrates the total amount of Colstrip generation capital projects that are included in this filing:

Table No. 6: 2017-2019 Colstrip Capital Additions (System)

Project	**2017**	**2018**	**2019**
Colstrip Capital Additions	$10,425,292	$4,528,290	$3,500,000

The totals above include 100+ Colstrip generation capital projects which have transferred each year. All of the completed projects for 2017-2018 are included in the Company's case. However, for ease of reference I will address only those projects greater than $400,000.

For 2017, the projects are as follows:

(1) Unit 3 Gas Deflection Arch Replacement $ 536,783

(2) Main Step-Up Transformer Overhaul $ 412,481

(3) SmartBurn project on Units 3 and 4 $2,020,962

(4) Water Management System / CCR $3,106,946

a. CCR – B Cell Clearwell Units 3-4 $1,454,632

b. Water Management System $1,189,667

c. Coal Combustion Residual $462,647

For 2018, the Colstrip capital projects were all done in support of the regulatory and environmental requirements concerning the long-term management of CCR. Included in the Company's case is a total of $4,528,290 in Colstrip generation capital projects. Those projects which exceed $500,000 are as follows: [10]

(1) CCR-B Cell Clearwell $ 556,975

(2) Waste Management System $2,582,468

Q. Please describe the first 2017 project, the Unit 3 Gas Deflection Arch Replacement project.

A. This capital project replaced portions of the gas deflection arch of the boiler at Colstrip Unit 3 & 4. This project involved replacement of erosion damaged tubes in the boiler. This is a critical internal component of the boiler that is made of boiler water wall tubes that was required to address the Failed Plant and Operations Investment Driver. This project went into service on June 30, 2017 with a final cost of $536,783 (vs. budget of $900,000).

Q. Describe the system need for this project.

A. The gas deflection arch, or "nose", of the boiler deflects gas outwards in order to equalize gas flow into the superheater sections. This nose arch is subject to more erosion

[10] As discussed by Ms. Andrews, the 2018 and 2019 Colstrip generation capital additions have been included in the Company's proposed treatment to recover the overall accelerated cost of Colstrip Units 3 and 4 assets over a 2027 depreciable life through the proposed Colstrip regulatory asset, and these balances would be recovered over a 33.75 regulatory amortization period. See Andrews' testimony at Exh. -1T

than some other areas due to slagging and soot blowing wear. Replacement of these areas prevents premature failure of the tubes that have been damaged by erosion.

Q. Would you describe how this solution was chosen?

A. Yes, this project covered replacement of certain sections of the nose arch that had become damaged by erosion. Erosion causes thinning of the tubes and can result in boiler tube leaks and subsequent unplanned outages. Avista's share of daily forced outage costs can easily exceed $75,000 per day. As a result this project was characterized by Talen as essential for reliable operation of the facility.

Q. Did Talen re-evaluate the alternatives?

A. No. There were no viable alternatives to reevaluate as discussed above.

Q. Describe Talen's project management process that was used to manage this process.

A. Talen, as plant operator, manages all of the projects. They use Primavera as a software solution to keep projects on budget and on schedule. Talen employs a number of Project Management Professionals and engineers who may be assigned to manage projects depending on complexity.

Q. Describe how Talen kept Avista management informed during this project.

A. Budget to Actual reports are issued to Avista by Talen on a monthly basis. The status of each individual project is given in this report.

Q. Please describe any material changes that impacted the project scope, schedule or budget.

A. Although Avista's share of this project was originally budgeted at $900,000, the observed damage during the outage was less than expected. A smaller section of the nose arch was replaced at a cost of $536,783 in 2017.

Q. Please describe the second project for 2017, <u>the Main Step-Up Transformer Overhauls</u> for Colstrip Units 3 and 4.

A. This was a two year project that involved overhaul work on all seven generator step-up transformers. Work included replacement of the cooling system, replacement of protective relay systems inside control cabinets and replacement of valves and pumps. These issues with the main transformers, if not remedied, could lead to outages at the plant. For example, transformer coolers have sustained hail damage and did not provide sufficient cooling during the summer months. Control cabinets had obsolete equipment, valves were starting to fail and pumps needed to be rebuilt or replaced. Oil leaks were another issue occurring more frequently at the gasket joints.

Q. What was the final cost of this aspect of the project and when did it go into service?

A. Avista's share of the final cost for 2017 was $412,481. Some of the project went into service in 2016 and some 2017.

Q. Describe the system need for this project and provide any financial analyses performed which support the project.

A. These transformers are critical for the operation of the units. If they fail, the cost of lost generation is extraordinary and Avista's share can easily exceed $75,000 or more per day depending on the price of electricity at the time the outage occurs.

Q. Describe the alternatives and how this solution was chosen.

A. The primary alternatives were to rewind, replace, or overhaul as specified for each of the main step-up transformers. Talen analyzed gassing data and determined that the transformers could be reliably operated well into the future without incurring the $14,000,000 cost of rewinding or replacing them. This overhaul project represented the least cost option that maintained the operational integrity of the step-up transformers.

Q. Please describe the third project for 2017, the SmartBurn Project.

A. SmartBurn was originally developed as the part of Alliant Energy's Combustion Initiative Program focused on the reduction of nitrogen oxides ("NOx") by optimizing the combustion process in coal-fired generation plants.[11] NOx is a haze-inducing pollutant produced during the combustion of coal that is regulated under the Regional Haze Rule. SmartBurn uses air staging technology to reduce the amount of NOx that is formed by reducing flame temperatures and improving the efficiency of the combustion of coal. The NOx emissions data received from Colstrip Units 3 and 4 after SmartBurn was installed would be used to determine the appropriate size of the technology needed to address the next expected step in NOx reduction - Selective Catalytic Reduction, which is described below.

Q. What is Selective Catalytic Reduction?

A. Selective Catalytic Reduction ("SCR") is a post-combustion control technology based on the chemical reduction of NOx into molecular nitrogen (N_2) and water vapor (H_2O). SCR typically combines a catalyst with ammonia injection to increase the NOx removal efficiency. The size, scope and amount of ammonia used by the SCR is directly related to the amount of NOx created during the earlier combustion process. Less NOx

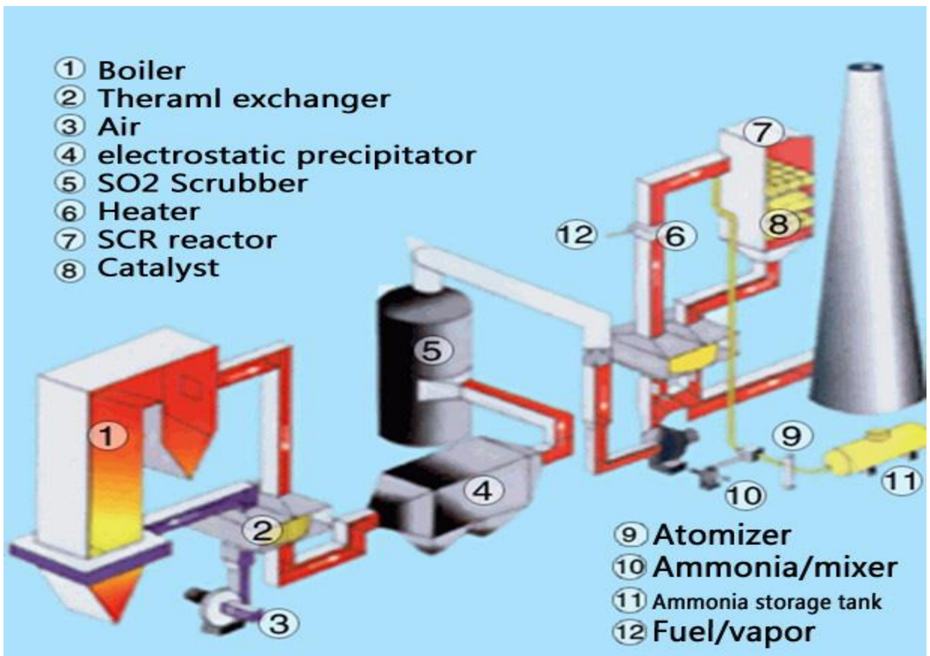
[11] http://www.smartburn.com/background.php

produced during the combustion phase results in the need for a smaller, and less costly SCR, and less chemicals to operate it.

Q. Can you provide a schematic showing where SmartBurn and SCR would be located in the coal combustion process?

A. Yes. Illustration No. 1 is a schematic showing where SCR (Item No. 7) would be located in the combustion stream, as opposed to the SmartBurn Technology which is deployed earlier in the boiler (Item No. 1).[12] This schematic, however, differs somewhat from the current configuration at Colstrip, which does not have SCR (Item No. 7) or an electrostatic precipitator (Item No. 4), but it serves to illustrate the point of where these technologies are in the coal combustion process.

<u>Illustration 1: Plant Schematic</u>



[12] https://www.tilemachinery.com/production-technology/coal-fired-power-plant-scrselective-catalytic-reduction-honeycomb-denitrification-catalyst/

The SmartBurn technology is applied to the boiler (#1 in above illustration) in order to improve combustion, while the SCR (#7 in above illustration) is employed at the end of the combustion process to remove additional NOx emissions.

Q. Did Avista/Talen consider alternatives to the Smart Burn Unit projects?

A. Talen reviewed a wide variety of NOx control solutions over the years, including selective non-catalytic reduction (SNCR), SCR, SmartBurn and others.

Q. How might SmartBurn impact the later addition of SCR?

A. SmartBurn is not a replacement for SCR, but as described above, it prevents some of the NOx from even being produced. The combination of SmartBurn, and associated measured data, results in the need for a smaller and less expensive SCR to limit the amount of NOx produced and to ensure compliance with the Regional Haze Rule. A smaller SCR requires less chemicals to operate, so a smaller amount of injected ammonia is needed, resulting in lower future operating costs.

The SmartBurn technology saves future capital expenditures, reduces future O&M expenditures, and provides an earlier environmental benefit by reducing the production of NOx. Using the SmartBurn technology before the installation of SCR is analogous to making a home as energy efficient as possible before adding solar panels, thereby reducing the overall size of the solar array and lowering subsequent cost. The energy efficiency investments do not eliminate the need for the energy produced by solar panels, but it reduces that need and results in a smaller number of panels needed to be purchased, installed and maintained. Put differently, energy efficiency should not be ignored altogether simply because it does not meet 100 percent of needs.

Q. Could you please provide additional background about when and why SmartBurn technology was installed on Colstrip Units 3 and 4?

A. Yes. In the 2012 decision timeframe, SCRs were being ordered in many surrounding states and previous litigation against Colstrip demanded a requirement of SCR for alleged "New Source Review" violations.[13] The owners, therefore, proactively decided to install SmartBurn in an effort to manage a future regulatory obligation, doing so in a strategic and cost-effective manner. Furthermore, SmartBurn was the last available, low cost, NOx pollution prevention emission control prior to the expected installation of a very expensive emission control (e.g., SCR).

Q. What was the timeline for completion of the Smart Burn projects and how much Capital cost is included in 2017?

A. The projects started in 2015. SmartBurn on Unit 4 was completed in 2016 and Unit 3 was completed in 2017. Avista's share of the final cost for 2017 was $2,020,962.

Q. What was known about NOx emissions requirements for Colstrip Units 3 and 4 when the decision to install SmartBurn was made in 2012?

A. There was a continuing expectation that future additional NOx reductions would be required for Colstrip Units 3 and 4. Avista's 2013 Electric IRP estimated SCR installation on Colstrip Units 3 and 4 could be required in 2027, and the Company ran scenarios to understand the implications of the SCR investment at that time. This was based on the Federal Implementation Plan for the State of Montana, finalized on September 18, 2012, and the expectation of a Reasonable Progress Report in September 2017.

[13] State of Montana Regional Haze Progress Report, August 2017, Montana Department of Environmental Quality, page 2-8 to 2-10.

Q. Did the owners of Colstrip expect SmartBurn to satisfy all future NOx emission reductions on Colstrip Units 3 and 4?

A. No. The SmartBurn technology reduced the first increment of NOx in the most cost-effective way, based on a review of the technology and the relatively low capital cost to install. Also, the use of SmartBurn technology was determined to be an integral part of any projected future control technology for Colstrip Units 3 and 4. SmartBurn reduces a significant amount of the target NOx reduction for a significantly lower cost than a full control modification approach. The early installation of SmartBurn also provides several years of operational boiler data that would allow for the design and eventual installation of the appropriately sized SCR or other control technology, once deemed appropriate. SmartBurn also provides an additional tool to maintain NOx emissions within the current operating requirements, as the plant ramps more frequently to support an increasing amount of variable generation in the region.

Q. Were there other benefits for the timing of installing SmartBurn?

A. Yes. The SmartBurn technology was installed on Units 3 and 4 during previously scheduled outages thereby reducing implementation costs. If the SmartBurn needed to be added at a later date for more near-term compliance needs, a separate outage might be required in consecutive years – the first outage to install the SmartBurn technology, and a second outage to install additional plant controls. Depending on market conditions at the time of the outage, the additional cost of an extra week long outage could be approximately one half the cost of installing SmartBurn itself. Finally, the operational effectiveness of SmartBurn may allow for a different and more cost-effective technology to be installed in place of SCR, because a lower amount of NOx is being produced by the plant. SmartBurn does not otherwise improve reliability or extend the life of the plant, so it has no bearing on the useful life of the plant or the Colstrip owner's decision to operate the plant. SmartBurn provides immediate environmental benefits through NOx reduction now and helps mitigate the cost of later SCR additions.

Q. Did the Colstrip owners' installation of SmartBurn result in verifiable NOx reductions?

A. Yes. The installation of SmartBurn has met the guaranteed emission rate reduction specified in the contract for this capital investment. The addition of SmartBurn on Units 3 and 4 improved NOx removal from 80 percent to approximately 86 percent, or a 6 percent improvement.

Q. Can you please summarize your testimony concerning the SmartBurn investment in Units 3 and 4?

A. Yes. Avista agreed, based on the information available at the time, to invest in SmartBurn technology on Colstrip Units 3 and 4 for the following reasons:

1. The decision to install SmartBurn was made in 2012 for installation in 2016 and 2017. At the time the decision to install was made, it was believed by the Company that SCR would be required on Units 3 and 4 in the 2020s.
2. SmartBurn <u>will not</u> extend the useful life, or even the reliability of Units 3 and 4.
3. SmartBurn, in fact, has produced positive environmental results, lowering NOx emissions and providing data useful for designing and selecting the SCR for the next step in NOx reductions expected in 2028.

Q. Did the Idaho Public Utilities Commission (IPUC) recently address the prudency of Smartburn?

A. Yes. In Order No 33953 Case No. AVU-E-1701 the Commission concluded that Avista's investment in the SmartBurn projects were prudent when made. They stated

> "We find that the SmartBurn equipment, while not required, was a cost-effective way to incrementally reduce NOx emissions now, thereby likely reducing the size and cost of emission controls."[14]

Q. Would legislation, expected to be approved in early May 2019, establishing 2025 as an end-date for closure of Colstrip as a Washington-resource make this investment imprudent?

A. No. There are a number of important reasons Avista supported approval of the Smart Burn project. Smart Burn provides compliance margin for the plant to be able to consistently remain in NOx emissions compliance. Although the plant was in compliance before the addition of Smart Burn, this project provided margin in the event upset conditions were/are encountered. In order to comply with the "Glide Path" that is associated with the federal Regional Haze rules, it was expected that a Selective Catalytic Converter would eventually be required. <u>At the time of the Smart Burn installations</u>, Talen and Avista believed that a SCR would be required around the 2027 timeframe. Talen analyzed Regional Haze requirements and determined that a final NOx Regional Haze solution would have required both Smart Burn and a SCR. The reason for this was that Smart Burn provides the first and easiest reduction of NOx by eliminating its up-front formation. By installing Smart Burn first and obtaining the necessary operating data, it would be possible to size a SCR appropriately. Furthermore, future chemical use in a SCR (ammonia) is reduced, and the incoming NOx is lower thus reducing O&M expense.

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[14] Order No. 33953, Case No. AVU-E-1701 page 13, paragraph 3

Q. Please describe the fourth project which concerns <u>Water Management System and CCR.</u>

A. The CCR - B Cell Clearwell Units 3-4 (item (a) of Project 4), Water Management System (item (b) of Project 4), and Coal Combustion Residual (item (c) of Project 4) should be considered building block projects that support the same strategic goal – to meet our regulatory obligations and environmental compliance requirements under the AOC and CCR. These projects are systematically replacing our historical methods of water and waste management, resulting in multi-year capital projects that are on-going to address groundwater quality at the Colstrip site. As such, these have been combined into one overall project for this testimony. For 2018, Avista's share of this fourth project was approximately $3,106,946.

A high level process description begins with raw water that is piped from the Yellowstone River to Castle Rock Lake, and ultimately to holding tanks at the plant site. This water is used in boilers, cooling towers and scrubber systems. Fly ash from the scrubber system is transported to the plants which then removes the excess water and deposits paste into disposal cells. Once the water is clear, it is ultimately recirculated back to the plants for reuse. All water is reused or lost through evaporation – this is a zero discharge facility. Throughout the years, water has been lost through seepage from the ponds that has contaminated the groundwater on the Colstrip site. The AOC is the primary Montana regulatory mechanism to address the groundwater contamination. This is a multi-year project due to the complexity and inter-related nature of the ponds.

Due to the significant amount of work required to meet these environmental regulations, these projects will continue to have specific capital projects in each year through the closure of the Colstrip site.

Q. Will you please describe the <u>2018 capital projects</u> for Colstrip?

A. Yes. Both projects (1) CCR-B Cell Clearwell for $556,975 and (2) Waste Management System for $2,582,468 are part of the multi-year projects which span several years as described with the 2017 project information. The 2018 Colstrip capital projects are all continuing support of the long-term management of coal combustion residuals (CCR) as required by Federal and Montana State regulations. These projects continue efforts to meet the Operational, and Regulatory and Environmental requirements and deadlines. These capital projects will continue until completed and the groundwater is clean, regardless of when or if the units are shut down. Each activity was evaluated and deemed to be in compliance with the Montana Department of Environmental Quality (MDEQ) AOC requirements. Alternatives were evaluated and these projects were ultimately mandated and approved to be in compliance with MDEQ requirements from 2016 through the closure of the Colstrip site.

Q. Turning now to 2019, expected Colstrip generation capital additions included in the Company's case total approximately $3.5 million. Are these expenses a continuation of those CCR and Wastewater requirements?

A. Yes. Projects included for 2019 Colstrip generation capital additions included in this case should be considered building block projects that support the same strategic goal – to meet our regulatory obligations and environmental compliance requirements under the AOC and CCR. These projects are systematically replacing our historical methods of water and waste management, resulting in multi-year capital projects that are on-going to address groundwater quality at the Colstrip site.

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

A. Yes it does.